Need for a Facility Exhibit

Cascade Renewable Transmission

Wasco, Hood River, and Multnomah Counties, Oregon

November 2025

Prepared for
Cascade Renewable Transmission, LLC

Submitted to
Oregon Energy Facility Siting Council

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Acronyms and Abbreviations

2023 CEP-IRP	Clean Energy Plan and Integrated Resource Plan
AC	alternating current
Addendum	PGE 2023 CEP-IRP Addendum
Applicant	Cascade Renewable Transmission, LLC (CRT)
ATC	available transmission capacity
BOEM	Bureau of Ocean Energy Management
BPA	Bonneville Power Administration
BPAT_SW	BPA Southwest region
CBRE	community-based renewable energy
CRITFC	Columbia River Inter-Tribal Fish Commission
DC	direct current
DER	distributed energy resources
Energy Vision	Energy Vision for the Columbia River Basin
HB2021	House Bill 2021
HVDC	high-voltage direct current
IRP	Integrated Resource Plan
kV	Kilovolt
MW	Megawatt
MWa	megawatt-average
NERC	North American Electric Reliability Corporation
NOI	Notice of Intent
NOPE	North of Pearl
NPV	net present value
NPVRR	net present value revenue requirement
NQC	net qualifying capacity
OAR	Oregon Administrative Rules
OPUC	Oregon Public Utility Commission
OR EFSC	Oregon Energy Facility Siting Council
ORS	Oregon Revised Statute
PGE	Portland General Electric
PNUCC	Pacific Northwest Utilities Conference Committee
Project	Cascade Renewable Transmission Project
PSE	Puget Sound Energy
ROW	right-of-way
SOA	South of Allston
SR 14	State Route 14
TSEP	Transmission System Expansion Plan
TSR	transmission service request
WA EFSEC	Washington Energy Facility Site Evaluation Council
WEA	wind energy areas
WECC	Western Electricity Coordinating Council
WOCS	West of Cross Cascade South
WRAP	Western Resource Adequacy Program
WSDOT	Washington State Department of Transportation

1 Introduction

Cascade Renewable Transmission, LLC (CRT; Applicant) proposes to construct and operate the Cascade Renewable Transmission Project (Project) – a high-voltage direct current (HVDC) (320 to 400 kilovolt [kV]), 1,100-megawatt (MW) electric transmission facility (Facility). The Facility would interconnect the existing Bonneville Power Administration (BPA) Big Eddy 500-kV alternating current (AC) substation located near The Dalles, Wasco County, Oregon (Eastern Interconnection), and the existing Portland General Electric (PGE) Harborton 230-kV AC substation located in Portland, Multnomah County, Oregon (Western Interconnection).

This exhibit was prepared to meet the submittal requirements in Oregon Administrative Rules (OAR) 345-023-0005.

2 Need Standards

2.1 Project Order Provisions

Under OAR 345-023-0020(3) and (4) an application for a transmission line must include the applicant's election to meet the Need Standard either under the least-cost plan rule, OAR 345-023-0020(1), the system reliability rule, OAR 345-023-0030, or by demonstrating that the transmission line is proposed to be located within a National Interest Electric Transmission Corridor designated under Section 216 of the Federal Power Act. In the NOI, the applicant stated that it intends to demonstrate need for the proposed facility under the system reliability rule. The applicant subsequently indicated that it will demonstrate the need for the facility under both the least-cost plan rule and the system reliability rule. The applicant must inform the Department if this election changes prior to the submission of the preliminary Application for Site Certificate.

2.2 Need Standard for Nongenerating Facilities (OAR 345-023-0005)

345-023-0005 This division applies to nongenerating facilities as defined in ORS 469.503(2)(e), except nongenerating facilities that are related or supporting facilities. To issue a site certificate for a facility described in sections (1) through (3), the Council must find that the applicant has demonstrated the need for the facility. The Council may adopt need standards for other nongenerating facilities. This division describes the methods the applicant shall use to demonstrate need. In accordance with ORS 469.501(1)(L), the Council has no standard requiring a showing of need or cost-effectiveness for generating facilities. The applicant shall demonstrate need:

(1) For electric transmission lines under the least-cost plan rule, OAR 345-023-0020(1), or the system reliability rule for transmission lines, OAR 345-023-0030, or by demonstrating that the transmission line is proposed to be located within a "National Interest Electric Transmission Corridor" designated by the U.S. Department of Energy under Section 216 of the Federal Power Act;

(2) For natural gas pipelines under the least-cost plan rule, OAR 345-023-0020(1), or the economically reasonable rule for natural gas pipelines, OAR 345-023-0040;

(3) For storage facilities for liquefied natural gas with storage capacity of three million gallons or greater under the least-cost plan rule, OAR 345-023-0020(1), or the economically reasonable rule for liquefied natural gas storage facilities, OAR 345-023-0040.

(4) If the proposed facility is a non-generating facility for which the applicant must demonstrate need under OAR 345-023-0005, the applicant must submit information about the need for the facility, providing evidence to support a finding by the Council as required by (1) through (3), including identification of the rule in Division 23 of this chapter under which the applicant chooses to demonstrate need.

RESPONSE

As described in the Organizational Expertise Exhibit, the Applicant (through supporting affiliates) is a successful developer and operator of transmission infrastructure, including three HVDC underwater transmission facilities in the U.S., completed in 2007, 2010, and 2013, with a total transmission capacity of 1,720 MW. The Applicant is not a generator, provider, or seller of energy, or of energy services; it does not serve retail energy customers; it is not a traditional integrated regulated electric utility; and does not possess certain powers, such as eminent domain, typically afforded to regulated utilities. However, if the Project is selected in the Northern Grid transmission planning process for cost recovery, the Applicant may recover the costs of the Project in the regulated rates of the Northern Grid Enrolled Parties, which are determined to benefit from the Project. Alternatively, the Applicant will recover the costs of the Project through bi-lateral contractual arrangements with a party or parties who benefit from the Project. By proposing the Project, the Applicant draws on its experience in using proven methods to provide needed transmission infrastructure to help meet both reliability and public policy needs on a least-cost basis.

The Applicant chooses to demonstrate the need for the Project under the least-cost plan rule (see Section 3.1) *and* the system reliability rule (see Section 3.2). The Oregon Energy Facility Siting Council (OR EFSC) may find the Project need is sufficiently demonstrated under one or both of those rules.

2.3 Least Cost Plan Rule (OAR 345-023-0020)(1) and (2)

(1)The Council shall find that the applicant has demonstrated need for the facility if the capacity of the proposed facility or a facility substantially similar to the proposed facility, as defined by OAR 345-001-0010, is identified for acquisition in the short-term plan of action of an energy resource plan or combination of plans adopted, approved or acknowledged by a municipal utility, people's utility district, electrical cooperative, other governmental body that makes or implements energy policy, or electric transmission system operator that has a governance that is independent of owners and users of the system and if the energy resource plan or combination of plans.…

(2) The Council shall find that a least-cost plan meets the criteria of an energy resource plan described in section (1) if the Public Utility Commission of Oregon has acknowledged the least cost plan.

2.4 System Reliability Rule (OAR 345-023-0030(1) through (3))

OAR 345-023-0030: The Council shall find that the applicant has demonstrated need for an electric transmission line that is an energy facility under the definition in ORS 469.300 if the Council finds that:

(1) The facility is needed to enable the transmission system of which it is to be a part to meet firm capacity demands for electricity or firm annual electricity sales that are reasonably expected to occur within five years of the facility's proposed in-service date based on weather conditions that have at least a 5 percent chance of occurrence in any year in the area to be served by the facility;

(2) The facility is consistent with the minimum operating reliability criteria contained in the Western System Coordinating Council Bulk Power Supply Program 1997-2007, dated April 1, 1998, as it applies either internally or externally to a utility system; and

(3) Construction and operation of the facility is an economically reasonable method of meeting the requirements of sections (1) and (2) compared to the alternatives evaluated in the application for a site certificate.

3 Need for the Project

The Applicant bases much of its analyses of need in the following sections on (1) BPA's announced Evolving Grid 1.0 and Evolving Grid 2.0 scope of transmission expansion resulting from BPA's 2022 and 2023 TSR Study and Expansion Process (TSEP) studies (Evolving Grid-Update on Transmission Activities, December 4, 2024; provided in Attachment 1), (2) PGE's 2023 *Clean Energy Plan and Integrated Resource Plan* (2023 CEP-IRP; provided in Attachment 2), along with associated addendums and updates and (3) a resource balance report prepared for the Applicant by Energy GPS (see Attachment 3). (2023 CEP-IRP; provided in Attachment 2), along with associated addendums and updates and (3) a resource balance report prepared for the Applicant by Energy GPS (see Attachment 3).

3.1 Least Cost Plan (OAR 345-023-0020(3))

(3) If the applicant chooses to demonstrate need for the proposed facility under OAR 345-023-0020(1), the least-cost plan rule, they must submit the following additional information in their application:

(a) Identification of the energy resource plan or combination of plans on which the applicant relies to demonstrate need;

(b) The name, address and telephone number of the person responsible for preparing each energy resource plan identified in subsection (a);

(c) For each plan reviewed by a regulatory agency, the agency's findings and final decision, including:

(A) For a plan reviewed by the Oregon Public Utility Commission, the acknowledgment order; or

(B) For a plan reviewed by any other regulatory agency, a summary of the public process including evidence to support a finding by the Council that the agency's decision process included a full, fair and open public participation and comment process as required by OAR 345-023-0020(1)(L), and the location of and means by which the Department can obtain a complete copy of the public record;

(d) Identification of the sections of the short-term action plan that call for the acquisition of the proposed facility or, as defined in OAR 345-001-0010, a facility substantially similar to the proposed facility;

(e) The attributes of the proposed facility that qualify it as one called for in the short-term action plan of the energy resource plan or combination of plans identified in subparagraph (i) or a demonstration that, as defined in OAR 345-001-0010, a facility substantially similar to the proposed facility is called for in the plan.

Under OAR 345-023-0020(2), OR EFSC shall find the Applicant has demonstrated the Project need if the capacity of the Project or *a facility substantially similar to the Project* is identified for acquisition in the short-term plan of action of an energy resource plan or combination of plans adopted, approved or acknowledged by a municipal utility, people's utility district, electrical cooperative, other governmental body that makes or implements energy policy, or electric transmission system operator that has a governance that is independent of owners and users of the system.

In the following sections, the Applicant demonstrates the Facility addresses the transmission constraints which exist on the AC network to secure firm deliveries from the Eastern side of the Cascade mountains to the load centers along the I-5 corridor, including Portland General Electric's (PGE) service territory. The required upgrades to the AC network are highlighted in BPA's Evolving Grid 1.0 and Evolving Grid 2.0 transmission expansion plan. Some of the critical flowgates, which are constrained include West of Cross Cascade North (WOCN), West of Cross Cascade South (WOCS), North of Marion and North of Pearl (NOPE). The Applicant will also demonstrate PGE's 2023 CEP-IRP and associated updates, support the need for incremental transmission to resolve the constraints on South of Allston (SOA), WOCS and NOPE. Finally, the Applicant demonstrates the Facility is a timely and economic alternative to the upgrades required to deliver to PGE's service territory from BPA's system East of the Cascades, particularly the 13 AC transmission upgrades indicated by BPA as required to deliver firm energy from BPA's Big Eddy substation to PGE's service territory.

Since the Project is a substantially similar facility which addresses several of the transmission needs raised in BPA's Evolving Grid 1.0 and 2.0 transmission plan stemming from BPA's 2022 and 2023 TSEPs, OR EFSC may find that the need standard under the least-cost plan rule has been satisfied.

Further, while specific transmission solutions have not been acknowledged by the Oregon Public Utility Commission (OPUC), the Applicant will demonstrate the record in PGE's 2023 CEP-IRP (along with associated updates) supports the need for incremental East-to-West transmission across the Cascades.

RESPONSE

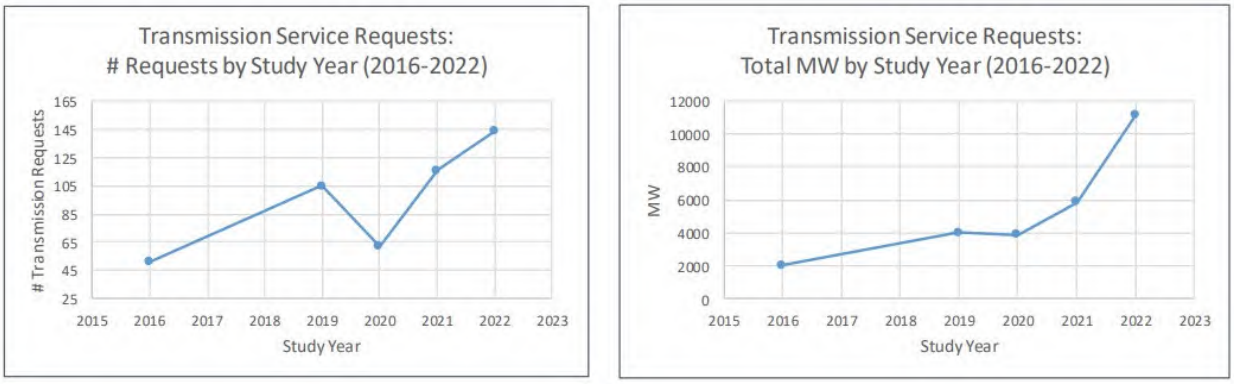
3.1.1 BPA Evolving Grid

The Applicant relies on BPA's 2022 and 2023 TSEPs and the resulting Evolving Grid 1.0 and Evolving Grid 2.0 transmission expansion plans. A lead person responsible for preparing BPA's transmission plans is Katie Sheckells, Associate Director, Transmission Marketing and Sales.

In April 2023, BPA launched its "Evolving Grid" effort to address Oregon and Washington clean energy targets, new generation resource additions, increased electrification of transportation, industry and buildings, and the growing need for resiliency in the face of extreme weather events. , increased electrification of transportation, industry and buildings, and the growing need for resiliency in the face of extreme weather events.

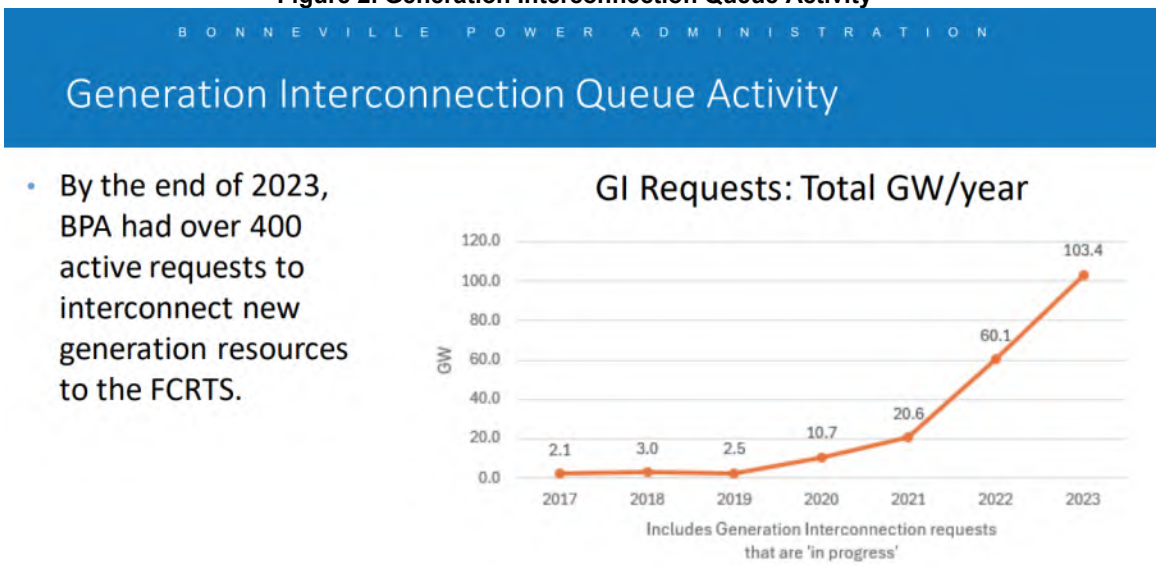
Evolving Grid developed out of BPA's TSEP which began in 2019. TSEP is a process to study requests for new transmission service in approximately yearly clusters. These requests for transmission are primarily from new energy projects seeking to deliver their power to customers in the BPA region utilizing BPA's high voltage transmission network. BPA has received increasingly large TSEP request volumes associated with a growing Generator Interconnection queue as shown in Figure 1 and Figure 2.

Figure 1. Transmission Service Requests Queue[1]



[1] BPA Evolving Grid Presentation, page 12, April 27, 2023.

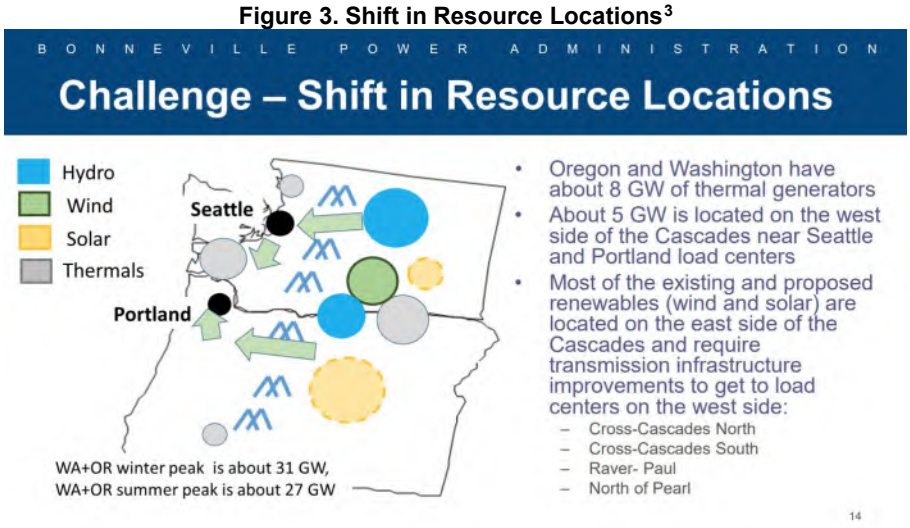
Figure 2. Generation Interconnection Queue Activity[2]



Through TSEP, BPA studies the requests and identifies any transmission upgrades necessary to grant service. The large volume of requests and increasing customer demand driven by renewable public policy in Oregon and Washington, plus load growth throughout the region, led to the need for major transmission expansion to grant most transmission requests, especially those delivering over the Cascades and into Portland or Seattle.

These emerging transmission constraints are driven by the factors highlighted in Figure 3 presented by BPA. There are three concurring seismic shifts underway: 1) retirement of westside fossil power plants, 2) construction of east side generation projects, and 3) rapidly growing demand throughout the I-5 corridor, all of which drive the need for more transmission over the Cascades and into the Portland and Seattle metro area.

Figure 3. Shift in Resource Locations[3]

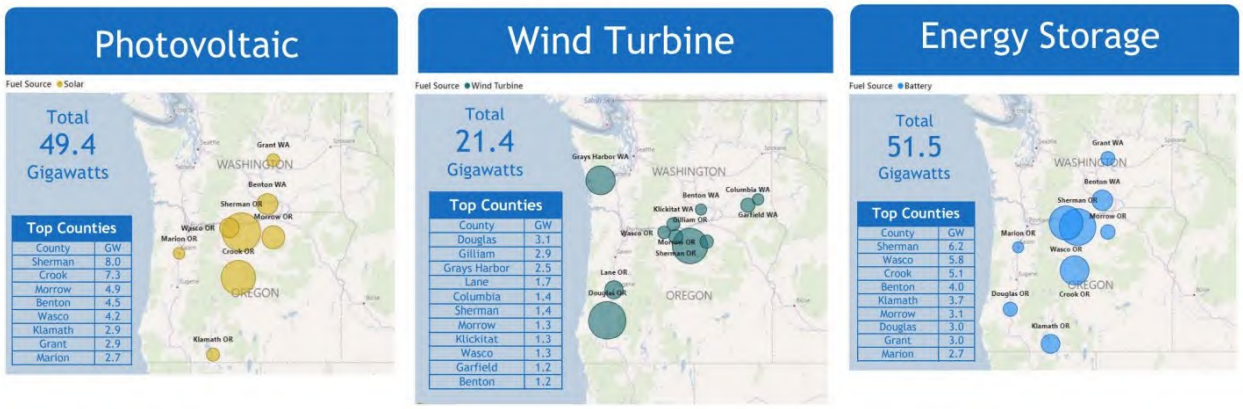


[2] BPA Evolving Grid Presentation, page 31, May 16, 2024.

[3] Joel Cook West Systems Power Pool Presentation, page 14, October 29, 2024.

The location of future energy resources is supported by BPA's Generator Interconnection queue, the status of which is provided by BPA in Figure 4. As shown, nearly every new energy generation project's location is east of the Cascades and/or south of Portland and thus constrained by transmission capacity over the Cascades or South to North up the Willamette Valley.

Figure 4. Locations of BPA-supported Future Generation Energy Resources[4]



Historically, BPA has placed responsibility for the costs of funding transmission needed for new generation facilities on the generation developer. However, funding the development of such major transmission upgrades is too onerous on individual generating projects in addition to the costs of developing the generator projects themselves. In addition, the cumulative TSR requests from all the generating projects are not a true reflection of the transmission needs driven by load growth and the shift in generation mix resulting from Oregon's HB2021 and Washington's CETA. To resolve this, BPA has developed the Evolving Grid process to move forward with key transmission upgrades outside of the normal TSEP process where the entities requesting the transmission service would be required to fund the projects.

BPA has hosted numerous meetings throughout 2023, 2024, and 2025 to outline the rational for Evolving Grid projects, define the process, and seek feedback from regional participants. BPA identified several project criteria for what would qualify a transmission upgrade as an eligible Evolving Grid project. These criteria include the following:[5]

1) Necessary main grid reinforcement regardless of specific generator locations
2) Necessary for load service
3) Provides transmission service for substantial MW of "mature" generation
4) Supports regional resource diversity
5) Supports network load growth and/or interconnection needs
6) Avoids future (within 10-year horizon) reliability need/costs
7) Regional level support of public policy

In essence, the Evolving Grid 1.0 and Evolving Grid 2.0 projects are BPA's "least regrets" transmission solutions to address the growing need.

[4] BPA The Evolving Grid Presentation, page 11, April 27, 2023.

[5] BPA Evolving Grid Project Portfolio Update, page 4, October 17, 2024.

The Evolving Grid projects were a by-product of BPA's TSEP process. Table 1 and Table 2 show two different transmission service requests (TSRs) in BPA's 2023 TSEP and the required upgrades to provide service for the requested TSRs. The first request shown was for 50 MW delivered from Big Eddy substation, the Project's eastern terminus location, to PGE. The second request was for 100 MW delivered from Big Eddy substation to Puget Sound Energy (PSE). For firm deliveries of electricity on an AC system, transmission capacity must be available across each of the various paths along which electricity flows.

Table 1. 50 MW TSR from Big Eddy Substation to PGE Service Territory

BIGEDDYCNTGS	PGE_CNTGS	50	1. Cross Cascades North Reinforcement 2. Schultz-Raver #3 and #4 Series Compensator 3. Schultz-Wautoma 500kV Series Compensator 4. Ross-Rivergate 230kV Rebuild 5. Big Eddy-Chemawa 500 kV Rebuild 6. Ostrander-Pearl #1 500kV Rebuild 7. Pearl-Sherwood-McLoughlin Reinforcement 8. North of Pearl 500kV Upgrade 9. Hood River Sub-grid Upgrades 10. North of Marion Upgrade #1 11. North of Marion Upgrade #2 12. Impact to Third-Party Transmission System (Portland General Electric: Pearl-Sherwood-McLoughlin, Ross-Rivergate, North of Pearl, North of Marion #1) 13. Impact to Third-Party Transmission System (PacifiCorp. Troutdale Bank)

Table 2. 100 MW TSR from Big Eddy Substation to PSE Service Territory

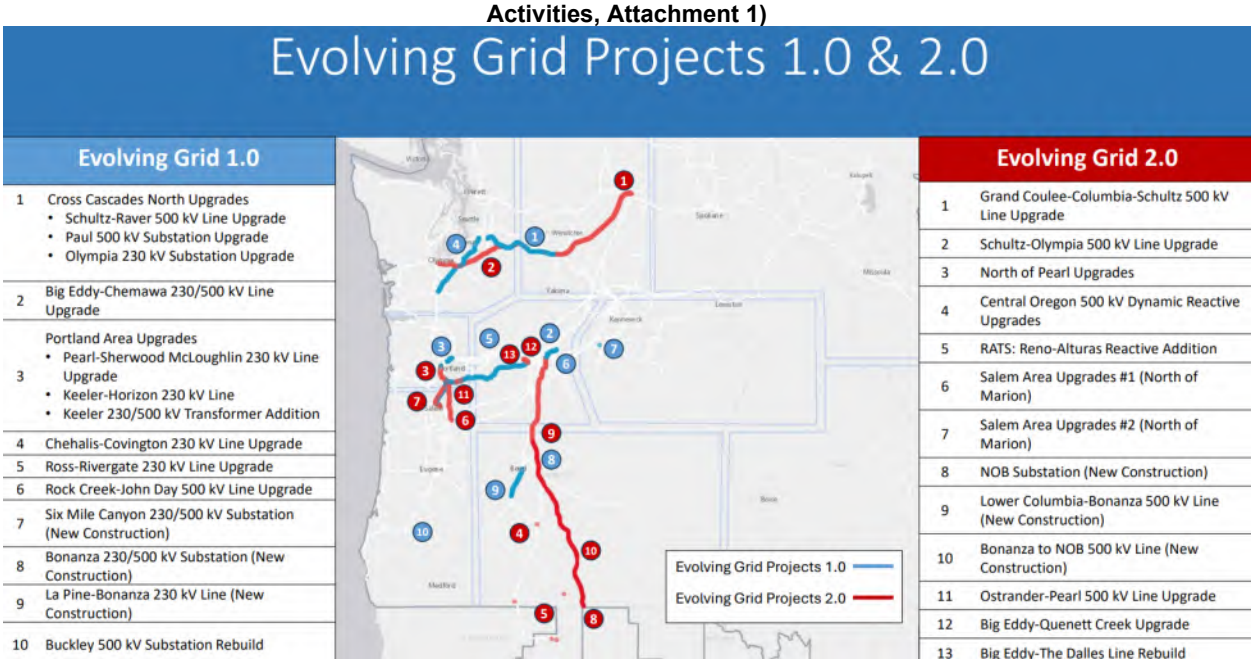
BIGEDDYCNTGS	PSEI_STHCNTGS	100	1. Cross Cascades North Reinforcement 2. Schultz-Raver #3 and #4 Series Compensator 3. Covington-Chehalis 230kV Rebuild 4. Schultz-Wautoma 500kV Series Compensator 5. Big Eddy-Chemawa 500 kV Rebuild 6. Ostrander-Pearl #1 500kV Rebuild 7. Pearl-Sherwood-McLoughlin Reinforcement 8. North of Pearl 500kV Upgrade 9.Schultz-Olympia #1 500kV 10. Hood River Sub-grid Upgrades 11. North of Marion Upgrade #1 12. North of Marion Upgrade #2 13. Central Oregon 500kV Dynamic Reactive Upgrades 14.Covington 500/230kV Banks 15. Impact to Third-Party Transmission System (Portland General Electric: Pearl-Sherwood-McLoughlin, North of Pearl, North of Marion #1)

The TSEP shows there are several material constraints across the AC transmission system from the Big Eddy substation to both PGE and PSE, all of which are triggered with minimal requests of 50 MW and 100 MW, respectively. For the PGE request, 13 different upgrades are required and for the PSE request 15 different upgrades are required. Interestingly, 10 of the required upgrades are common for securing TSRs to either PGE or PSE, demonstrating the common constraints which exist for East-to-West flows across the Cascades into both the southern and northern portions of the I-5 corridor. Further, every TSR request in the 2023 TSEP directed to PGE's service territory, other than offshore wind, which totaled 3,726 MW, required upgrades of North of Marion #1, and Big Eddy – Chemawa 500kV (WOCS) and 92% of those requests required upgrades of NOPE. These required upgrades include new major overhead transmission lines through national forests, extreme

wildfire risk areas and metropolitan areas, with many of the necessary upgrades having expected in-service dates of mid-to-late 2030s.

The results of BPA's 2022 and 2023 TSEP have led BPA to advance its Evolving Grid 1.0 and Evolving Grid 2.0 transmission expansion plan. A summary of those plans is included in Figure 5. To secure firm TSRs on BPA's system from East of the Cascades to PGE's service territory, Evolving Grid 1.0 projects 1, 2, 3 and 5 need to be completed. In addition, Evolving Grid 2.0 projects 3, 6, 7 and 11 also need to be completed.

Figure 5. BPA's Evolving Grid 1.0 and 2.0 transmission plan (December 4, 2024 Update on Transmission Activities, Attachment 1)



The Evolving Grid 1.0 and 2.0 projects are expansive, expensive, and will take a significant amount of time to complete. For instance, in BPA's Evolving Grid Project (EGP) 1.0 Summaries included in Attachment 4, BPA indicates direct cost estimates for the Big Eddy – Chemawa upgrade and the Cross Cascade North upgrades of $670 million and $400 million, respectively. Adding in a traditional 40 percent adder for BPA overhead results in a preliminary cost estimate for these two projects approaching $1.5 billion. Recognizing that both projects are still in the scoping phase and considering the history of cost creep for early-stage transmission development projects, these cost estimates could increase substantially and the respective completion dates of 2032 and 2031 could also significantly change. Adding in a traditional 40 percent adder for BPA overhead results in a preliminary cost estimate for these two projects approaching $1.5 billion. Recognizing that both projects are still in the scoping phase and considering the history of cost creep for early-stage transmission development projects, these cost estimates could increase substantially and the respective completion dates of 2032 and 2031 could also significantly change.

The Evolving Grid 2.0 projects are too early in the development process for BPA to provide a meaningful cost estimate or completion date for the individual projects. However, in BPA's Evolving Grid Project (EGP) 2.0 Summaries included in Attachment 5, BPA does provide an overall estimate of $3 billion for all the Evolving Grid 2.0 projects. Looking at the scopes for all the Evolving Grid 2.0 projects laid out in the EGP 2.0 Summaries, the Applicant estimates the combined cost of the Salem

Area Upgrades, North of Pearl upgrade and expansion and Ostrander-Pearl #1 500kV Line Upgrade comprise approximately 18.5 percent of BPA's initial $3 billion aggregate cost estimate or approximately $555 million of direct costs. Applying a 40 percent adder for BPA overhead, the costs for the three Evolving Grid 2.0 projects come to $777 million. With this approach, the Applicant estimates the combination of the Evolving Grid 1.0 projects 1 and 2 and Evolving Grid 2.0 projects 3, 6, 7 and 11, alone look to cost approximately $2.3 billion.

In lieu of the 13 upgrades BPA indicates are required to the AC system to meet the plan of service for the 50 MW TSR request from Big Eddy substation to PGE's service territory as shown in BPA's TSEP, the Project could be constructed as an alternative. As shown in Figure 6 below, the Project runs directly from BPA's Big Eddy substation to PGE's Harborton substation, as direct current (DC), not AC. With this DC electrical configuration and taking into consideration the system upgrades required as part of the Project's interconnection process, the Project by-passes the constrained circuits on the AC system. At an estimated cost of approximately $2 billion, the Project is an economic alternative to the required BPA upgrades.

3.1.2 PGE's 2023 CEP-IRP

PGE's 2023 CEP-IRP (Attachment 2), PGE's 2023 CEP-IRP Addendum: System Need & Portfolio Analysis Refresh (Addendum), filed on July 7, 2023 (Attachment 6), PGE's responses to Round 1 comments filed on September 6, 2023 (Attachment 7) and PGE's 2023 CEP-IRP Update filed with the OPUC on June 18, 2025 (Attachment 8) provide further support of the transmission need for PGE to meet its reliability and policy requirements on a least cost basis.

As indicated on the cover letter with PGE's 2023 CEP-IRP filing, the following person is responsible for preparing PGE's 2023 CEP-IRP.

Kristen Sheeran, Director of Sustainability and Resource Planning
121 Southwest Salmon Street
Portland, Oregon 83702

OPUC's IRP process is "an approach to utility planning which requires consideration of all known resources for meeting the utility's load."[6] These resources include both supply-side resources (such as generation plants) and demand-side resources (such as conservation and load management). OPUC has adopted guidelines that govern the development and acknowledgement of utility IRPs. As relevant here, the IRP process must include significant public involvement in the preparation of the plan.[7] Substantively, the plan must:

- evaluate all resources on a consistent and comparable basis;
- consider uncertainty;
- include as its primary goal the least cost to the utility and ratepayers, consistent with the long-run public interest; and
- be consistent with Oregon's energy policy.[8]

[6] OPUC Order No. 89-507, p. 8 (Apr. 20, 1981).
[7] OPUC Order No. 07-002, p. 1 (Jan. 8, 2007).
[8] Order No. 07-002, p. 2.

The IRP process requires a utility to identify several portfolios of different combinations of resources that can be used to meet the utility's load over a 20-year planning horizon. The portfolios are analyzed, and a preferred portfolio is identified, representing the best combination of costs and risks. Next, an action plan is developed to explain how the utility will obtain the resources identified in the preferred portfolio.

PGE filed its 2023 CEP-IRP with OPUC on March 31, 2023 (Attachment 2). The filing was docketed as LC 80.

In developing the 2023 CEP-IRP, PGE engaged in an extensive public process, which included a number of stakeholders, including representatives of political organizations, environmental groups, customer representatives, and others. PGE held numerous public meetings open to stakeholders. The meetings allowed stakeholders to provide input to PGE on all aspects of the planning process, including the development of the portfolios that were ultimately included in the 2023 CEP-IRP.

PGE's 2023 CEP-IRP divided the 20-year planning period into two periods: up to 2030 and beyond 2030. To inform the path to meeting the House Bill 2021 (HB2021) emission targets for 2030, PGE considered the following resources:

- On-Shore Wind: Oregon Gorge, Southeast Washington, Montana, Wyoming
- Solar: Central Oregon, Oregon Gorge, Willamette Valley, Desert Southwest
- Battery Storage: Lithium Ion, multiple durations
- Hybrid: Solar plus battery storage
- Pumped Storage Hydro Power
- Distributed Energy Resources
- Energy Efficiency (EE)
- Community-based Renewable Energy (CBRE; community-scale solar, solar + storage microgrids, in-conduit hydro)
- Off-shore wind[9]

Beyond 2030, PGE indicated other non-emitting technologies like hydrogen, nuclear, carbon capture or long-duration storage may prove cost-effective for serving customers in the region.

To analyze the portfolios, PGE relied on multiple models to forecast power prices, emissions, capacity need, energy need, and more. PGE used the Aurora Western Electricity Coordinating Council (WECC)-model to simulate electric wholesale market prices and dispatch for the Pacific Northwest region. PGE used the Aurora PGE Zone-model to simulate economic dispatch of PGE owned resources and candidate new resources. Outputs from the PGE Zone-model are inputs to ROSE-E (PGE's proprietary capacity expansion model) and an intermediary greenhouse gas model. The four models together enabled PGE to model resource operations and determine operating costs for the entire 20-year planning horizon. The analysis was based on the application of economic

[9] PGE indicated offshore wind would be included as part of the Preferred Portfolio in its response to comments filed on September 6, 2023. In those response comments, PGE indicated up to 1,000 MW of off-shore wind would be included in the Preferred Portfolio with the first installed capacity arriving in 2032.

principles and dispatch simulation to model the relationships between generation, transmission, and demand to forecast market prices. The operation of existing and future resources was based on forecasts of key fundamental elements, such as demand, fuel prices, hydroelectric conditions, and operating characteristics of new resources. The modeling simulated the regional electrical system to determine how utility generation and transmission resources operate to serve load.

For more information on the details of PGE's modeling approach, see Appendix H of PGE's filed 2023 CEP-IRP in Attachment 2.

OPUC's analysis and public process on PGE's 2023 CEP-IRP were extensive and thorough. The 2023 CEP-IRP was the subject of discussion at two separate OPUC public meetings. OPUC's process also allowed parties in the docket to submit written comments on two separate occasions. Over 10 individuals and organizations submitted written comments that PGE and OPUC considered. In addition to public comments, the OPUC staff undertook a comprehensive and independent review of PGE's 2023 CEP-IRP. As part of that process, the staff issued a 52-page report of opening comments, followed by a 33-page report of second round comments and recommendations. PGE responded with additional analysis and explanation to each of the staff reports.

At the end of the review process, PGE's Preferred Portfolio indicated the need for 1,200 MW of incremental transmission by 2030 to meet the requirements of HB2021, while meeting the growing load requirements reliably. PGE made the following key statements in its various 2023 CEP-IRP filings regarding the need for additional transmission:

- *"Portfolio analysis in this IRP indicates additional transmission need on PGE's system, across BPA's system and in additional climate zones."*[10]
- *"Transmission is a significant factor impacting the economics and timing of resource additions to meet HB 2021 targets. Transmission solutions are integral to meeting our targets."*[11]
- *"These results also demonstrate that the current forecasts of transmission capacity are insufficient to meet system needs over the planning horizon even after acquiring the entirety of the available potential for CBREs and cost-effective DERs."*[12]
- *"BPA's system is fully subscribed, and incremental transmission requests are unlikely to be granted until the late 2020s or early 2030s, pending significant upgrades."*[13]
- *"Achieving emissions targets reliably and affordably will require access to a wider geographic diversity of resources and the transmission solutions to access them."*[14]
- *"While demand response, energy efficiency and community-based renewable resources can offset some of the need for new resources, they cannot offset the need for most or avoid the need for new transmission options."*[15]

[10] PGE 2023 CEP-IRP dated March 31, 2023, page 207
[11] PGE 2023 CEP-IRP dated March 31, 2023, page 7.
[12] PGE 2023 CEP-IRP dated March 31, 2023, page 267.
[13] PGE 2023 CEP-IRP dated March 31, 2023, page 217.
[14] PGE 2023 CEP-IRP dated March 31, 2023, page 5.
[15] PGE 2023 CEP-IRP dated March 31, 2023, page 38.

- *"There is not a location on the BPA system, or beyond, to site generation that does not have an impact on South of Allston flowgate."*[16]
- *"The WOCS flowgate is currently known to be constrained and is viewed by some commenters in this docket as PGE's biggest obstacle to delivering new resources to company loads."*[17]
- *"It is worth noting that this calculator does not yet include the modifications necessary to account for the new BPA flowgates that are currently being implemented and impact PGE, including the North of Pearl flowgate (NOPE)….NOPE is a west-to-east cutplane flowgate located between Sherwood and Wilsonville and significantly impacts PGE's ability to deliver power to Portland and Hillsboro."*[18]

PGE's statements throughout its filed 2023 CEP-IRP make clear that three key flowgates are constrained and need to be resolved to access any incremental utility scale generation: (1) SOA, (2) WOCS, and (3) the newly formed NOPE flowgate. Given the nature of an AC system and the distribution of power flows on the networked system, all three of the constrained flowgates will require upgrades for PGE to access significant new resources for delivery into Portland/Hillsboro utilizing the high voltage AC network. As part of PGE's 2023 CEP-IRP public comment process, the Applicant filed comments laying out the implications for PGE of the three constrained flowgates. The Applicant's comments are provided in Attachment 9. As part of those comments, the Applicant makes clear that in lieu of building, upgrading or expanding multiple AC transmission lines to resolve the constraints on SOA, WOCS, and NOPE for delivery of new resources to PGE's service territory in Portland and Hillsboro, the Project could be constructed as an alternative.

OAR 345-001-0010 defines "facility substantially similar to the proposed facility" to mean:

> *"(a) A facility that uses the same fuel and substantially similar technology, that has substantially the same in-service date, and that has a direct cost not substantially greater than that of the proposed facility; or (b) A facility that is demonstrated to provide as good a mix of reliability, compatibility with the power system, strategic flexibility, environmental impact and direct cost as the proposed facility taking into account reasonable trade-offs among such factors."*

Figure 6 shows the general location of the three constrained flowgates relative to Portland and Hillsboro, the location of PGE's most significant load and load growth. The geographic location of the Project terminates directly within PGE's service territory at the Harborton substation, bypassing all three of the key flowgate constraints on the AC system.

Because of the implications of power flow distribution factors across a networked AC transmission system, constraints on all three flowgates would need to be alleviated to significantly increase delivery of energy into the Hillsboro area. This can be accomplished by implementing PGE's plan of upgrading South of Allston, upgrading Round Butte-Bethel plus BPA's Evolving Grid 2.0 Projects for the Salem Area Upgrades and North of Pearl upgrades and expansion. Alternatively, it could be resolved by constructing the Project.

[16] PGE comments filed on September 6, 2023, page 17.
[17] PGE comments filed on September 6, 2023, page 18.
[18] PGE comments filed on September 6, 2023, page 19.

Figure 6. Regional Transmission Landscape

Looking at an estimated cost to implement PGE's plan, The Tribal Business News published an article titled "Oregon tribe's $857M powerline upgrade could unlock renewable energy future" dated November 1, 2024 (see Attachment 10) which included a cost estimate for the 98-mile Bethel-Round Butte 230 kV to 500 kV upgrade at $857 million. Using the same cost per mile as the Bethel-Round Butte estimate, the cost of the 34-mile Trojan-Harborton expansion would be estimated at $297 million. Lastly, the Applicant looked at the cost estimates for the three BPA Evolving Grid 2.0 projects, North of Pearl, and the Salem Area Upgrades (also known as North of Marion #1 and North of Marion #2). As noted above, the Applicant estimated those projects along with Ostrander-Pearl #1 500 kV Line Upgrade would approach $777 million. Looking at the relative scopes of the three projects, the Applicant estimates the Ostrander-Pearl upgrade to comprise approximately 13.5% of the overall $777 million cost or approximately $105 million. Therefore, the cost of the North of Pearl and North of Marion projects required to fully implement PGE's transmission plan would be approximately $672 million. All combined, the costs to implement the AC system upgrades to implement PGE's transmission plan are conservatively estimated to be approximately $1.84 billion. The Project is a facility which is substantially similar to PGE's proposed transmission plan.

Not only would the Project alleviate the SOA, WOCS, and NOPE flowgate constraints (as noted above), the Project:

- Uses similar technology (i.e., high voltage transmission);
- Has a projected in-service date that is earlier than has been projected for completion of all the required AC line upgrades; and
- Has an estimated cost not substantially greater than the other proposed transmission facilities if the costs associated with resolving all the constraints on the AC flowgates are factored in. That does not ascribe any value to other unique benefits of the Project such as voltage support, lack of visual impact, and avoidance of risk associated with wildfires and extreme weather. Additionally, the Project also provides as good a mix of reliability, compatibility with the power system, strategic flexibility, environmental impact, and direct cost as the proposed facilities accounting for reasonable trade-offs among such factors. Specifically:
    - Reliability – The Project will use proven HVDC technology that is entirely controllable, with the added benefit of reducing climate-related risk such as wildfires.
    - System Compatibility – As noted above, WECC has determined that the Project will meet regional performance criteria.
    - Strategic Flexibility – The Project is already 5 years into development, including initiating permitting and siting processes, which is well ahead of other proposed regional transmission alternatives many of which will require expansion of existing ROWs. These alternatives, which would meet regional needs by 2035-2040, would likely require taking existing lines out of service for some period of time. Thus, by adding 1,100 MW of new transmission capacity by 2030-32, the Project would help alleviate the more immediate need and allow optimization of additional transmission facilities to follow.
    - Environmental Impact – As is shown in other exhibits in this application, the overall impact of the Project is expected to be minor and temporary, and no more impactful than

the prospect of widening existing ROWs and installing taller structures, much less building new high-capacity overhead transmission in a new ROW.

- Cost – As noted above, the Applicant believes that the current cost estimate of approximately $2 billion is economically reasonable compared to other alternatives, particularly when accounting for the benefits of voltage support, controllability, immunity from extreme weather and wildfire risk, and absence of visual impact that would not be available with overhead high voltage AC lines.

Accordingly, the Project provides substantially similar reliability and access to generation resources as the two PGE projects identified in the 2023 CEP-IRP, plus the North of Pearl and Salem Area Upgrades of the Evolving Grid 2.0 projects necessary to move energy from the western terminus of the Bethel-Round Butte upgrade into the Portland/Hillsboro area.

Moreover, as discussed below, there is a much higher transmission need by 2035 and 2040 to meet reliability needs and HB 2021 requirements, highlighting a long-term need for the Project *and* other significant AC system upgrades to proceed from a permitting perspective.

The significant transmission issues highlighted in PGE's 2023 CEP-IRP required PGE to perform a more rigorous analysis of the transmission constraints and potential solutions as part of its 2023 CEP-IRP Update. PGE filed its 2023 CEP-IRP Update with OPUC on June 18, 2025 (Attachment 8). PGE's 2023 CEP-IRP Update refreshes key inputs; in particular, load growth was increased to 2.8 percent annually over the 20-year planning horizon, a nearly 1.2 percent per annum increase over the assumptions in PGE's 2023 CEP-IRP. In addition, the update provides the results of a rigorous transmission analysis.

In its 2023 CEP-IRP Update process, PGE laid out the transmission options which it viewed as viable alternatives. As described further below, this analysis specifically identified the Project as a viable alternative.

In the PGE CEP & IRP Roundtable 24-6 public presentation on October 2, 2024 (see Attachment 11), on page 24, PGE noted three different transmission pathways:

1) What is available on the existing transmission system?
2) How much transmission capacity will be available to PGE when expected upgrades are made?
3) What can PGE do to bring more transmission capacity?

Pathway 2 focuses on what incremental transmission capacity can BPA provide with future upgrades. On slide 32 of the public presentation, when discussing BPA's Evolving Grid 1.0 projects, PGE states:

- "PGE's 2023 CEP/IRP Update will assume that these projects announced by BPA are successfully constructed and allocated as network assets due to their status as 'Regionally Needed Projects'".

Note this comment only focused on the Evolving Grid 1.0 projects and did not consider the other required projects in Evolving Grid 2.0. Nevertheless, PGE's statements and comments throughout

the 2023 CEP-IRP Update process indicate a significant need for incremental transmission to maintain reliability and meet the requirements of HB2021.

The significant transmission need is further reinforced in PGE's 2023 CEP-IRP Update. In Chapter 4. Transmission Update, PGE makes two key statements highlighting the need for transmission:

- *The transmission system serving PGE customers is highly constrained, with limited existing transmission available for future resources, particularly on BPA's system which supports limited resource additions prior to further transmission upgrades.*
- The NOPE flowgate has emerged as a significant constraint since August 2023, creating operational challenges that could be exacerbated by ongoing regional trends that are causing increasing south to north flows near Portland. Multiple projects are required to address reliability risks related to this flowgate.

The critical issues around the NOPE flowgate and how it may impact economic growth in a portion of PGE's service territory is captured in the following statement from page 71 of PGE's 2023 CEP-IRP Update:

- *As PGE anticipates significant load growth into the future from the semiconductor and data center industrial sectors, much of the forecasted growth will locate in the Beaverton/Hillsboro area on the west side of PGE's service territory. Existing constraints north of the NOPE flowgate* ***will limit industrial growth here.***

PGE goes on to lay out in Table 13 on page 77 of PGE's 2023 CEP-IRP Update the PGE/BPA Transmission Projects which are proposed to be implemented for the safe and reliable operation of the region's transmission system. Those proposed transmission projects are shown below in Table 3. As previously noted, the Project is a viable alternative to these projects for bypassing the SOA, WOCS and NOPE flowgates.

Table 3. Proposed PGE-BPA Transmission Projects

PGE-BPA Transmission Projects	BPA-only Transmission Projects
Pearl-Sherwood-McLoughlin Bifurcation & Reconductor	Big Eddy-Chemawa Upgrade (Evolving Grid 1.0)
N. of Sherwood Reconductor	Keeler Transformer Bank Addition (Evolving Grid 1.0)
Horizon-Keeler #1 reconductor	Pearl-Keeler 500kV #2 (Evolving Grid 2.0)
Horizon-Keeler 4000A upgrades	North of Marion Upgrades (Evolving Grid 2.0)
Ross-Rivergate (BPA Evolving Grid 1.0 Project)	Ostrander-Pearl #1 Line Upgrade (Evolving Grid 2.0)
Harborton 230 kV Rearrangement	
Willamette Valley Resiliency Project	

As part of PGE's transmission analysis in PGE's 2023 CEP-IRP Update, PGE assumes all of the projects listed in Table 3 will be permitted and constructed. In addition, PGE analyzed multiple transmission expansion alternatives as part of pathway 3 options. For each of the different transmission alternatives, PGE, with advice from a third-party consultant, assumed commercial operation dates (COD) for each transmission alternative. The projects PGE analyzed and their assumed associated MWs and CODs are reflected in Table 16 of PGE's 2023 CEP-IRP Update and are also shown below:

- Bethel – Round Butte – 3,000 MW with assumed COD in 2032
- Harborton - Trojan – 800 MW with assumed COD in 2035
- Gateway – 400 MW with assumed COD in 2035
- SWIP North – 400 MW with assumed COD 2035
- GreenLink – 627 MW with assumed COD 2035
- North Plains Connector – 600 MW with assumed COD in 2038
- CRTP (the Project) – 1100 MW with assumed COD in 2038

For each of the transmission alternatives listed above, as soon as PGE's model was allowed to select the transmission option, governed by the assumed COD, that alternative was selected as the least cost solution. This is shown below in Table 4, which is a copy of Table 30 on page 139 of PGE's 2023 CEP-IRP Update. Within the Transmission line item, the cumulative selection of transmission begins with 3000 MW in 2032, reflecting Bethel-Round Butte and finishes with 6927 MW in 2038, which reflects a 1700 MW increase over the previous year from the addition of the Project (1100 MW) and North Plain Connector (600 MW). It should be noted that all seven of the transmission projects analyzed by PGE were selected in the Preferred Portfolio as soon as they were assumed to be available for selection. In addition, all the BPA projects listed in Table 3 are also assumed to be completed as part of PGE's analysis.

Table 4. Cumulative resource buildout of PGE's Preferred Portfolio 2031-2038 (MW)

Resource	2031	2032	2033	2034	2035	2036	2037	2038
Wind	1362	2989	3420	3844	4274	4761	5352	5947
Solar (including hybrids)	1089	1089	1089	1089	1089	1089	1089	1089
Storage (including hybrids)	2250	2250	2250	2250	2732	3232	3732	4232
CBREs	155	155	155	155	155	155	155	155
NCE EE (MWa)	68	68	68	68	68	68	68	68
NCE DERs	16	16	16	16	16	16	16	16
Transmission	0	3000	3000	3000	5227	5227	5227	6927
Non-Emitting Contracts*	187	0	0	0	0	0	0	0
Cost-effective EE (MWa)	281	317	352	384	415	446	478	510
Cost-effective DR	266	284	299	312	325	336	348	356
2023 RFP Proxy Solar (including hybrids)	375	375	375	375	375	375	375	375
2023 RFP Proxy Storage (including hybrids)	775	775	775	775	775	775	775	775

* Values for contracts are annual, not cumulative.

Given the timing pressure of constructing a significant amount of transmission as quickly as possible, there are several factors that make the Project a viable and timely alternative to the AC transmission line upgrades and new builds:

1) The Project has been in development for 5 years and is the only project that is in the process of filing its permit applications. Assuming a 2 to 3-year timeline for issuance of permits after filing, the Project is on a development timeline, subject to global supply constraints for HVDC equipment, to achieve commercial operation in 2030-2032, well ahead of PGE's assumed COD of 2038. It is highly unlikely that all the required AC flowgate solutions (particularly North of Pearl and North of Marion #1 and #2) can be completed by 2032 given the current state of development of those projects.
2) The cost of the Project is estimated at approximately $2 billion, comparable to the cost estimates for the required AC system upgrades. A significant portion of the Project cost is for burying the DC cable for its entire 100-mile route, insulating it from the increased risk of wildfires and extreme weather and eliminating any visual impacts to the Columbia River Gorge. The benefits from reduced wildfire risk and storm hardening have always been difficult to quantify but given recent experiences in the region can certainly be considered significant and should be taken into consideration in any cost-benefit analysis when comparing alternatives. As an example of potential cost exposure, PacifiCorp in its September 30, 2024, 10Q, has estimated the 2020 and 2022 wildfires will cost the company $2.658 billion.
3) PGE's 2023 CEP-IRP Preferred Portfolio indicated 1,200 MW of transmission by 2030. However, the 2023 CEP-IRP also indicated a much higher transmission need by 2035 and 2040 to reliably meet HB2021 requirements. This much higher transmission need was confirmed in PGE's 2023 CEP-IRP Update. PGE's 2023 CEP-IRP Update shows multiple transmission projects being required over the 20-year planning horizon, including BPA's Evolving Grid 1.0 and 2.0 projects, PGE's Bethel - Round Butte and South of Alstom upgrades and the Project. The reality is that for the region to maintain reliability and meet its carbon emission requirements, the Project and multiple AC line upgrades will be required. The need for incremental transmission (particularly across the Cascades) is not in question. What is in question is which transmission projects can get developed, permitted, and constructed in a timely and cost-effective manner. For this reason, all viable transmission options which can address the growing need should proceed from a permitting perspective. This will allow the OPUC to approve the cost recovery and construction of those transmission lines that can economically meet the growing need ahead of when the need arises.

OAR 345-023-0020(4)

If the applicant chooses to demonstrate need for the proposed facility under OAR 345-023-0020(1), the least-cost plan rule, and relies on an energy resource plan not acknowledged by the Public Utility Commission of Oregon, they must submit the following additional information:

(a) The names, addresses and telephone numbers of members of any public advisory groups that participated in the preparation and review of each plan identified in (3)(c);

(b) A discussion of how the plan or combination of plans conforms to the standards in OAR 345-023-0020(1)(a) through (L) including citations to relevant portions of the plan documents or other supporting evidence;

(c) The expected annual emissions in tons of nitrogen oxides, PM-10 particulate, sulfur dioxide, carbon dioxide and mercury and a discussion of other environmental impacts, as compared to resources in the applicable energy resource plan;

(d) In addition to the information described in (b) and (c), if the applicant chooses to demonstrate need for a proposed natural gas pipeline or storage facility for liquefied natural gas under OAR 345-023-0020(1), the least-cost plan rule, and relies on an energy resource plan not acknowledged by the Public Utility Commission of Oregon, the applicant must include the information described in OAR 345-023-0040(3) if the energy resource plan or combination of plans does not contain that information. If the energy resource plan or combination of plans contains the information described in OAR 345-023-0040(3), the applicant must provide a list of citations to the sections of the energy resource plan that contain the information;

(e) In addition to the information described in (b) and (c), if the applicant chooses to demonstrate need for a proposed electric transmission line under OAR 345-023-0020(1), the least-cost plan rule and relies on an energy resource plan not acknowledged by the Public Utility Commission of Oregon, the applicant must include the information described in OAR 345-023-0030(4) if the energy resource plan or combination of plans does not contain that information. If the energy resource plan or combination of plans contains the information described in OAR 345-023-0030(4), the applicant must provide a list of citations to the sections of the energy resource plan that contain the information.

RESPONSE

Subsection 4 is not applicable to this Project.

3.2 System Reliability (OAR 345-023-0030)(4)(a) and (b))

(4) If the applicant chooses to demonstrate need for a proposed electric transmission line under OAR 345-023-0030, they must submit the following additional information:

(a) Load-resource balance tables for the area to be served by the proposed facility. In the tables, the applicant must include firm capacity demands and existing and committed firm resources for each of the years from the date of submission of the application to at least five years after the expected in-service date of the facility;

(b) Within the tables described in (a), a forecast of firm capacity demands for electricity and firm annual electricity sales for the area to be served by the proposed facility. The applicant must separate firm capacity demands and firm annual electricity sales into loads of retail customers, system losses, reserve margins and each wholesale contract for firm sale. In the forecast, the applicant must include a discussion of how the forecast incorporates reductions in firm capacity demand and firm annual electricity sales resulting from:

(A) Existing federal, state or local building codes, and equipment standards and conservation programs required by law for the area to be served by the proposed facility;

(B) Conservation programs provided by the energy supplier, as defined in OAR 345-001-0010;

(C) Conservation that results from responses to price; and

(D) Retail customer fuel choice;

RESPONSE

The system reliability rule requires a showing that the Project is: (1) needed to allow the BPA Southwest region (BPAT_SW) to meet its projected firm capacity demands or firm annual sales; (2) consistent with applicable NERC reliability standards; and (3) an economically reasonable method of meeting these requirements as compared to other alternatives.

First, the Project is required to meet projected loads. The load resource balance analysis performed by Energy GPS (see the report in Attachment 3) projects a resource deficiency (unmet peak-hour load) for the BPAT_SW region of 1,086 MW in 2030, 1,378 MW in 2031, increasing to 2,325 MW in 2035. For its analysis, Energy GPS used Pacific Northwest Utilities Conference Committee's (PNUCC) 2024 forecast for summer peak load growth over the next 10 years of 2.7 percent.

Narrowing the view to PGE's service territory, which would be serviced by the Project, Appendix F of PGE's 2023 CEP-IRP shows the results of PGE's load resource balance analysis. PGE's analysis indicates a median summer peak need of 1,136 MW in 2030, growing to 1,647 MW in 2035, with a further dramatic increase to 4,173 MW by 2040.

Second, the Project is consistent with the applicable mandatory and enforceable NERC reliability standards in effect as of September 18, 2015. As laid out in the Project's Western Electricity Coordinating Council (WECC) Phase 2 Path Rating Study Plan dated November 10, 2021 (Attachment 12), the Project's rating was evaluated using (1) applicable NERC, WECC, CAISO and/or more stringent local performance requirements or criteria, (2) post-transient governor power

flow solution techniques using GE PSLF v21.0 to assess TPL-001-4 NERC P1, P2, P4 and P7 contingencies and (3) transient stability contingency analysis for select TPL-001-4 NERC P1 and P7 contingencies. The results of the study and the system upgrades required as part of the Project to maintain NERC reliability standards were reported in the Project's WECC Phase 2 Analysis dated April 21, 2022.

As discussed in Section 3.1, there are three different transmission solutions to resolving the constraints on delivering firm energy from East of the Cascades into the I-5 corridor, particularly into PGE's service territory. The Project is shown to be an economically reasonable approach relative to the other alternatives when all costs and benefits are considered.

Accordingly, the Project meets the requirements of the system reliability rule and OR EFSC may find that the Applicant has demonstrated the need for the Project.

The load-resource balance tables in the Energy GPS report (Attachment 3) are based on a forecast of firm capacity demands for electricity for the BPAT_SW area to be served by the Project. As explained below, (1) the firm capacity demands for electricity are those reasonably expected to occur within 5 years of the facility's proposed in-service date based on weather conditions that have at least a 5 percent chance of occurrence in any year; and (2) Energy GPS has separated firm capacity demands into loads of retail customers, system losses, and reserve margins. Since Energy GPS was analyzing a region and not a single load serving entity, Energy GPS conservatively assumed there were no wholesale contracts for firm sales.

The BPAT_SW area is comprised of load from PGE, BPA Southwest, and a portion of PacifiCorp West load. The load forecast values for Energy GPS' analysis used the following:

(1) A 1-in-20-year peak load forecast from PGE's 2024 Local Transmission Plan Heavy Summer Cases for the years 2026 and 2034. The load between these years was linearly interpolated, and the 2025 load was deescalated by the average annual growth rate from PNUCC.

(2) The historical load for BPA Southwest Zone.

(3) The portion of PacifiCorp West load located West of the Cascades and north of Eugene, Oregon.

Without detailed reporting figures, Energy GPS estimated the PacifiCorp load within the BPAT_SW region at 31.1 percent of PacifiCorp West's total load. For load growth estimates for the 2024 historical BPA_SW and PacifiCorp loads, Energy GPS used PNUCC's report on *Northwest Regional Forecast of Power Loads and Resources* for August 2024 through July 2034 (see Attachment 13). On page 18 of the report, PNUCC forecasts peak summer load for the Northwest region for 2025 through 2034. From PNUCC's load figures, Energy GPS calculated the annual rate of load growth for each of the 10 years and applied those load growth rates to the 2024 historical load for BPA Southwest zone and PacifiCorp West. For years 11-20, Energy GPS used the average growth rate from the PNUCC figures for years 8-10, which was 1.6 percent.

Energy GPS' resulting load forecast for the BPAT_SW region is shown on page 5, Figure 1 of their report. In addition to the load forecast, Energy GPS calculated losses of 8 percent. Finally, Energy GPS applied a planning reserve margin of 16 percent, which is the same reserve margin applied by PNUCC. As indicated in footnote 1 on page 19 of the PNUCC report, the PNUCC load forecasts were net of energy efficiency.

Energy GPS' summer peak load forecast incorporates reductions in firm capacity demand resulting from the factors set forth in OAR 345-023-0030(4)(b).

As noted earlier, Energy GPS relied on the load forecasts from PNUCC's *Northwest Regional Forecast of Power Loads and Resources*. PNUCC aggregates the utility reported information for the entire region, to generate its report. As noted on pages 7-8 of the PNUCC report, energy efficiency and demand side management are key components of the load forecasts. With respect to energy efficiency, the PNUCC report notes on page 7,

> "Energy efficiency is an important resource to meet demand now and in the future, as well as a strategy to mitigate risk from uncertainty."

With respect to demand side management, page 8 of the PNUCC report states,

> "Demand response programs are an effective tool during summer and winter extreme weather events to shift consumption of electricity away from peak periods. As the grid becomes more strained, utilities are incorporating more customer demand response…The Forecast projects summer demand response to double, reducing the region's one hour peak by about 500 MW in 2024 to over 1,000 MW in 2033."

Energy GPS' approach of using PNUCC's rate of summer peak load growth captures the benefits of conservation programs, energy efficiency, and demand side management, since PNUCC's load forecasts captured the benefits of those programs.

PGE also evaluated energy efficiency and demand response in its long-term peak load growth forecasts for its load resource balance determination. Figure 60 on page 190 of PGE's 2023 CEP-IRP shows PGE's forecast of cumulative additional energy efficiency through 2030. Similarly, Figure 61 on page 191 of PGE's 2023 CEP-IRP shows PGE's forecast of cumulative additional demand response through 2030.

3.2.1 OAR 345-023-0030(4)(c)

(c) Within the tables described in (a), a forecast of existing and committed firm resources used to meet the demands described in (b). The applicant must include, as existing and committed firm resources, existing generation and transmission facilities, firm contract resources and committed new resources minus expected resource retirements or displacement. In the forecast, the applicant must list each resource separately;

RESPONSE

The load-resource balance tables for the BPAT_SW area to be served by the Project are included in Energy GPS' report in Appendix A in Tables 4 through 7 on pages 10-12 (Attachment 3).

The load-resource balance tables provide a forecast of existing and committed firm resources used to meet the BPAT_SW area's forecast demands. Energy GPS included existing generation and transmission facilities, firm contract resources, and committed new resources. No existing resources within the BPAT_SW area were assumed to be retired over the forecast period. Energy GPS has listed each resource separately.

3.2.2 OAR 345-023-0030(4)(d) and (e)

(d) A discussion of the reasons each resource is being retired or displaced if the forecast described in (c) includes expected retirements or displacements;

(e) A discussion of the annual capacity factors assumed for any generating facilities listed in the forecast described in (c);

RESPONSE

The assumed annual capacity factors for the generation resources are not directly applicable in a load resource capacity balance. Rather, the focus should be on the net qualifying capacity (NQC) of each resource. In the Energy GPS study, firm generation is calculated for individual generating resources using an NQC value multiplied by the resource's seasonal rated capacity. For thermal units, this ranges from 77 to 95 percent representing summer ratings and forced outage rates. For wind and solar, this ranges from 21 to 27 percent based on actual operation during the top 100 net load hours like the Western Resource Adequacy Program (WRAP) concept of capacity critical hours. For hydropower, it is based on the WRAP estimates of 77 percent, and for storage it is set at 80 percent, also based on the WRAP estimates. The NQC determination in MW for each generating resource used in the Energy GPS study is shown in Tables 6 and 7 in Appendix A of the Energy GPS report.

3.2.3 OAR 345-023-0030(4)(f)

(f) A discussion of the reliability criteria the applicant uses to demonstrate the proposed facility is needed, considering the load carrying capability of existing transmission system facilities supporting the area to be served by the proposed facility;

RESPONSE

NERC and WECC reliability criteria require the load serving entities of the BPAT_SW region to:

(a) reliably serve customer demand;

(b) operate the system within facility limits;

(c) maintain voltage through reactive power control; and

(d) maintain contingency reserves (i.e., operate the system such that the most severe single contingency does not result in loss of load or instability).

The following discussion shows that the Project is needed to satisfy these criteria.

NERC transmission planning standards provide the criteria for reliably serving future load and system performance under normal and outage conditions. These standards require that system facilities operate within NERC operating limits for a wide range of system conditions, including loss of generator units and transmission facilities.

As part of the WECC project coordination, path rating, and progress report process, the Applicant organized a regional project review group composed of western utility representatives to study the

addition of the Project to the western grid. Through the WECC rating process, the Project was determined to meet regional performance criteria.[19]

NERC transmission operations standards require that transmission schedules across WECC transmission paths do not exceed system operating limits. Currently, as noted in PGE's 2023 CEP-IRP, the intertie lines into BPAT_SW are constrained with little or no available transmission capacity (ATC). Without incremental ATC, the ability to reliably serve load is at risk. This can be seen in Table 7 of PGE's PGE 2023 CEP-IRP Addendum (Attachment 6), which shows that by 2028, PGE would be unable to procure 355 MW of required resources to meet its load without incremental transmission. This figure increases to 1,658 MW by 2030 and 4,568 MW by 2035. The Project will increase transmission import capability into BPAT_SW and will allow the load serving entities in BPAT_SW, including PGE, to maintain a margin between actual flow and facility limits.

Heavily loaded AC transmission lines consume large amounts of reactive power. To prevent voltage collapse and regional blackouts, balancing authorities maintain reactive power margin at critical locations on their systems. Certain outages on the AC system could drive reactive margins near the margin limits. The Project's transmission connectivity into PGE's service territory would reduce previously heavily loaded transmission lines and increase the reactive margin in the region. In addition, the Project would be capable of providing voltage-ampere reactive support independent of the MW transmission flow scheduled across the line, adding incremental value to preventing voltage collapse during a system event.

3.2.4 OAR 345-023-0030(4)(g)

(g) A discussion of reasons why the proposed facility is economically reasonable compared to the alternatives described below. In the discussion, the applicant must include a table showing the amounts of firm capacity and firm annual electricity available from the proposed facility and each alternative and the estimated direct cost, as defined in OAR 345-001-0010, of the proposed facility and each alternative. The applicant must include documentation of assumptions and calculations supporting the table. The applicant must evaluate alternatives to construction and operation of the proposed facility that include, but are not limited to:

(A) Implementation of cost-effective conservation, peak load management and voluntary customer interruption as a substitute for the proposed facility;

(B) Construction and operation of electric generating facilities as a substitute for the proposed facility;

(C) Direct use of natural gas, solar or geothermal resources at retail loads as a substitute for use of electricity transmitted by the proposed facility;

(D) Adding standard sized smaller or larger transmission line capacity;

[19] See WECC email Subject: Phase 3 Notification – Cascade Renewable Transmission Project HVDC Transmission Line Project – Granted Phase 3 Status (June. 27, 2022) – Attachment 1.

RESPONSE

3.2.4.1 Portland General Electric Preferred Portfolio

The preferred portfolio (portfolio 40) in PGE's 2023 CEP-IRP (Attachment 2) and PGE's 2023 CEP-IRP Addendum (Attachment 6), both of which include significant transmission expansion, represent the portfolio of resources with the best combination of expected costs and associated risks and uncertainties to meet PGE's growing load and House Bill 2021 (HB2021) requirements, and maintain its system in a safe, reliable, and economic manner. The preferred portfolio was selected on the basis of, among other things, extensive cost analysis, considering the discounted sum of all monetary costs, as described in OAR 345-001-0010(16) (providing the definition of "direct cost").

Chapter 3 of PGE's 2023 CEP-IRP Addendum describes the results of the portfolio analysis for roughly half of the 40 different portfolios considered (see Attachment 6). The total net present value (NPV) revenue requirement (NPVRR) and semi-deviation of NPVRR (variability risk) for each portfolio discussed are summarized in Figures 9, 10, 11 and 13 in Chapter 3. Table 5 shows the NPVRR, semi-deviation of NPVRR and max NPVRR (severity risk) for each of the 40 portfolios. The results for portfolios 14, 16, and 17 show the lowest NPVRR, variability risk, and severity risk. Those three portfolios demonstrate the value of transmission by analyzing unconstrained transmission scenarios. The NPVRRs of those three portfolios are nearly $20 billion less than every other portfolio evaluated by PGE and are nearly $17 billion less than the preferred portfolio.

Table 5. Expected-Case Total Portfolio Cost (2015-2034)

Portfolio	Cost – NPVRR	Risk metric - Variability	Risk metric - Severity
	(million 2023$)	(million 2023$)	(million 2023$)
Portfolio1	$ 42,041.68	$ 12,087.37	$ 58,511.15
Portfolio2	$ 42,772.21	$ 12,227.34	$ 59,418.70
Portfolio3	$ 41,611.73	$ 11,995.71	$ 57,976.33
Portfolio4	$ 43,138.75	$ 11,843.40	$ 59,302.57
Portfolio5	$ 43,777.14	$ 12,065.78	$ 60,222.24
Portfolio6	$ 41,480.76	$ 12,251.42	$ 58,298.25
Portfolio7	$ 42,041.68	$ 12,325.77	$ 58,686.47
Portfolio8	$ 41,657.14	$ 12,257.60	$ 58,665.65
Portfolio9	$ 42,041.68	$ 12,325.77	$ 58,686.47
Portfolio10	$ 42,142.68	$ 12,321.95	$ 58,746.24
Portfolio11	$ 42,457.33	$ 12,075.20	$ 58,762.76
Portfolio12	$ 42,160.67	$ 12,335.17	$ 58,789.13
Portfolio13	$ 42,041.67	$ 12,325.33	$ 58,685.80
Portfolio14	$ 20,268.65	$ 4,827.33	$ 28,407.09
Portfolio15	$ 45,594.59	$ 12,679.45	$ 62,539.33
Portfolio16	$ 20,741.09	$ 5,107.50	$ 29,397.03
Portfolio17	$ 20,190.84	$ 5,097.96	$ 28,950.73
Portfolio18	$ 42,044.77	$ 12,322.36	$ 58,685.12
Portfolio19	$ 42,302.47	$ 12,547.93	$ 59,211.49

Portfolio	Cost – NPVRR	Risk metric - Variability	Risk metric - Severity
	(million 2023$)	(million 2023$)	(million 2023$)
Portfolio20	$ 42,999.14	$ 12,199.48	$ 59,853.74
Portfolio21	$ 43,734.37	$ 12,194.65	$ 60,615.46
Portfolio22	$ 42,830.95	$ 12,395.13	$ 59,930.02
Portfolio23	$ 43,491.53	$ 12,377.91	$ 60,668.57
Portfolio24	$ 42,257.73	$ 12,382.60	$ 58,974.99
Portfolio25	$ 42,041.68	$ 12,325.77	$ 58,686.47
Portfolio26	$ 41,065.06	$ 12,638.89	$ 58,207.24
Portfolio27	$ 41,730.82	$ 12,207.37	$ 58,386.48
Portfolio28	$ 38,996.37	$ 12,209.95	$ 55,830.12
Portfolio29	$ 42,055.95	$ 12,262.64	$ 58,965.39
Portfolio30	$ 41,792.65	$ 12,155.78	$ 58,344.29
Portfolio31	$ 41,128.05	$ 12,324.63	$ 57,771.69
Portfolio32	$ 42,041.68	$ 12,325.77	$ 58,686.47
Portfolio33	--	--	--
Portfolio34	--	--	--
Portfolio35	$ 37,699.67	$ 11,560.71	$ 54,186.10
Portfolio36	$ 41,503.09	$ 12,043.61	$ 58,155.46
Portfolio37	$ 41,702.62	$ 12,059.20	$ 58,228.60
Portfolio38	$ 42,199.03	$ 12,044.97	$ 59,374.25
Portfolio39	$ 37,225.82	$ 11,523.72	$ 53,865.79
Portfolio40	$ 36,955.54	$ 11,875.92	$ 53,918.29

Source: PGE 2023 CEP-IRP Addendum, dated July 7, 2023

In addition, as noted above in the discussion of the Least Cost Rule, there are three different transmission solutions which can be considered to resolve the constraints on delivering firm energy into the I-5 corridor and PGE's service territory from East of the Cascades:

(1) The BPA Evolving Grid 1.0 and 2.0 projects shown in Figure 5, comprising Evolving Grid 1.0 projects 1, 2, 3 and 5 as well as Evolving Grid 2.0 projects 3, 6, 7 and 11. The longest lead time of these projects are those comprising Evolving Grid 2.0 and they are estimated for completion dates in the 2035-2040 timeframe.

(2) The PGE short-term plan projects of Trojan-Harborton and Bethel-Round Butte, plus the Evolving Grid 2.0 projects 3, 6 and 7 to resolve constraints from the Bethel substation to the Keeler substation. Again, the longest lead time of these projects are those comprising Evolving Grid 2.0 and they are estimated for completion dates in the 2035-2040 timeframe; and

(3) The Project, which has an estimated completion date (by the Applicant) in the 2030-2032 timeframe.

The analysis included in Section 3.1 demonstrated that the cost of the Project when compared to the alternative solutions is economically reasonable. This is particularly true when considering other

benefits of the Project such as reduced wildfire risk, reduced extreme weather risk, voltage support, and minimal visual impacts. Lastly, PGE's 2023 CEP-IRP Update selected every transmission alternative when it was available for the model to select. This further confirms resolving transmission constraints with the construction of new transmission projects and upgrades of existing transmission lines is the least cost economic alternative.

To further show the Project is an economically reasonable alternative, the Applicant commissioned Energy GPS to perform a production cost analysis, the results of which are included in the report in Attachment 15. In that analysis, Energy GPS used an Aurora model to develop the most efficient portfolio of resources under two different scenarios:

(1) no changes to the current transmission system, and

(2) an 1,100 MW transmission expansion of the West of Cross Cascade South (WOCS) transmission path, which is representative of the Project.

The analysis also evaluated two different load forecasts:

(A) annual growth rates in energy and peak demand of 0.6 percent and 0.9 percent, respectively, and

(B) an electrification case with annual growth rates in energy and peak demand of 3.0 percent and 1.8 percent, respectively.

Case B of the load scenarios more closely approximates the most recent load growth scenarios forecasted for the region by PNUCC.

In the analysis, Energy GPS allowed the Aurora model to select the most economic resources from a group that included eastern Oregon and Washington solar, western Oregon and Washington solar, eastern Oregon and Washington wind, Montana wind, western storage, eastern storage, and co-located solar and storage. Using the Aurora model and those resource options, in the case with the incremental 1,100 MW of east-to-west transmission, the resulting NPV portfolio cost was $5 billion less than the base case without any incremental transmission under load forecast case B and $4.1 billion under load forecast case A.

Further, PGE's 2023 CEP-IRP economic analysis of alternatives included evaluation of demand side management, as required by OAR 345-023-0030(4)(g)(A). In the 2023 CEP-IRP process, PGE committed to implementing all cost-effective, demand-side management measures prior to considering supply-side alternatives, including the Project. While demand-side management is a valuable tool, PGE determined that demand-side management alone is not sufficient to bridge PGE's load growth requirements. Further description of the analyses and assumptions associated with demand-side measures is included in Attachment 2, Chapter 6.2.2. PGE's 2023 CEP-IRP Update further supported that demand side management would not be sufficient to meet PGE's needs.

In addition, PGE evaluated the construction and operation of electric generating facilities, including battery storage, as required by OAR 345-023-0030((4)(g)(B). The portfolios considered in PGE's 2023 CEP-IRP include a variety of generation and storage resources. Based on PGE's 2023 CEP-IRP analysis, portfolios containing these resources and no transmission expansion were expected to result in higher total costs (as defined by OAR 345-001-0010(16)) than the portfolios that included expanded transmission, including the preferred portfolio (see Table 5).

Finally, PGE evaluated the use of distributed energy resources (DER) at retail loads, as required by OAR 345-023-0030(4)(g)(C). DER resources were included in multiple alternative portfolios considered for PGE's 2023 CEP-IRP. PGE's 2023 CEP-IRP cost analysis indicated that the costs associated with alternative portfolios that included DER resources and no incremental transmission were expected to be greater than the portfolios that included incremental transmission, including the preferred portfolio (see Table 5).

3.2.4.2 Alternatives Suggested in Public Comments

In accordance with the Project Order, the Applicant addresses the following alternatives identified in public comments received in response to publication of its Notice of Intent (NOI).

Aboveground Transmission

Designing the route for a major new transmission facility is a function of, among other things, the chosen points of interconnection to the electric grid. The substations at the points of interconnection must be sufficiently robust to be able to accommodate a new high-voltage line, both physically and electrically. The Applicant identified the existing BPA Big Eddy substation (500kV) and the existing PGE Harborton substation (230kV) as having sufficient physical space and electrical capacity to accommodate a new high-voltage line at an acceptable cost, while meeting the needs of providing significant new transmission capacity to meet growing energy demands and achieve public policy goals.

The Applicant is aware of generally east-to-west overhead transmission lines proposed by others that would make use of existing rights-of-way (ROWs). None of these alternatives would interconnect directly into the greater Portland area, and they would require additional transmission expansion to do so, such as expansion needed to overcome existing constraints on the south-north North of Pearl (NOPE) flowgate. Given the existing constraints on the AC transmission system, construction of multiple overhead transmission lines would be required to increase flows into the Portland area by the same 1,100 MW as the Project.

The Project, as proposed, is an HVDC facility that affords benefits to the regional electric system that would not be provided by an AC facility. As such, it requires converter stations near the points of interconnection to convert AC power to direct current (DC), and DC back to AC. Some of the important criteria for choosing the converter station locations for the Project are listed in the Background Information Exhibit.

Given the needs for additional transmission directly into the greater Portland area and to site converter stations at a reasonable distance from the interconnection points, the constraints on realistically routing overhead transmission between the two points are severe if not impossible. The Applicant has no power of eminent domain that would likely be necessary to acquire portions of a new ROW. PGE and BPA have proposed using existing transmission ROWs that might be widened to accommodate overhead transmission comparable to the Project and may well be ultimately necessary. But as discussed in this exhibit, the acknowledged need for additional transmission capacity beyond 2030 is significantly greater than the Project's 1,100 MW, which can be put into service in the 2030-2032 timeframe. In any event, the use of existing ROW is not a realistic alternative for the Applicant since these are owned and controlled by such entities as PGE or BPA; thus, not available to the Applicant. Additionally, these ROWs traverse areas of wildfire risk over the Cascades that the Project is designed to avoid. The Project, as a controllable DC line, would provide

system reliability benefits that would not be available as an above ground AC transmission project. Theoretically, there could be plausible routes that use highway ROWs (Interstate 84 in Oregon, or State Route 14 [SR 14] in Washington) or existing railroad ROWs in either state. However, any of these ROWs have several physical barriers (such as narrow sections of ROW that would not allow transmission structures, bridges, tunnels, etc.) that would prevent the unimpeded construction of approximately 100 miles of overhead transmission. Moreover, in Oregon, the co-location of utilities parallel to the ROW is currently prohibited and would require the approval by exception of the Oregon Department of Transportation and the Federal Highway Administration. Even then, the prospect of routing highly visible transmission facilities through the Columbia River Gorge National Scenic Area is extremely unlikely.

For these reasons, the Applicant believes that overhead transmission is not an alternative to the proposed underwater cable route, and that overhead transmission currently proposed by others are not equivalent alternatives.

Transmission Along Rail Rights of Way

The Applicant has considered the use of existing rail corridors in Oregon and Washington for burying HVDC cable between the selected interconnection points. However, rail ROWs on each side of the Columbia River present more than one insurmountable obstacle. In designing the route for a long, linear project such as a transmission facility within a narrow corridor, the presence of even one insurmountable obstacle renders the entire concept not feasible, even if most of the route would be feasible.

Underground placement of high-voltage cable requires far more space for construction operations than simply the width of the trench, even though the workspace requirement is temporary. Space is needed for machinery, equipment, materials, movement of construction crews, and temporary placement of excavated material. Even after trenching is complete, the jointing of cable sections requires physical space for jointing operations – typically, a covered, heated area approximately 12 feet by 25 feet set up temporarily at the location of each joint to allow jointing specialists to work safely.

There are several locations along the rail ROWs on both the Oregon and Washington sides of the river where there is insufficient space to safely accommodate the required work. In particular, there are locations where the ROW is constrained by sheer rock cliff on one side and the edge of the river on the other. There also are several locations where the ROW narrows to a single track, such that trenching operations would unavoidably conflict with railroad operations. In narrow, constrained areas such as these, there are often no alternative routes that would allow trenching operations to circumvent or move away from these areas and rejoin the ROW further along the route.

In examining the rail ROW on the Oregon side, the Applicant identified 17 culverts or overpass bridges, three tunnels, and five causeways. For these types of conditions, it is likely that the cable could not be buried but instead would be attached to the structure. Structural analysis of each such situation would be required to determine if the structure could safely bear the additional weight of the cable. If not, the structure would need to be reinforced, if possible; otherwise, the structure would not be usable for this purpose. There are many instances of similar conditions on the rail ROW on the Washington side, as well as extremely narrow ROWs and single-track areas.

Even if there were theoretical technical solutions for the various obstacles to be encountered along the rail ROWs, using the ROWs would require the permission and approval of the railroads themselves, which is not guaranteed. As noted previously, the Applicant does not have powers of eminent domain.

For these reasons, the Applicant considers the use of rail ROWs for cable routing to be not feasible.

Transmission on Washington Side of the Columbia River

The Applicant conducted a detailed feasibility review of using SR 14 to route an underground cable system that would cover much of the distance between the two points of interconnection. The review considered the stretch of highway between Vancouver and Lyle, a distance of approximately 81 miles. This review is included as Attachment 16. On the basis of the review, there are numerous reasons to conclude that this alternative is not feasible, including:

- The presence of approximately 350 physical obstacles (tunnels, roundabouts, bridges, culverts, causeways, etc.), some of which are many decades old; the integrity and load bearing capability of crossings would need to be assessed, with reinforcement, as needed (if feasible at all);
- The presence of basalt rock for much of the route that might necessitate blasting to create a trench (and consequent safety and noise issues).
- In many locations, the presence of sheer rock cliffs on either side of the highway and the absence or near-absence of constructable shoulder area.
- Washington State Department of Transportation (WSDOT) would have to approve a blanket exception to the prohibition on the use of linear utilities within a state highway prism; while such exceptions are possible and within WSDOT's authority, there is no guarantee that the entire route would be granted an exception.
- The susceptibility of some stretches of the route to rockslides; WSDOT policy places priority on maintaining a safe highway, so that a rockslide could not only impede cable installation, but could require removal of a portion of the installed cable in order to restore the highway.
- The need to shut down a lane of the two-lane highway for cable installation, which almost certainly would require much or all of the work to be done at night.

Using a substantial portion of SR 14 would still require crossing of the Columbia River in two places in order to reach the interconnection points in Portland and The Dalles. Further, as a practical matter, any construction contractor with the experience and capability of performing the work would do so only on a time-and-materials basis due to the multiple uncertainties involved (WSDOT requirements, rock, force majeure events such as rockslides, lane restrictions, time of day restrictions, reinforcement of structures, etc.). It would be virtually impossible to estimate, much less guarantee, a cost or schedule for the work without including vast contingencies on both.

The Applicant acknowledges that the proposed alignment does include the use of a small portion of SR 14 (approximately 4 miles) as part of a 7.5-mile stretch of underground cable needed to bypass the Bonneville Lock and Dam. Based on the Applicant's affiliates' experience and on direct communication with WSDOT, the Applicant considers this short stretch of SR 14 to be free of significant obstacles and believes that the time required for the work can be conservatively

estimated at 6 months. The work required in this relatively small portion of SR 14 is in no way comparable to the work that would be required for more than 80 miles and multiple challenges and uncertainties that are virtually impossible to quantify or estimate.

Solar Development in Western Oregon and Washington

The Applicant believes that consideration of significant utility scale solar development in western Oregon and Washington to meet the requirements of HB2021 and the Clean Energy Transformation Act (CETA) is a largely speculative and unrealistic alternative to high-capacity transmission accessing utility scale solar and wind from east of the Cascades.

Community-based renewable energy (CBRE) facilities, while feasible and commendable, produce only very small amounts of energy in comparison to the rapidly growing need for new energy sources and associated transmission capacity. To illustrate, PGE's 2023 CEP-IRP includes an extensive discussion of CBREs and expresses strong support for them. Even so, only 155 MW of CBREs are assumed to be in place by 2030 (2023 CEP-IRP, Section 7.2.2.2) when calculating its additional transmission capacity need, which is estimated to be 1,658 MW by 2030. While PGE indicates a realistic prospect of growing CBREs post-2030, this is overwhelmed by PGE's projected additional transmission capacity needs of 4,568 MW by 2035 and 9,403 MW by 2040. Further, as quoted above in Section 7.1, PGE states that the results of its portfolio analysis demonstrate that current forecasts of transmission capacity are insufficient even when the entire available potential for CBREs are factored in.

Utility-scale solar facilities in western Oregon and Washington could certainly help meet growing energy needs, but the prospects for these on a scale sufficient to eliminate the need for new east-west transmission into the Portland metro load center are extremely remote. As a general illustration, BPA's interconnection queue shows that 86 percent of all proposed (but unbuilt) wind and solar facilities are located east of the Cascades – and these percentages include proposals for offshore wind. (The ratio without offshore wind is approximately 92 percent east to 8 percent west.) Currently, no utility-scale solar facility has been built west of the Cascades in Oregon, and only one such project (Muddy Creek in Linn County at 199 MW) has filed an NOI with the Oregon Department of Energy, compared with more than 4,000 MW of utility-scale solar east of the Cascades currently in construction or under review. The state's land use standards make it extremely difficult to permit utility scale solar facilities on the highest value farmland soils and it is unclear whether projects west of the Cascades could secure the necessary land use approvals, including an exception from Statewide Planning Goal 3 (Agricultural Lands). One of the reasons for the east-west differential is indicated in PGE's 2023 CEP-IRP, which considers four facilities at 75 MW each of new solar generation built by 2026. PGE calculates that the capacity factor for the one western facility (McMinnville) at 21.1 percent is significantly lower than for the remaining three (two in eastern Oregon, one in Nevada) at 26.7, 25.3, and 31.6 percent (2023 CEP-IRP, Section 8.1.7.2). This suggests that utility-scale solar in western Oregon is at a significant disadvantage in terms of cost and efficiency in comparison to potential solar resources east of the Cascades. In addition, due to south-north transmission constraints noted previously, large amounts of new utility-scale solar in western Oregon would still require new additional transmission capacity to reach the greater Portland area.

The potential for cost-effective utility scale solar in western Washington appears to be very limited. Currently, there are no western solar facilities proposed or under review by the Washington Energy

Facility Site Evaluation Council (WA EFSEC). The largest solar facility operating in Washington is 28 MW, in Lind, east of the Cascades. Other proposed facilities listed on the WA EFSEC website are all east of the Cascades and include two 80 MW projects in Yakima County and three projects totaling more than 1,000 MW in Benton County. If viable utility-scale solar projects are developed in eastern Washington, the existing South of Allston (SOA) transmission constraint would still pose an impediment to delivering that power into southwest Washington load centers such as Vancouver and the Portland metro area.

The Applicant has concluded that the potential for significant solar development to meet the regional requirements, including CBREs, in western Oregon and Washington is uneconomic relative to constructing transmission and accessing more economic utility-scale wind and solar east of the Cascades and unlikely to be able to meet the need for significant resource capacity expansion given existing land, transmission, and permitting constraints. The results of the Energy GPS Production Cost Analysis, included as Attachment 15, further support this conclusion.

Offshore Wind Development

The Applicant is familiar with previous efforts to evaluate and encourage offshore wind development along the Oregon coast. In February 2024, the federal Bureau of Ocean Energy Management (BOEM) published an Oregon Wind Energy Area Identification Memo that identified two Wind Energy Areas (WEAs) off the Oregon coast with the potential of siting approximately 3,000 MW of floating offshore wind installations. At the same time, BOEM published an NOI to prepare an environmental assessment for commercial wind lease issuance and site assessment activities related to the identified WEAs. Oregon, for its part, had become part of the BOEM Intergovernmental Renewable Energy Task Force to participate in activities related to offshore wind development.

PGE's 2023 CEP-IRP also addresses the potential for offshore wind by modeling 960 MW of offshore wind to be available in 2032, based on National Renewable Energy Laboratory studies (2023 CEP-IRP, Section 8.1.7.4). The studies and models are not related to specific projects proposed for development, and the time frame is simply an estimate for study purposes. PGE's estimated cost of such a development is approximately $3.5 million per installed MW, which is more than twice the cost per MW for onshore wind and about three times the cost of terrestrial solar. These estimates also do not account for development and construction costs that may be needed to reinforce and expand the transmission grid along the Oregon coast to be able to receive the output from offshore wind, nor additional transmission expansion needed to bring this capacity to load centers such as the greater Portland area. Given current market conditions, PGE's 2023 CEP-IRP Update delayed the availability of offshore wind in its modeling until 2036, but offshore wind was not selected as part of the preferred portfolio.

In addition, Oregon appears to have suspended its consideration of offshore wind development. In a September 27, 2024 letter to the Director of BOEM, Oregon Governor Tina Kotek announced Oregon's withdrawal from the BOEM Task Force and requested that BOEM "halt all current leasing activities off the coast of Oregon and terminate the current auction [of offshore wind lease areas]".

Given the extent of the multiple uncertainties related to offshore wind in Oregon (including quantity, location, timing, cost, federal action needed, environmental issues, and transmission), the Applicant does not consider offshore wind to be a comparable alternative to the Project, which can be

operational to help meet growing energy demands and public policy requirements in the 2030-2032 timeframe.

Energy Efficiency and Conservation

PGE's 2023 CEP-IRP includes extensive discussions of measures that would partially offset the need for additional generation and transmission resources over its "planning horizon" (the years 2023-2043). These include:

1. Distributed Energy Resources (DERs) (see 2023 CEP-IRP, Section 6.2.1)
2. Demand Response (see 2023 CEP-IRP, Section 6.2.2)
3. Energy Efficiency (see 2023 CEP-IRP, Section 6.2.3)
4. Community Based Renewable Energy, discussed above (see 2023 CEP-IRP, Chapter 7)

Measures that can be broadly categorized as "energy efficiency and conservation" include distributed energy storage and distributed generation (such as rooftop solar installations), as well as efforts to electrify buildings and vehicles. For electrification measures in particular, adoption of electrification requirements has the effect of increasing electricity demand over time (see 2023 CEP-IRP, Section 6.2.1, Figures 34 and 35).

PGE's 2023 CEP-IRP estimates the impact of rooftop solar installations as follows: "(T)he incremental energy impact from 2023 of customer-adopted solar in the Reference Case is estimated at approximately 25 megawatt-average (MWa) by 2030…By the end of the planning horizon, this is expected to double." (2023 CEP-IRP, Section 6.2.1). PGE's "high" case shows the impact to be approximately 30 MWa by 2030, and approximately 80 MWa by 2043.

Demand response measures include both technologies such as "smart" thermostats and programs such as time-of-use pricing and other strategies to reduce peak demands. PGE expects such measures to result in "achievable economic" impacts of 228 MW and 174 MW during summer and winter, respectively, by 2030 (the "high" case impacts are 282 MW in summer and 205 MW in winter).

PGE's 2023 CEP-IRP breaks down the impact of what it terms "cost effective" energy efficiency measures into industrial, commercial, and residential sectors and estimates savings in the range of approximately 30 MW per year in the near term (by 2030). The annual savings actually peaks around the 2032-2033 time frame and then declines over the next 10 years, since the cost-effective measures are assumed to be implemented more quickly. Even so, the cumulative impact of energy efficiency measures is estimated to be approximately 500 MW by 2043.

The key point is that in formulating its 2023 CEP-IRP and estimating its resource and transmission needs over its planning horizon, PGE *has already taken into account* what it believes to be realistic, cost-effective measures that can be broadly categorized as "energy efficiency and conservation" (including rooftop solar and other behind-the-meter generation and storage, demand response, and energy efficiency). Even assuming arbitrarily that PGE's "reference case" impacts are significantly understated and should be doubled, the results would not come close to offsetting the estimated additional transmission needs of 1,658 MW, 4,568 MW, and 9,043 MW by 2030, 2035, and 2040, respectively.

Recommendations of CRITFC's 2022 Energy Vision

The Applicant also considered alternatives based on recommendations in the Energy Vision for the Columbia River Basin (Energy Vision), published in 2022 by the Columbia River Inter-Tribal Fish Commission (CRITFC). The Energy Vision is included as Attachment 17 and the Applicant fully supports the four goals stated in that document (page 6):

- Create a regional energy portfolio that protects and enhances environmental quality, treaty protected resources, and supports the restoration of Columbia Basin's fish and wildlife to healthy and harvestable population levels.
- Prevent new and reduce ongoing damage to Columbia River Basin resources, including fish, wildlife, water quality, and tribal cultural resources, by recognizing the relationships and interdependencies of natural and built systems including the Northwest's energy system.
- Provide increased protection for both fish and wildlife and utility customers against unanticipated events, such as drought, fire, and market aberrations while providing an adequate, economical, and reliable electric supply.
- Mitigate climate change impacts to protect Northwest ecosystems by replacing fossil-fuel electric generation and reducing the reliance on fossil-fuels for power, transportation, and other uses.

Moreover, the Applicant believes that the Project is consistent with the 43 recommendations in the Energy Vision. Measures to reduce peak loads, increase energy storage, and maximize energy efficiency are fundamental to energy plans and policies throughout the Pacific Northwest. As discussed above, PGE has addressed many such measures in its 2023 CEP-IRP and has concluded that even when those measures it believes to be realistic and cost-effective are accounted for, the growing need over its planning horizon for additional transmission capacity is in the thousands of MW. Even assuming a doubling or tripling of PGE's projections of these measures does not approach the future resource or transmission needs.

Certain Energy Vision recommendations align directly with one of the main objectives of the Project, which is to create a 1,100-MW pathway for energy access from constrained generation resources and neighboring power systems to reach the growing energy load in the greater Portland area and the Oregon and Washington regions. Certain Energy Vision includes recommendations to reduce greenhouse gases (22), pursue wind power development (24), promote utility scale solar energy (25), and reduce the use of fossil fuels (40).

The Applicant also acknowledges the Energy Vision recommendations that directly support the protection and enhancement of fish and wildlife in the Columbia River Basin. As is shown in the Fish and Wildlife Habitat Exhibit and the Threatened and Endangered Species Exhibit of this application, the Project, as proposed, will minimize impacts to fish and wildlife populations. Impacts of Project construction, both in the river and on land, will be minor, temporary, and capable of being mitigated to the extent necessary. Project operation will require two converter stations occupying approximately 5 acres each, located in areas of existing compatible uses. Project operation does not require emissions into the atmosphere or discharges into water or onto the land. Consumption of water is negligible, as are quantities of waste and wastewater.

The Applicant also acknowledges Energy Vision Recommendations 36, 37, and 38, which are directly related to transmission. Recommendation 36, in particular, calls for solutions that "minimize transmission and distribution expansions." Given the demonstrated need for new transmission, either as quantified by PGE or in BPA's 2023 TSEP study, to meet reliability and clean energy goals, this exhibit describes how the proposed Project would provide a direct east-to-west path into the greater Portland area (Harborton substation) without the need to construct or expand additional south-north transmission to overcome existing constraints on the NOPE flowgate. Further, the proposed project eliminates or minimizes many of the negative or objectionable impacts associated with traditional overhead transmission, including visual impacts; impacts to terrestrial habitat, vegetation, and species; impacts to directly affected or adjacent property owners; and increased risk of wildfires.

OAR 345-023-0030(4)(h)

(h) The earliest and latest expected in-service dates of the facility and a discussion of the circumstances of the energy supplier, as defined in OAR 345-001-0010, that determine these dates.

RESPONSE

Current estimates based on the Applicant's updated assessment of siting, permitting, regulatory approvals, the terms of any resulting joint construction agreements, and other conditions and factors conclude the Project is expected to be in service during the 2030-2032 timeframe. As currently projected, the early completion date would be mid-2030; the late completion date would be late 2032. This takes into consideration a 2-3 year permitting timeline and 3-4 year construction timeline.

4 Conclusions

Table 6 identifies the location within the application for site certificate of the information responsive to the need standard for non-generating facilities, OAR 345-0023-0005, the need standard for the least-cost plan rule (OAR 345-023-0020), the need standard for the system reliability rule (OAR 345-023-003), the application submittal requirements in OAR 345-021-0000(7), and the relevant Project Order provisions.

Table 6. Compliance Requirements and Relevant Cross-References

Requirement	Location
OAR 345-021-0000(7)	
If the proposed facility is a non-generating facility for which the applicant must demonstrate need under OAR 345-023-0005, in addition to the application for a site certificate described in OAR 345, divisions 21 through 24, the applicant must submit to the Department two copies of each energy resource plan or combination of plans on which the applicant relies to demonstrate need under OAR 345-023-0020, unless the applicant chooses to incorporate copies of the plans as part of the application for a site certificate. The applicant must submit the plans to the Department with the site certificate application. The Department may not find the site certificate application to be complete before receiving copies of the plans. The plans described in this section are part of the decision record for the Department's proposed order, described in OAR 345-015-0230.	Section 2.2

Requirement	Location
OAR 345-023-0005	
This division applies to non-generating facilities as defined in Oregon Revised Statute (ORS) 469.503(2)(e), except non-generating facilities that are related or supporting facilities. To issue a site certificate for a facility described in sections (1) through (3), the Council must find that the applicant has demonstrated the need for the facility. The Council may adopt need standards for other non-generating facilities. This division describes the methods the applicant shall use to demonstrate need. In accordance with ORS 469.501(1)(L), the Council has no standard requiring a showing of need or cost-effectiveness for generating facilities. The applicant shall demonstrate need: (1) For electric transmission lines under the least-cost plan rule, OAR 345-023-0020(1), or the system reliability rule for transmission lines, OAR 345-023-0030, or by demonstrating that the transmission line is proposed to be located within a "National Interest Electric Transmission Corridor" designated by the U.S. Department of Energy under Section 216 of the Federal Power Act;	Section 2.2
OAR 345-023-0020(1-2)	
(1) The Council shall find that the applicant has demonstrated need for the facility if the capacity of the proposed facility or a facility substantially similar to the proposed facility, as defined by OAR 345- 001-0010, is identified for acquisition in the short-term plan of action of an energy resource plan or combination of plans . . . . (2) The Council shall find that a least-cost plan meets the criteria of an energy resource plan described in section (1) if the Public Utility Commission of Oregon has acknowledged the least cost plan.	Section 2.3 Attachment 1, Attachment 2, Attachment 6, Attachment 7
OAR 345-023-0020(3)	
(3) If the applicant chooses to demonstrate need for the proposed facility under OAR 345-023-0020(1), the least-cost plan rule, they must submit the following additional information in their application:	--
(a) Identification of the energy resource plan or combination of plans on which the applicant relies to demonstrate need;	Section 3.1
(b) The name, address and telephone number of the person responsible for preparing each energy resource plan identified in subsection (a);	Section 3.1
(c) For each plan reviewed by a regulatory agency, the agency's findings and final decision, including:	Section 3.1
(A) For a plan reviewed by the Oregon Public Utility Commission, the acknowledgment order; or	Section 3.1
(B) For a plan reviewed by any other regulatory agency, a summary of the public process including evidence to support a finding by the Council that the agency's decision process included a full, fair and open public participation and comment process as required by OAR 345-023-0020(1)(L), and the location of and means by which the Department can obtain a complete copy of the public record;	Section 3.1
(d) Identification of the sections of the short-term action plan that call for the acquisition of the proposed facility or, as defined in OAR 345-001-0010, a facility substantially similar to the proposed facility;	Section 3.1
(e) The attributes of the proposed facility that qualify it as one called for in the short-term action plan of the energy resource plan or combination of plans identified in subparagraph (i) or a demonstration that, as defined in OAR 345-001-0010, a facility substantially similar to the proposed facility is called for in the plan.	Section 3.1

Requirement	Location
OAR 345-023-0020(4)	
(4) If the applicant chooses to demonstrate need for the proposed facility under OAR 345-023-0020(1), the least-cost plan rule, and relies on an energy resource plan not acknowledged by the Public Utility Commission of Oregon, they must submit the following additional information: (a) The names, addresses and telephone numbers of members of any public advisory groups that participated in the preparation and review of each plan identified in (3)(c); (b) A discussion of how the plan or combination of plans conforms to the standards in OAR 345-023-0020(1)(a) through (L) including citations to relevant portions of the plan documents or other supporting evidence; (c) The expected annual emissions in tons of nitrogen oxides, PM-10 particulate, sulfur dioxide, carbon dioxide and mercury and a discussion of other environmental impacts, as compared to resources in the applicable energy resource plan; (d) In addition to the information described in (b) and (c), if the applicant chooses to demonstrate need for a proposed natural gas pipeline or storage facility for liquefied natural gas under OAR 345-023-0020(1), the least-cost plan rule, and relies on an energy resource plan not acknowledged by the Public Utility Commission of Oregon, the applicant must include the information described in OAR 345-023-0040(3) if the energy resource plan or combination of plans does not contain that information. If the energy resource plan or combination of plans contains the information described in OAR 345-023-0040(3), the applicant must provide a list of citations to the sections of the energy resource plan that contain the information; (e) In addition to the information described in (b) and (c), if the applicant chooses to demonstrate need for a proposed electric transmission line under OAR 345-023-0020(1), the least-cost plan rule and relies on an energy resource plan not acknowledged by the Public Utility Commission of Oregon, the applicant must include the information described in OAR 345-023-0030(4) if the energy resource plan or combination of plans does not contain that information. If the energy resource plan or combination of plans contains the information described in OAR 345-023-0030(4), the applicant must provide a list of citations to the sections of the energy resource plan that contain the information.	Not applicable
OAR 345-023-0030(1-3)	
The Council shall find that the applicant has demonstrated need for an electric transmission line that is an energy facility under the definition in ORS 469.300 if the Council finds that: (1) The facility is needed to enable the transmission system of which it is to be a part to meet firm capacity demands for electricity or firm annual electricity sales that are reasonably expected to occur within five years of the facility's proposed in-service date based on weather conditions that have at least a 5 percent chance of occurrence in any year in the area to be served by the facility; (2) The facility is consistent with the minimum operating reliability criteria contained in the Western System Coordinating Council Bulk Power Supply Program 1997-2007, dated April 1, 1998, as it applies either internally or externally to a utility system; and (3) Construction and operation of the facility is an economically reasonable method of meeting the requirements of sections (1) and (2) compared to the alternatives evaluated in the application for a site certificate.	Section 2.4, Attachment 3
OAR 345-023-0030(4)	
(4) If the applicant chooses to demonstrate need for a proposed electric transmission line under OAR 345-023-0030, they must submit the following additional information:	--

Requirement	Location
a) Load-resource balance tables for the area to be served by the proposed facility. In the tables, the applicant must include firm capacity demands and existing and committed firm resources for each of the years from the date of submission of the application to at least five years after the expected in-service date of the facility;	Section 3.2, Attachment 3
(b) Within the tables described in (a), a forecast of firm capacity demands for electricity and firm annual electricity sales for the area to be served by the proposed facility. The applicant must separate firm capacity demands and firm annual electricity sales into loads of retail customers, system losses, reserve margins and each wholesale contract for firm sale. In the forecast, the applicant must include a discussion of how the forecast incorporates reductions in firm capacity demand and firm annual electricity sales resulting from:	Section 3.2, Attachment 3
(A) Existing federal, state or local building codes, and equipment standards and conservation programs required by law for the area to be served by the proposed facility;	Section 3.2
(B) Conservation programs provided by the energy supplier, as defined in OAR 345-001-0010;	Section 3.2
(C) Conservation that results from responses to price; and	Section 3.2
(D) Retail customer fuel choice;	Section 3.2
(c) Within the tables described in (a), a forecast of existing and committed firm resources used to meet the demands described in (b). The applicant must include, as existing and committed firm resources, existing generation and transmission facilities, firm contract resources and committed new resources minus expected resource retirements or displacement. In the forecast, the applicant must list each resource separately;	Section 3.2, Attachment 3
(d) A discussion of the reasons each resource is being retired or displaced if the forecast described in (c) includes expected retirements or displacements;	Section 3.2
(e) A discussion of the annual capacity factors assumed for any generating facilities listed in the forecast described in (c);	Section 3.2, Attachment 3
(f) A discussion of the reliability criteria the applicant uses to demonstrate the proposed facility is needed, considering the load carrying capability of existing transmission system facilities supporting the area to be served by the proposed facility;	Section 3.2, Attachment 3
(g) A discussion of reasons why the proposed facility is economically reasonable compared to the alternatives described below. In the discussion, the applicant must include a table showing the amounts of firm capacity and firm annual electricity available from the proposed facility and each alternative and the estimated direct cost, as defined in OAR 345-001-0010, of the proposed facility and each alternative. The applicant must include documentation of assumptions and calculations supporting the table. The applicant must evaluate alternatives to construction and operation of the proposed facility that include, but are not limited to:	Section 3.2, Table 5
(A) Implementation of cost-effective conservation, peak load management and voluntary customer interruption as a substitute for the proposed facility;	Section 3.2
(B) Construction and operation of electric generating facilities as a substitute for the proposed facility;	Section 3.2
(C) Direct use of natural gas, solar or geothermal resources at retail loads as a substitute for use of electricity transmitted by the proposed facility;	Section 3.2
(D) Adding standard sized smaller or larger transmission line capacity;	Section 3.2
(h) The earliest and latest expected in-service dates of the facility and a discussion of the circumstances of the energy supplier, as defined in OAR 345-001-0010, that determine these dates.	Section 3.2

Requirement	Location
First Amended Project Order 2025-04-24, Section III.P	
Under OAR 345-021-0010(1)(n)(A) an application for a transmission line must include the applicant's election to meet the Need Standard either under the least-cost plan rule, OAR 345-023-0020(1), the system reliability rule, OAR 345-023-0030, or by demonstrating that the transmission line is proposed to be located within a National Interest Electric Transmission Corridor designated under Section 216 of the Federal Power Act. In the Notice of Intent (NOI), the applicant stated that it intends to demonstrate need for the proposed facility under the system reliability rule. The applicant subsequently indicated that it will demonstrate the need for the facility under both the least-cost plan rule and the system reliability rule. The applicant must inform the Department if this election changes prior to the submission of the preliminary Application for Site Certificate.	Section 2.2, Section 2.3, and Section 2.4

5 References

Bonneville Power Administration (BPA). 2023. Transmission System Expansion Plan (TSEP). 2023 Cluster Study Report. December 21, 2023.

Attachment 1. Evolving Grid – Update on Transmission Activities, December 4, 2024

Evolving Grid

Update on Transmission Activities

December 4, 2024

Rates Hearing Room & Webex

Ex Parte Reminder

We want to make sure that everyone participating today is aware that the BP-26, TC-26, and public rate design methodology proceedings are underway and that the procedural rules for the proceedings prohibit "*ex parte*" communications with BPA about the merits of the issues in those proceedings. That means that BPA will not be talking about issues in BP-26, TC-26 or PRDM today and cannot listen to comments about the issues. Please direct any comments on issues in BP-26, TC-26, or PRDM to the proceedings themselves.

Agenda

Time	Topic	
9:00 to 9:05	Opening Remarks & Safety Moment	Katie Sheckells
9:05 to 9:15	Welcoming Remarks	Richard Shaheen
9:15 to 9:30	Environmental Compliance	Katey Grange & Kevin Cannell
9:30 to 11:30	Transmission Expansion Overview & Discussion • 2024 Transmission Plan • Bifurcated Commercial Model • Evolving Grid Projects 1.0 & 2.0 Q&A	Team
11:30 to 1	**LUNCH**	
1:00 to 1:30	Customer Reliability Improvement Service Program (CRISP)	Victor Hitchens
1:30 to 2:00	Customer Self-build	Katie Sheckells & Kevlyn Baker
2:00 to 2:25	WestTEC Update	Ravi Aggarwal & Crystal Ball
2:25 to 2:30	Closing Remarks & Next Steps	Katie Sheckells
End of Meeting		

Safety Moment: Winter Driving

The Objective of BPA's Evolving Grid Initiative

A variety of factors are creating a need for a transformational shift in the Transmission industry. Bonneville Transmission wants to raise awareness of recent efforts and initiatives, those underway and yet to come, and what customers and the region can expect in the future as we navigate the changing landscape.

Environmental Compliance

Laws and Requirements - Bonneville Power Administration

What is NEPA (National Environmental Policy Act)?

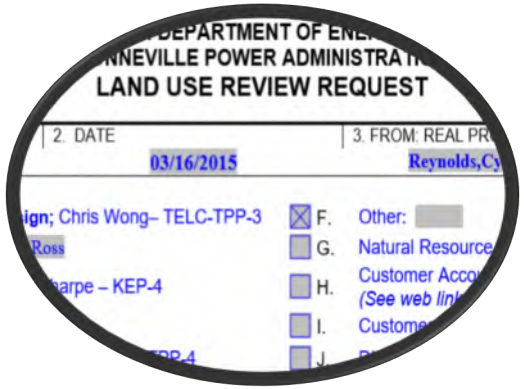
- Requires assessment of environmental effects of projects (proposed action) and to disclose the effects to the public
- Requires analysis *before* decisions are made and before actions are taken
- Includes public outreach and analysis availability
- Involves coordinating compliance with other environmental laws (including consultations and permitting)
- It is a process, not a permit

Examples of Transmission Actions Requiring NEPA

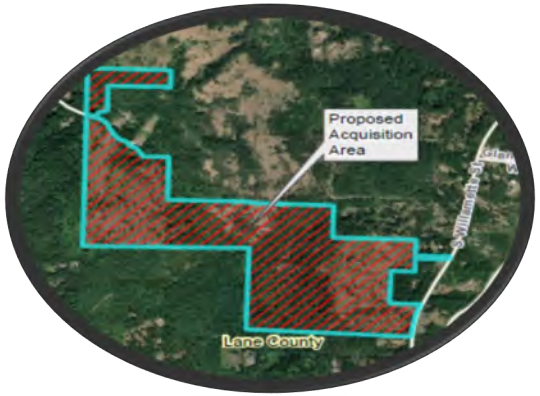
Capital

Vegetation Maintenance

Maintenance



Authorizations

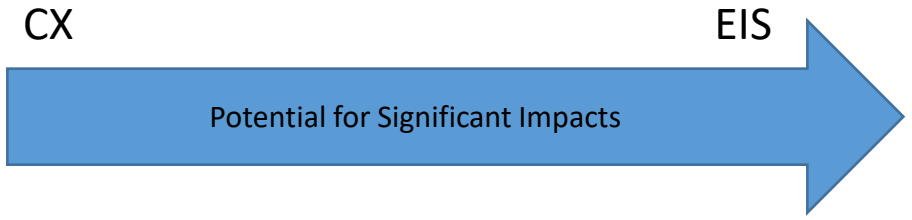


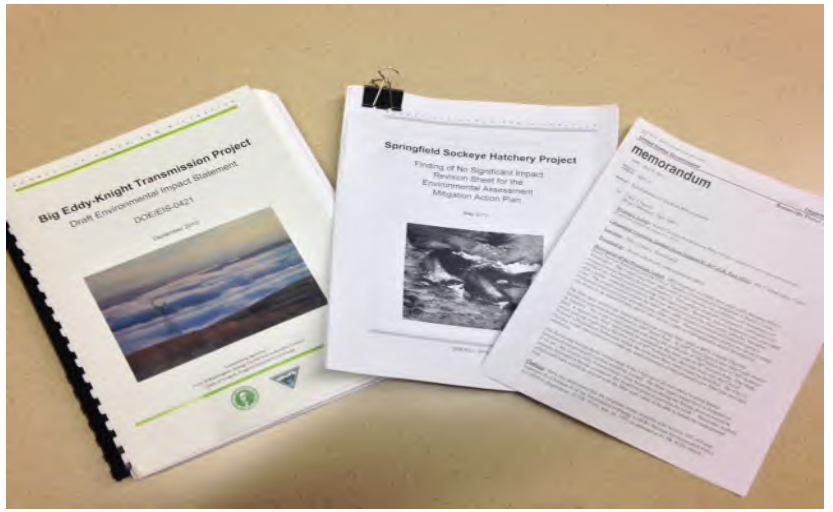
Acquisition & Disposal

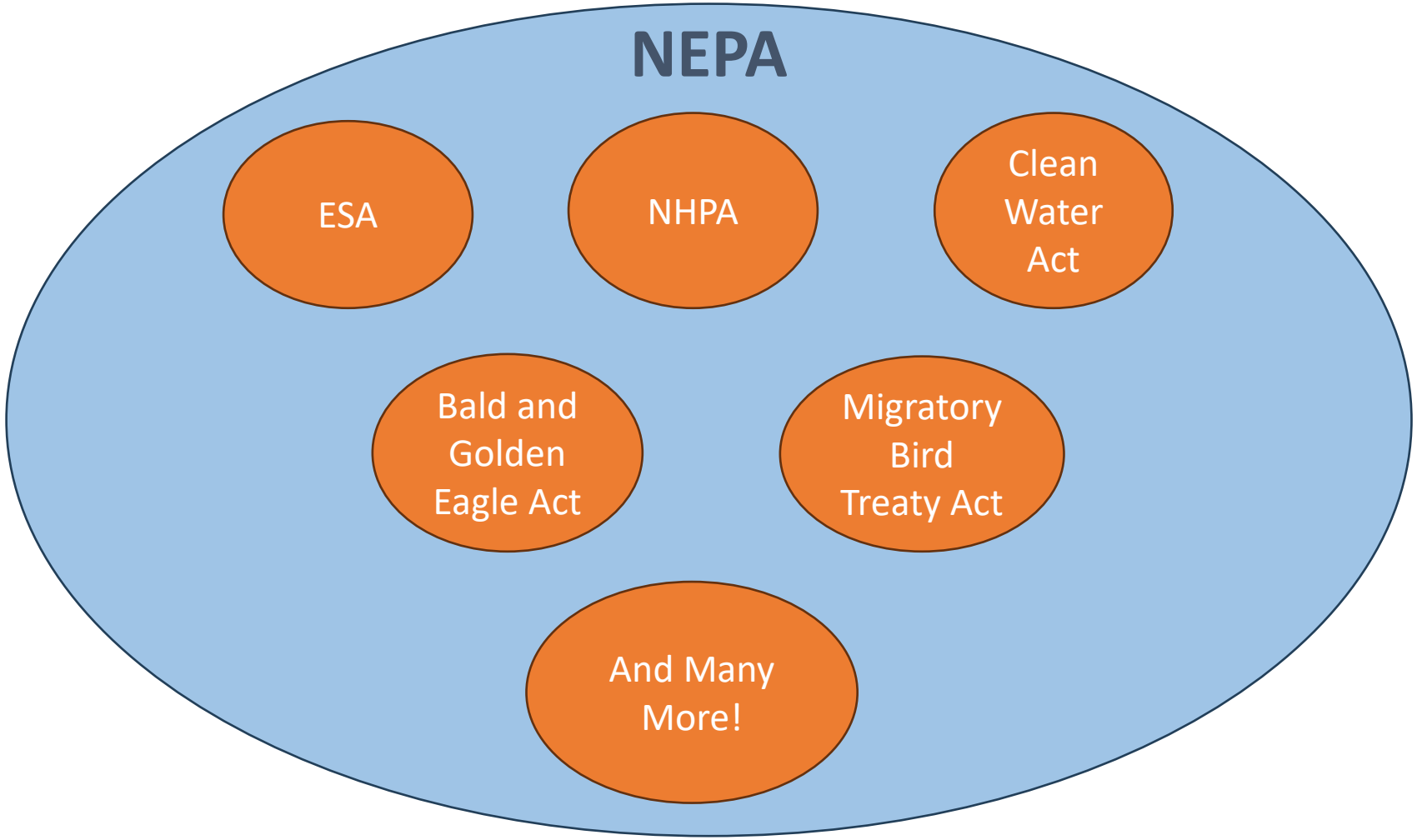
NEPA is required for actions taken by all BPA's business lines.

Types of NEPA Documents

- Categorical Exclusion (CX)
- Environmental Assessment (EA)
- Environmental Impact Statement (EIS)







NEPA integrates the review and compliance requirements of other laws

National DOE NEPA Updates

- Categorical Exclusion B4.13 Upgrading and Rebuilding Existing Powerlines – removal of line mile limitations
- Grid Deployment Office (GDO) and Coordinated Interagency Transmission Authorizations and Permits Program (CITAP)

National Historic Preservation Act (1966)

SECTION 106: The head of any Federal agency having direct or indirect jurisdiction over a proposed Federal or federally assisted undertaking in any State and the head of any Federal department or independent agency having authority to license any undertaking shall, prior to the approval of the expenditure of any Federal funds on the undertaking or prior to the issuance of any license, as the case may be, *take into account the effect of the undertaking on any district, site, building, structure, or object that is included in or eligible for inclusion in the National Register.* The head of any such Federal agency shall afford the Advisory Council on Historic Preservation established under Title II of this Act a reasonable opportunity to comment with regard to such undertaking.

Section 106

BPA must take into account the effects of its undertakings on historic properties and afford the Advisory Council on Historic Preservation opportunity to comment.

Historic properties = districts, sites, buildings, structures or objects that are eligible for inclusion in the National Register of Historic Places.

Four steps (36 CFR 800)

1) Initiate consultation with consulting parties (Tribes, State Historic Preservation Officer, etc.)
   - Define area of potential effects

2) Identify historic properties – Potential methods include research, interviews, and fieldwork, etc.

3) Assess effects and make determination of effect
   - No historic properties affected
   - No adverse effect to historic properties
   - Adverse effect

4) Resolve adverse effects – avoid, minimize, or mitigate adverse effects
   - Memorandum of Agreement or Programmatic Agreement

Overview of Transmission Projects

2024 Transmission Plan Portfolio

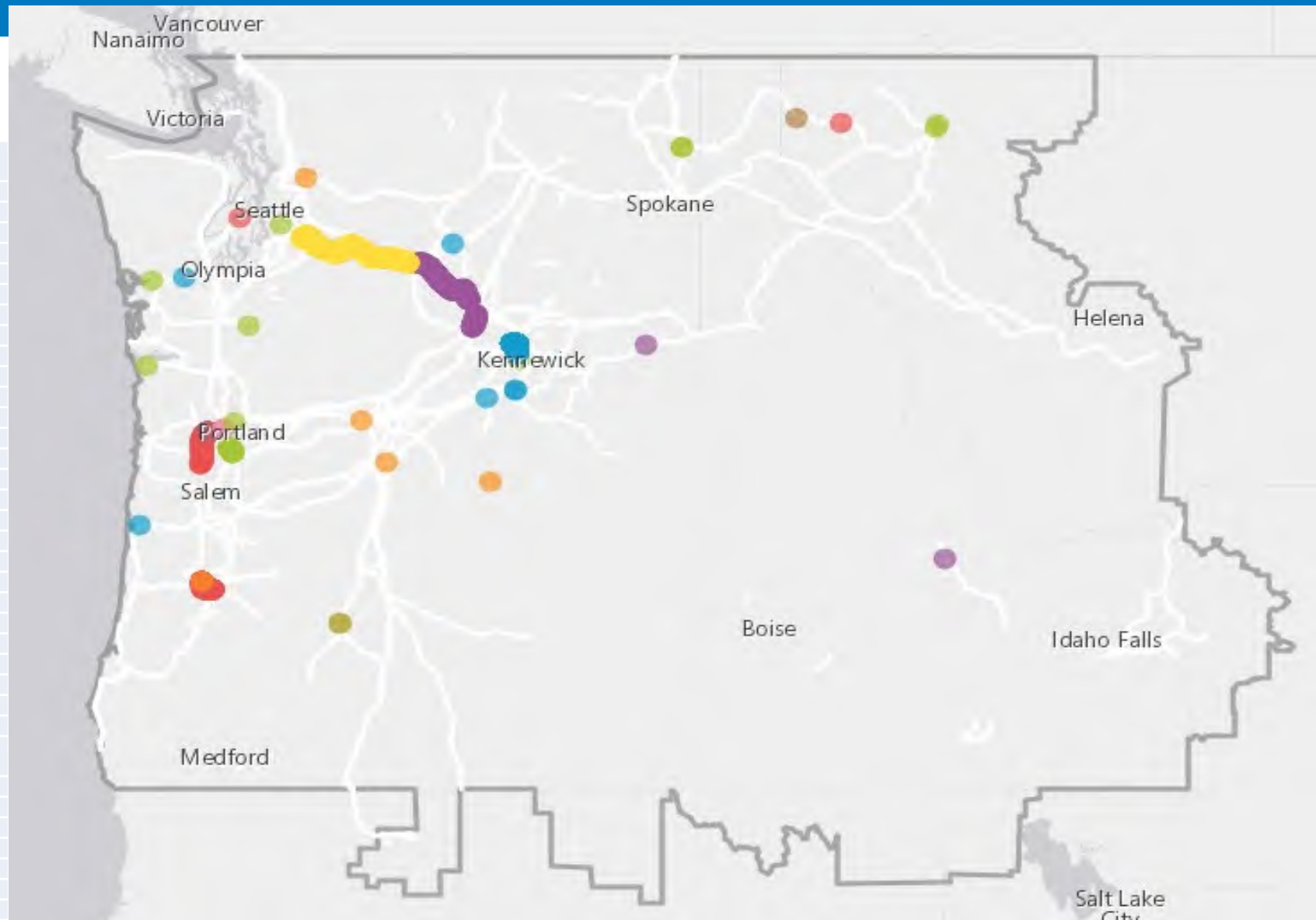
Bifurcated Commercial Model

Evolving Grid Project 1.0 & 2.0 Portfolios

2024 Transmission Plan

- 10-Year Planning Horizon. 35 Projects in all phases of development.

Expected Energization	Project
2025	CENTRAL OREGON COAST O&M FLEX/SUSTAIN (TOLEDDO-WENDSON-SANTIAM-TAHKENITCH)
2025	FOREST GROVE-MCMINNVILLE-1 115kV LINE UPGRADE
2025	LONGHORN 500/230 KV SUBSTATION l0482
2025	MCNARY 230KV SECTION BAY ADDITION L0481
2025	MCNARY-PATTERSON TAP 115KV LINE
2025	NORTHERN MID-COLUMBIA PROJECT (BPA-CHELAN-DOUGLAS-GRANT)
2025	RED MOUNTAIN-HORN RAPIDS 115KV TRANSMISSION LINE RECONDUCTOR
2025	SOUTH ELMA-SATSOP PARK-1 LINE REMOVE IMPAIRMENTS
2026	CARLTON AREA UPGRADES
2026	KITSAP CAP RELOCATION AND BREAKER REPLACEMENT
2026	LAPINE SUBSTATION UPGRADE TSEP 2016
2026	LIBBY POWER HOUSE 1 AND 2 REDUNDANT TRANSFER TRIP
2026	LOOKOUT POINT-ALVEY-1 AND ALVEY-2: 115KV LINE TRANSFER TRIP ADDITION
2026	TROUTDALE 230KV SERIES BUS SECTIONALIZING BREAKER
2027	BELL-BOUNDARY 230 kV No. 1 (SACHEEN) LINE UPGRADE.
2027	CONKELLEY SUBSTATION RETIREMENT
2027	HIGH SIDE BREAKER AND GEAR ASSOCIATED WITH THE CLATSOP TRANSFORMER REPLACEMENT
2027	LAPINE: UPGRADE TSEP 2016 - TRANSFORMER ADDITION
2027	MAPLE VALLEY 230 kV SHUNT REACTOR
2027	PEARL-SHERWOOD-MCLOUGHLIN UPGRADE TSEP 2021
2027	RICHLAND-STEVENS DRIVE 115KV LINE
2027	SILVER CREEK BUS SECTIONALIZING & TRANSFORMER PCB ADDITION
2027	SOUTH TRI-CITIES REINFORCEMENT WEBBER CANYON G0558
2027	ST. JOHNS 230/115 kV LOW-SIDE LINE SECTION REMOVE IMPAIRMENTS
2027	UPGRADE ABERDEEN TAP TO SATSOP PARK-COSMOPOLIS-1: 115KV (TPP)
2028	ALVEY-DILLARD TAP 115KV LINE REBUILD
2028	BUCKLEY AIR INSULATED SUBSTATION (FUTURE)
2028	KEELER 230 kV BUS SECTIONALIZING BREAKER ADDITION (KEELER EQUIPMENT REPLACEMENTS, BREAKER ADDITION & NEW HORIZON TERMINATION (L0452))
2028	MONROE-NOVELTY 230KV LINE UPGRADE
2028	MORROW FLAT 230 KV SHUNT REACTOR
2028	QUENETT CREEK SUBSTATION (L0380)
2029	KEELER 500KV EXPANSION AND TRANSFORMER ADDITION
2030	SCHULTZ-RAVER RECONDUCTOR AND PAUL CAPACITOR
2030	SCHULTZ-RAVER: SERIES CAPS TSEP 2020
2032	TROY SUBSTATION EXPANSION PROJECT



Bifurcated Commercial Model

How a Commercial Upgrade Becomes an Evolving Grid Project (EGP)

Disclaimers

- Construction of transmission and transmission expansion projects are subject to the Administrator's determination and completion of environmental compliance.
  - This includes commercially driven projects in the TSR Study and Expansion Process (TSEP)
- This discussion is to share as much information as possible without placing limits on the ability of the Administrator to respond to the needs of the region and the dynamic industry landscape.
- This is the process, decisions, and timelines BPA envisions, but any of these could change as needs arise.

Characteristics that may Differentiate Projects

Regionally Needed Projects (RNP)

1. Necessary main grid reinforcement regardless of specific generator locations
2. Critical for load service
3. Excellent economics (supports BPA financial ability to support other activities)
4. Provides transmission service for substantial MW of "mature" generation
5. Supports critical regional BAA resource diversity
6. Also necessary for NT load growth, LLI, or GI needs
7. Avoids future (within 10-year horizon) reliability need/costs
8. Supports adjacent transmission provider systems
9. Regional level support of public policy

Customer Needed Projects(CNP)

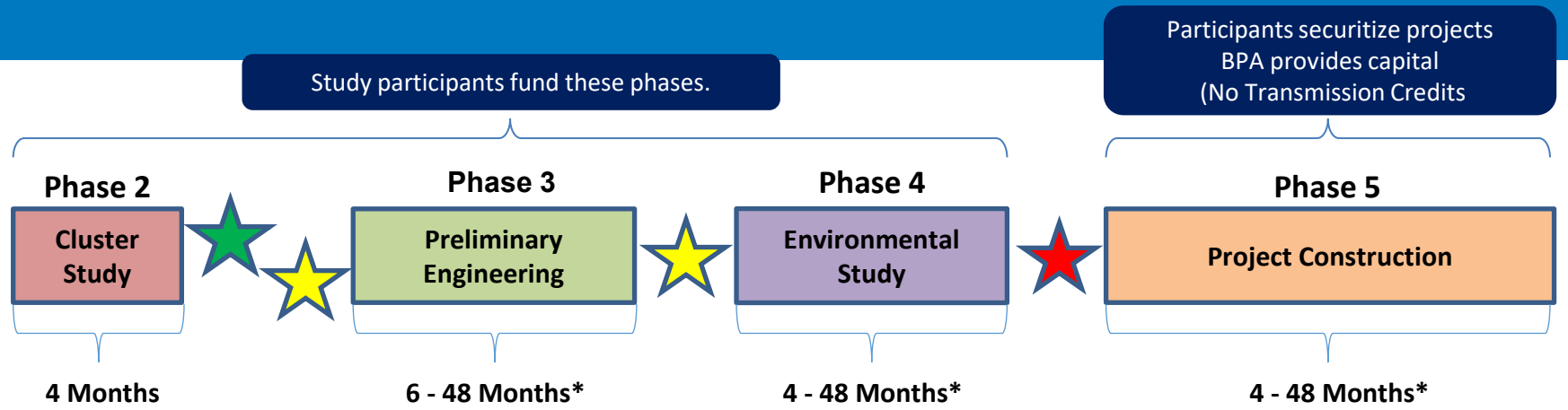
1. Needed only by one or a few customers
- **a.** Not likely a main grid expansion
- **b.** Withdrawal of TSR(s) creates risk of stranded asset to BPA
- **c.** Limited potential for hop-on TSRs

2. Project economics require substantial customer commitment (MWs or terms) to avoid potential incremental rate
3. GI projects requiring transmission service associated with the project not very mature
4. Does not meet characteristics of a RNP

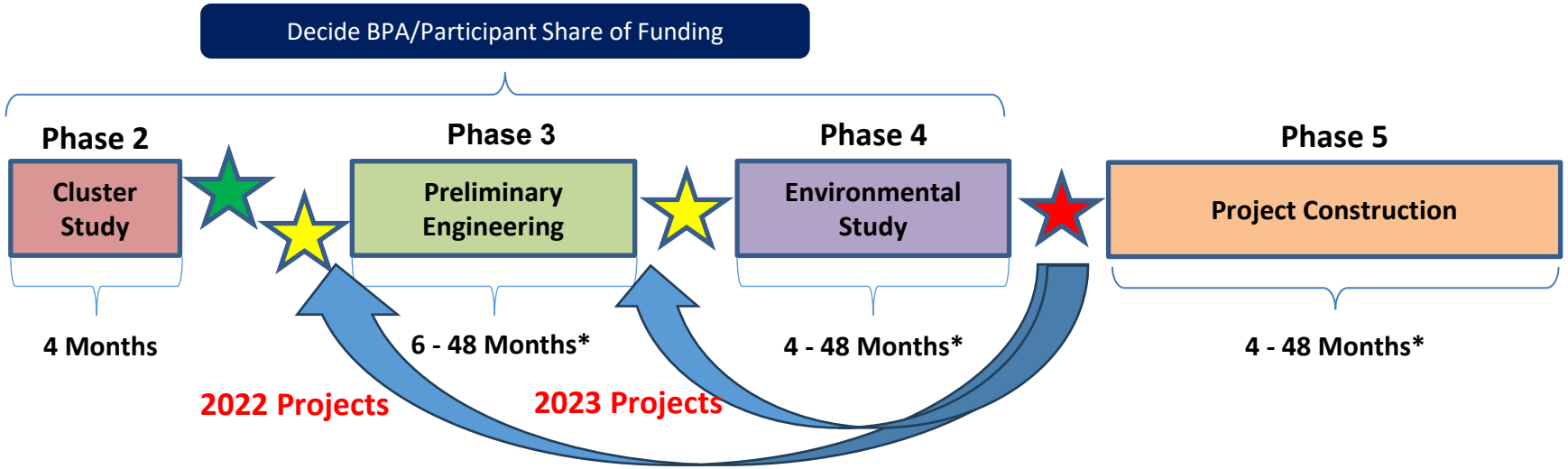
For each project, the characteristics and their importance is at the discretion of the BPA Administrator.

Decision Timing

Track A
Customer Needed Expansion Projects (TSEP Status Quo)



Track B
Regionally Needed Expansion Projects



Key Takeaway: Decisions of critical importance to regional stakeholders for the 2023 TSEP CS Regionally Needed Projects will occur late in the Preliminary Engineering Phase.

Project Decisions for EGP 1.0

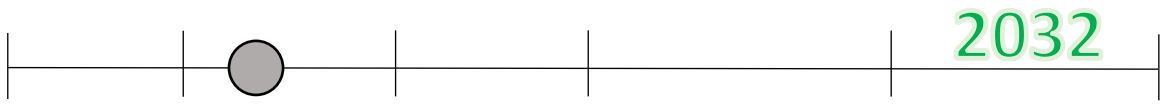
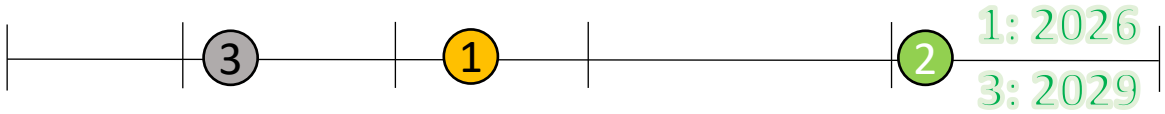
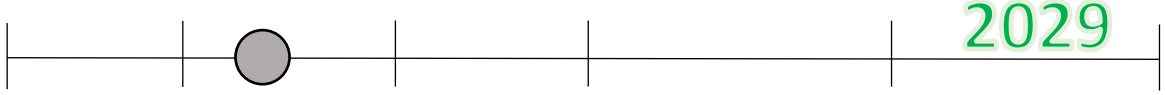
- Extent of customer funding for Preliminary Engineering/Scoping (0 – 100%)
- Extent of customer funding for Environmental Study and Design (0 – 100%)
- Extent of required securitization (0 – 100% of direct project costs, assigned to TSRs on a per MW share basis)
- Announcing an initial intention to make BPA capital funding available, subject to environmental compliance can be done early, or at a point up to post-completion of NEPA; must be done prior to offer of contracts.
- Embed project costs for the initial rate proposal.

EGP 1.0* Decisions	
Item	**Decision**
Preliminary Engineering Costs	Customer Pays 100%
Environmental Review	Customer Pays 100%
Securitization	Not Required
BPA Capital Funding	Early BPA Capital if Needed
Embed Costs for Initial Proposal	Yes

**Treatment of EGP 2.0 projects will not be determined until they complete Scoping.*

EGP 1.0 & 2.0 Portfolio Update

- On Oct 17, BPA presented a significant update on the potential for an additional portfolio of major transmission projects (upgrades and expansion).
  - EGP 1.0 consists of 10 projects of over $2 billion
  - EGP 2.0 consists of 13 projects of over $3 billion
- During the public meeting, several questions and clarifications were asked and BPA is providing answers to those questions and welcomes further discussion.
  - Oct 17 consolidated list of questions and clarifications
- Prior to the open discussion on the Q&A, BPA would like to provide some additional updates and clarifications on the status of its queues and the bifurcated model.

EGP 1.0 Project	Initiation → Scoping → Design → Construction → Closeout	Next Milestone
Cross Cascades North Upgrades: Multiple projects		1. Schultz-Raver 500 kV line upgrade in Scoping. 2. Paul 500 kV substation in Scoping 3. Olympia 230 kV substation in Scoping
Big Eddy-Chemawa Line Upgrade		Project started Scoping this fall and planned to finish in summer 2025.
Portland Area: Multiple projects		1. Pearl-Sherwood-Mcloughlin: Project is in Design. 2. Keeler-Horizon#2: Project is Energized. 3. Keeler Transformer Addition: Project is in Scoping.
Chehalis-Covington Line Upgrade		Project has finished Scoping and starting Design in early 2025.
Ross-Rivergate Line Upgrade		Project started Scoping this fall and planned to finish in late spring 2025.
Rock Creek-John Day Line Upgrade		Project has completed significant scoping and planned to finish in spring 2025.

EGP 1.0 Project

Initiation | Scoping | Design | Construction | Closeout

Next Milestone

Six Mile Canyon Substation	2027	Project is nearing completion of Scoping. A feasible site has been selected. Longest Lead Material has been placed on order.
Bonanza Substation	2028	Project started Scoping this fall and planned to finish in summer 2025.
La Pine-Bonanza Line	2030	Plan of Service has been completed and Scoping planned to start in early 2025.
Buckley Substation Rebuild	2028	Project is in Design.

BONNEVILLE POWER ADMINISTRATION

Evolving Grid Projects 1.0 & 2.0

Evolving Grid 1.0

1	Cross Cascades North Upgrades • Schultz-Raver 500 kV Line Upgrade • Paul 500 kV Substation Upgrade • Olympia 230 kV Substation Upgrade
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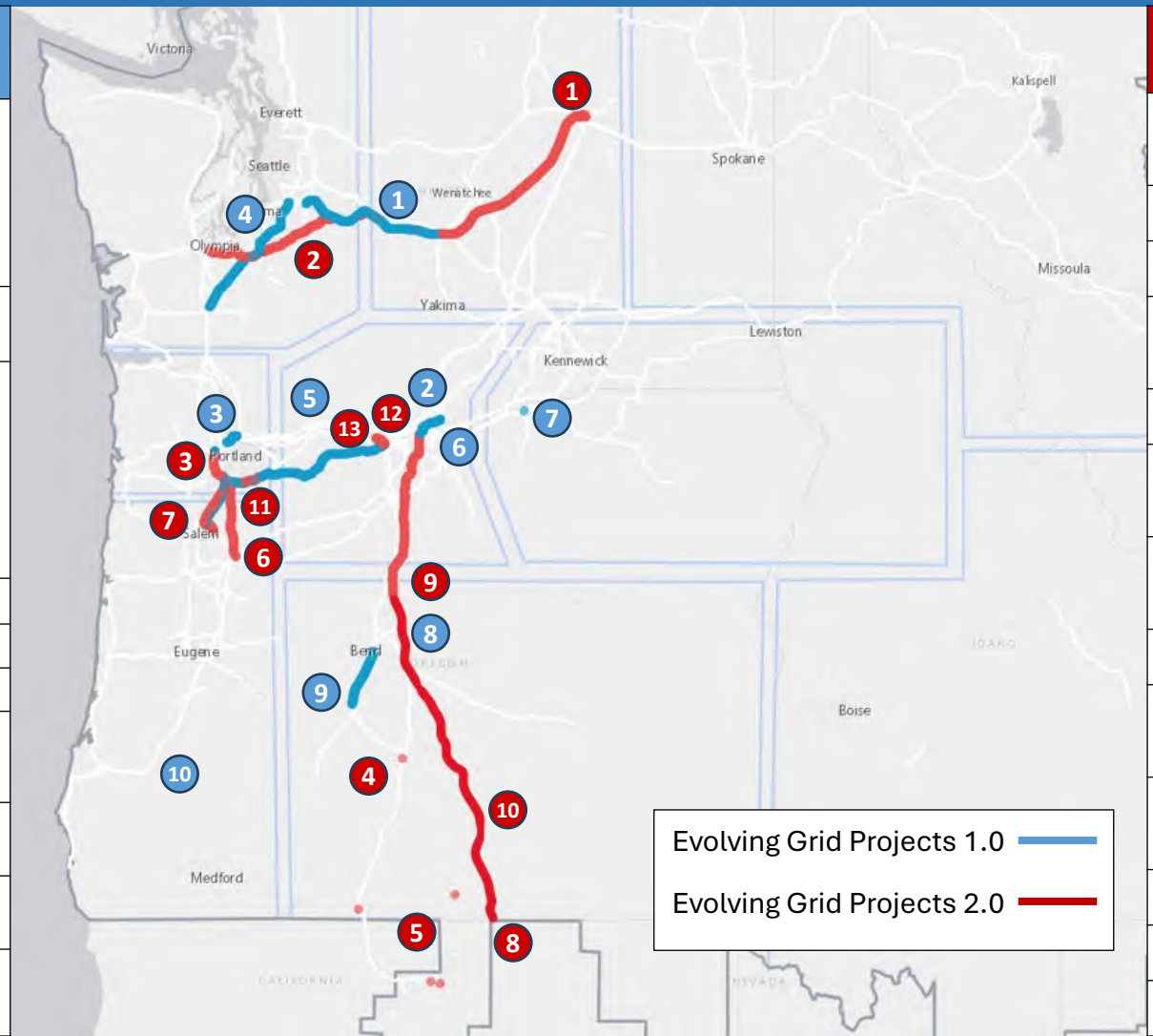

Evolving Grid 2.0

1	Grand Coulee-Columbia-Schultz 500 kV Line Upgrade
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10	Bonanza to NOB 500 kV Line (New Construction)
11	Ostrander-Pearl 500 kV Line Upgrade
12	Big Eddy-Quenett Creek Upgrade
13	Big Eddy-The Dalles Line Rebuild

EGP 1.0 & 2.0 Portfolio Q&A

- Panel discussion with BPA SMEs to review questions and clarifications from the October 17 public meeting.
- BPA has published an updated document with answers to questions and clarifications here:
  - Evolving Grid Project 1.0 & 2.0 Questions and Answers (updated 12/2/24)

Customer Reliability Improvement & Service Program (CRISP)

The Background

- BPA Transmission measures transmission line reliability in two forms:
  1. System Average Interruption Duration Index (SAIDI) measures the average minutes of unplanned interruptions per line per year.
  2. System Average Interruption Frequency Index (SAIFI) measures the average number of unplanned interruptions per line per year.
- SAIDI/SAIFI metrics are BPA transmission line-based, reported as part of the agency and transmission performance scorecards.
- Metrics provide an excellent system-wide overview of average performance. However, often some customers experience a much different Quality of Service (QOS) at their specific points of delivery (POD).
- BPA can analyze outages at each POD, which offers a more granular look at history from the customer perspective.

The Issue

- BPA's strategic plan outlines a vision to provide a reliable, resilient electric grid to support customers.
- Certain parts of BPA's transmission system historically provide a lesser quality of service (QOS) than others.
- Existing Network Integration Transmission Service (NITS) customers are routinely sending BPA letters of concern about their transmission service reliability.
- This briefing outlines an initiative to develop a program focused on improving customer reliability and reducing future risk exposure.

Current Reactive Approach

- No overarching program for projects geared towards customer QOS improvements.
- Discretionary (non-OATT).
- Not associated with new revenue, so the Net Economic Benefits Ratio (NEBR) is generally low or negative.
- Not compliance related and associated with adhering to NERC/WECC reliability standards.
- Submitted ad-hoc for approval yet are lower priority and compete for limited resources with projects deemed higher priority.
- No special funding allocation or budget.

Future Proactive Approach

- Develop programmatic approach and portfolio of Network Upgrades focused on:
  - Improving QOS.
  - Managing risk.
  - Providing equity for customers, including those served radially.
- Prioritize projects by leveraging potential future risk exposure information, historical outage data, and other factors.
  - Leading and lagging indicators.
- Acknowledge this is the right thing to do for BPA Transmission customers.
  - Specifically in areas that have historical weather extremes and wildfire danger where customers incur more risk than others.
  - Without this program, projects will not rise to the level of attention needed.
  - Good utility practice that will help strengthen customer relationships.

Example Projects

Funded Projects

- Chenoweth-Goldendale 115kV line
- L0479 Bridge Substation
- Disconnect Switch Replacement at Gold Beach
- USACE Dexter & Foster Powerhouse - Replace Ground Switch
- Eugene Alderwood 115kV Line Rebuild
- L0495 Latham Sub Reliability Project
- Targhee Substation Breaker and Expansion
- Alvey-Dillard Tap 115kV Line Rebuild

Identified Areas of Concern and Projects Need Further Evaluation

- Port Angeles-Sappho 115kV line
- Columbia Falls-Trego 115kV line
- Targhee tap to Swan Valley-Teton 115kV line
- Bald Mountain to Powerdale Tie
- Redmond-Brasada and Brasada-Harney 115kV lines

FY25 Plan

- Q1
  - Mature the program, develop expanded project inventory, brief executives, and provide initial customer outreach.
- Q2
  - Apply project valuation tools to draft prioritization and multi-year project forecast and develop future customer outreach plan.
- Q3
  - Finalize prioritization and multi-year project forecast and add specific Network Upgrade projects to the Asset Plan.
- Q4
  - Initiate highest prioritized projects to the Capital process and request project funding approval to begin scoping in FY26.

Summary

- Historically, less formalized.
- In the future, formalize, add structure, and pivot to new approach.
- Network Upgrades focused on improving QOS, managing risk, and providing equity for customers.
- Evaluate projects based on several criteria, including estimated cost, historical POD-specific outage metrics, public health and safety concerns, and potential future risk.
- Committed to FY25 performance scorecard metrics.
- Success of program will be dependent on project execution bandwidth.
- Continue to provide customers an opportunity to provide feedback, including via CSEs and AEs.

Customer LGIA Option to Build

Background on the LGIA Option to Build

- Bonneville adopted pro-forma changes to the Option to Build language in the TC-20 settlement
- This is an option under the Standard Large Generator Interconnection Agreement (LGIA)
  - Cannot be exercised until negotiating the LGIA
  - Bonneville does not tender LGIA until after environmental compliance is complete, which requires a percentage/completion of design

Background on Option to Build

LGIA Section 5.1.3: Interconnection Customer shall have the option to assume responsibility for the design, procurement and construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades on the dates specified in Article 5.1.2. Transmission Provider and Interconnection Customer must agree as to what constitutes Stand Alone Network Upgrades and identify such Stand Alone Network Upgrades in Appendix A. Except for Stand Alone Network Upgrades, Interconnection Customer shall have no right to construct Network Upgrades under this option.

Stand Alone Network Upgrades shall mean Network Upgrades that are not part of an Affected System that an Interconnection Customer may construct without affecting day-to-day operations of the Transmission System during their construction. Both the Transmission Provider and the Interconnection Customer must agree as to what constitutes Stand Alone Network Upgrades and identify them in Appendix A to the Standard Large Generator Interconnection Agreement. If the Transmission Provider and the Interconnection Customer disagree about whether a particular Network Upgrade is a Stand Alone Network Upgrade, the Transmission Provider must provide the Interconnection Customer a written technical explanation outlining why the Transmission Provider does not consider the Network Upgrade to be a Stand Alone Network Upgrade within 15 days of its determination.

Current Approach

- Currently, we work with interested customers when they reach the LGIA stage on a case-by-case basis to explore how the option would work for specific projects.
- Customers have expressed a desire to better understand how Option to Build works prior to reaching the LGIA stage.

Status Update

- We are continuing efforts to evaluate developing a standardized approach and providing public-facing materials to educate customers.
  - Conducted benchmarking with WAPA.
  - Identified required changes to standardize: Business Practice, Contracting Strategy, Contract Oversight Mechanism.
- Challenges to developing guidance and standardizing approach:
  - New or altered contracting mechanisms.
  - Ensuring consistency with statutory and legal obligations and that equipment or facilities built under the option meet BPA's reliability obligations.
    - For example, all design and construction must be to BPA standards.
  - Resource constraints due to prioritizing implementation of the large generator interconnection transition process (TC-25 reforms).

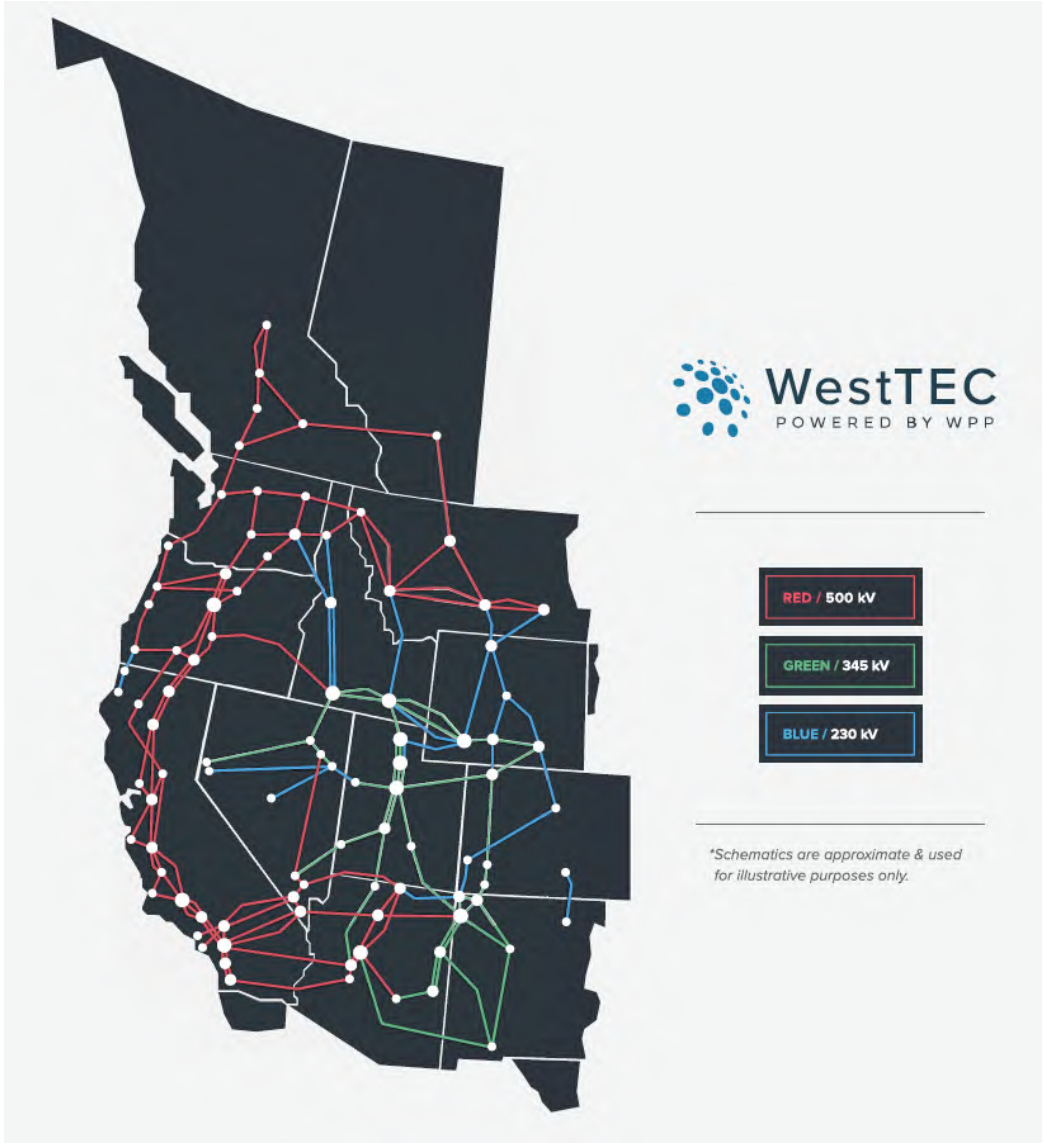
Update on WestTEC
BPA Evolving Grid Public Workshop

Crystal Ball, Pacific Northwest Utilities Conference Committee

Ravi Aggarwal, BPA Transmission Planning

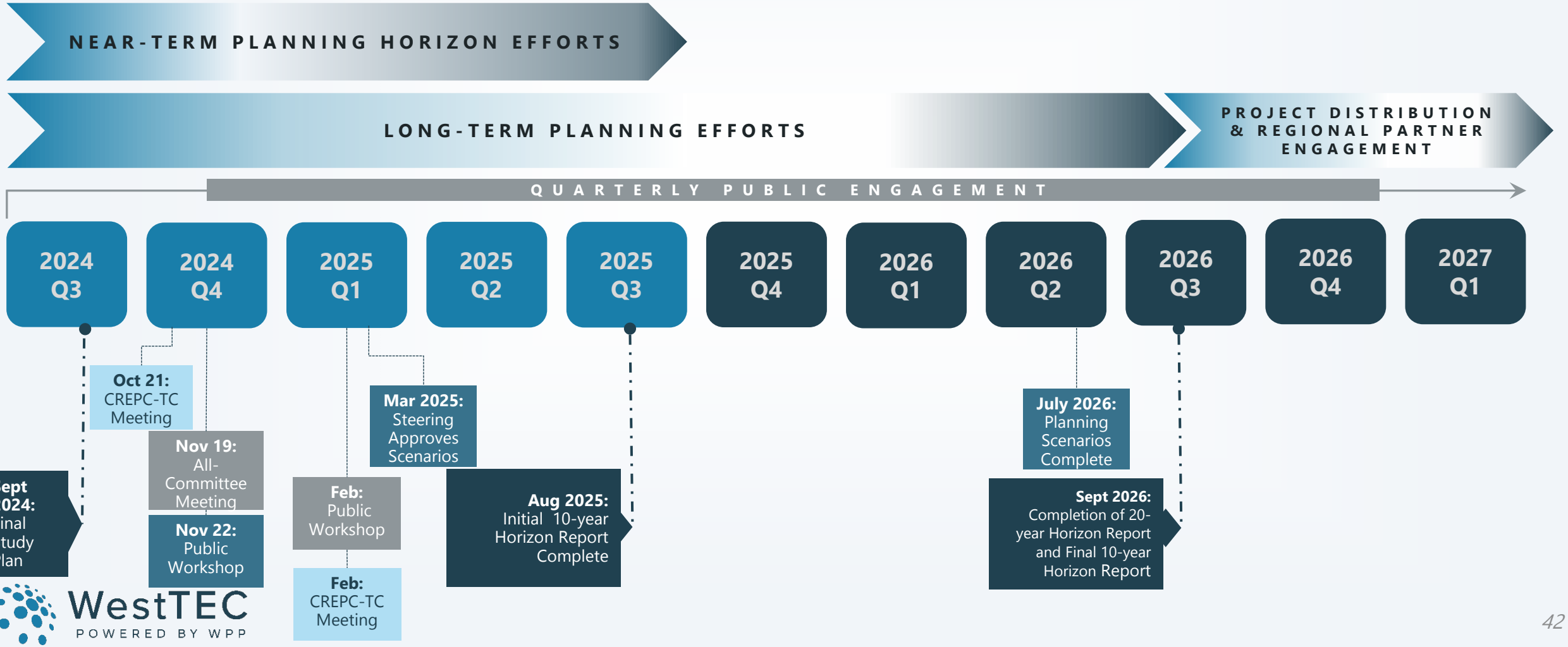
What is the Western Transmission Expansion Coalition?

- *"WestTEC"*
- *West-wide 20-year transmission study (10-year look)*
- *Industry-led with unprecedented stakeholder inclusion*
- *Goal is to produce an actionable transmission study*



WestTEC
POWERED BY WPP

WestTEC Project Timeline



WestTEC
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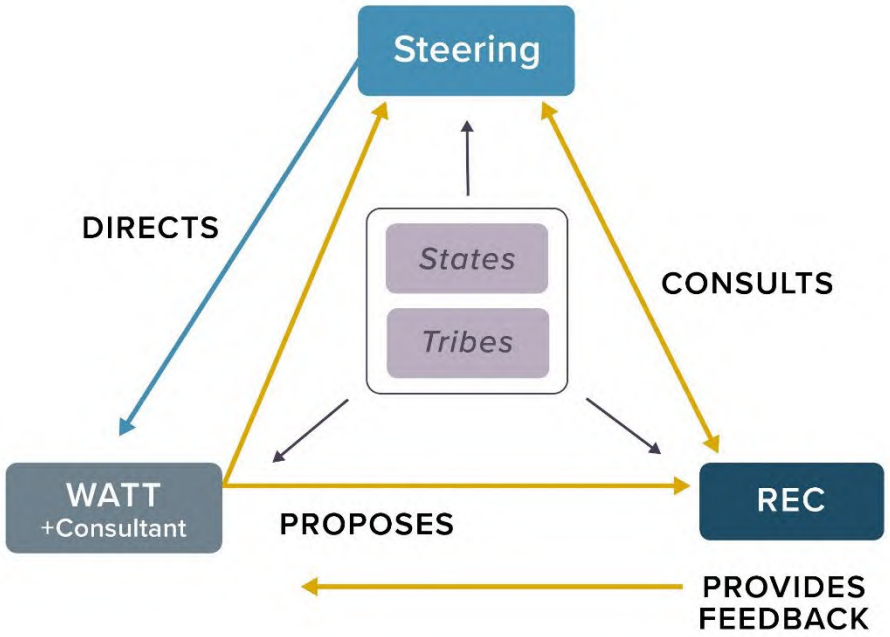
Committees and Governance



Technical Status Update

1. Significant progress has been made developing the **10-year Reference Case,** which is a trendline view of 2035 that will be used to assess nearer-term interregional transmission needs and will service as the starting point for 20-year assessments
   - » This consists of forecasts for **load, generation, and transmission** for the 2035 study horizon – see subsequent slides
2. Energy Strategies and the WATT have been **finalizing study methodologies** for the System Reliability Assessment
   - » The team will begin work refining other methods (e.g., Interarea Deliverability Assessment) soon
3. Energy Strategies and E3 have been coordinating baseline assumptions and data handoffs to support execution of 20-year assessment in 2025
   - » See next section for details on E3 capacity expansion modeling

Notable Transmission Projects included in 10-year Reference Case

- The following list is a list of notable projects that are regional in nature or are >300-kV, with some exceptions for certain 230-kV projects
  - The list does not include all projects that will be included in the WestTEC 2035 Reference Case, but captures major topology changes

BPA
- Montana to Washington (M2W)
- Cross Cascades North Upgrade TSEP 2022 (1)
- Raver -Paul: Chehalis - Cowlitz Tap 230 (4)
- Big Eddy - Chemawa rebuild (2)
- North of Marion: Marion-Chemawa-Pearl 500 (6) (7)
- North of Pearl 500-kV upgrade (incl. Pearl-Keeler #2 500) (3)
- Schulta - Olympia 500 kV Transmission Line (2)
- Grand Coulee - Columbia - Schultz 500-kV (1)
- Big Eddy - Ostrander #1 500 (2)
- Ostrander - Pearl #1 500 (11)
- South of Knight: Rock Creek-John Day 500 kV line upgrade (6)
- South of Allston: Ross-Rivergate 230 (5)
- Bonanza - Lapine 230 kV (9)

CAISO
- All CAISO approved projects as of 23-24 TPP
- TransWest Express
- SWIP North
- SunZia
- Imperial Valley–North of SONGS 500 kV Line and Substation
- Colorado River-Red Bluff 500 kV 1 Line Upgrade
- Delaney-Colorado River 500kV line
- North of SONGS–Serrano 500 kV line
- Serrano–Del Amo–Mesa 500 kV Transmission Reinforcement
- San Jose Area HVDC 230 kV Line (Newark - NRS)

PacifiCorp
- Gateway West: Borah to Midpoint (E-North)
- Gateway West: Bridger/Anticline to Populus (Segment D3)
- Gateway West: Cedar Hill to Hemingway (E-south)
- Gateway West: Cedar Hill to Midpoint (Segment E)
- Gateway West: Midpoint to Hemingway (Segment E8)
- Gateway West: Populus to Borah (E-North)
- Gateway West: Populus to Cedar Hill (E-south)
- Corral to Grassland Annex 500kV Line
- Corral to Snow Goose 500kV Line
- Energize the existing Red Butte – St. George line at 345 kV
- Gateway Central: Limber to Terminal (Segment C)
- Grassland Annex to B2H Tap Substation 500kV Line
- Oquirrh-Terminal 345 kV #3 and #4 Double Circuit Line
- Sigurd - Clover 345 kV line
- Spanish Fork - Mercer 345 kV line
- Three Peaks - Purgatory Flat 345 kV line

IPCo/PacifiCorp
- Longhorn to Hemingway (B2H)

Arizona Public Service
- Four Corners to Cholla to Pinnacle Peak 345kV Line Rebuilds
- Jojoba to Rudd 500kV line

Cheyenne Light Fuel and Power
- Sweetgrass - Bluffs 230 kV Line
- West Cheyenne - Sweetgrass 230 kV Line
- West Cheyenne - Windstar 230 kV Line

Idaho Power
- Hemingway - Bowmont #2 230 kV line
- Hubbard - Bowmont 230 kV line

Salt River Project
- Hassayampa - Pinal West 500kV #2

Public Service Company of Colorado/ Xcel Energy
- Colorado's Power Pathway

Tucson Electric Power
- DMP to Vail 230kV line
- Golden Valley 230kV Transmission Line
- Tortolita to DMP 230kV line

NV Energy
- Greenlink North
- Greenlink West
- Lantern – Comstock Meadows 345 kV line

El Paso Electric Company
- Afton North-Airport 345 kV Line (New)
- Afton-Afton North 345 kV Double Bundled Line (New)

Portland General Electric
- Bethel-Round Butte 500kV upgrade
- Harborton-Trojan #3 & #4 230kV

Tri-State Generation and Transmission Association
- Badger Creek - Big Sandy 230 kV
- Big Sandy - Burlington 230 kV Uprate
- Boone - Huckleberry 230 kV
- Burlington - Lamar 230 kV

Western Area Power Administration (all regions)
- Bouse upgrade
- Pinal Central - ED5 Transmission Line
- Pinnacle Peak - Rogers 230kV Restoration Project
- Ault-Husky 230KV Line Upgrade

Key
- Regional projects

WestTEC POWERED BY WPP

Not final and subject to change

BONNEVILLE POWER ADMINISTRATION

Evolving Grid Projects 1.0 & 2.0

Evolving Grid 1.0

1	Cross Cascades North Upgrades • Schultz-Raver 500 kV Line Upgrade • Paul 500 kV Substation Upgrade • Olympia 230 kV Substation Upgrade
2	Big Eddy-Chemawa 230/500 kV Line Upgrade
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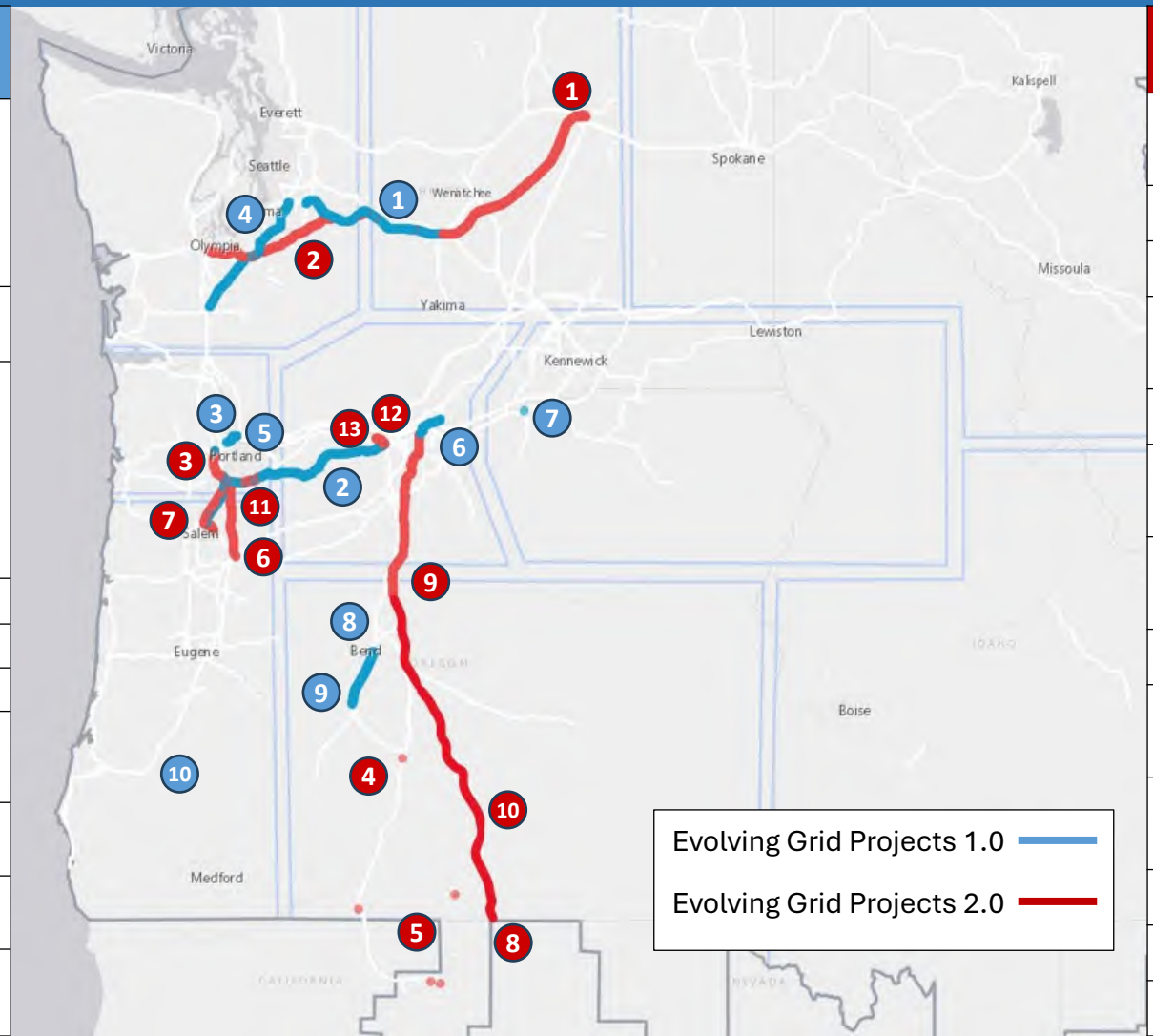

Evolving Grid 2.0

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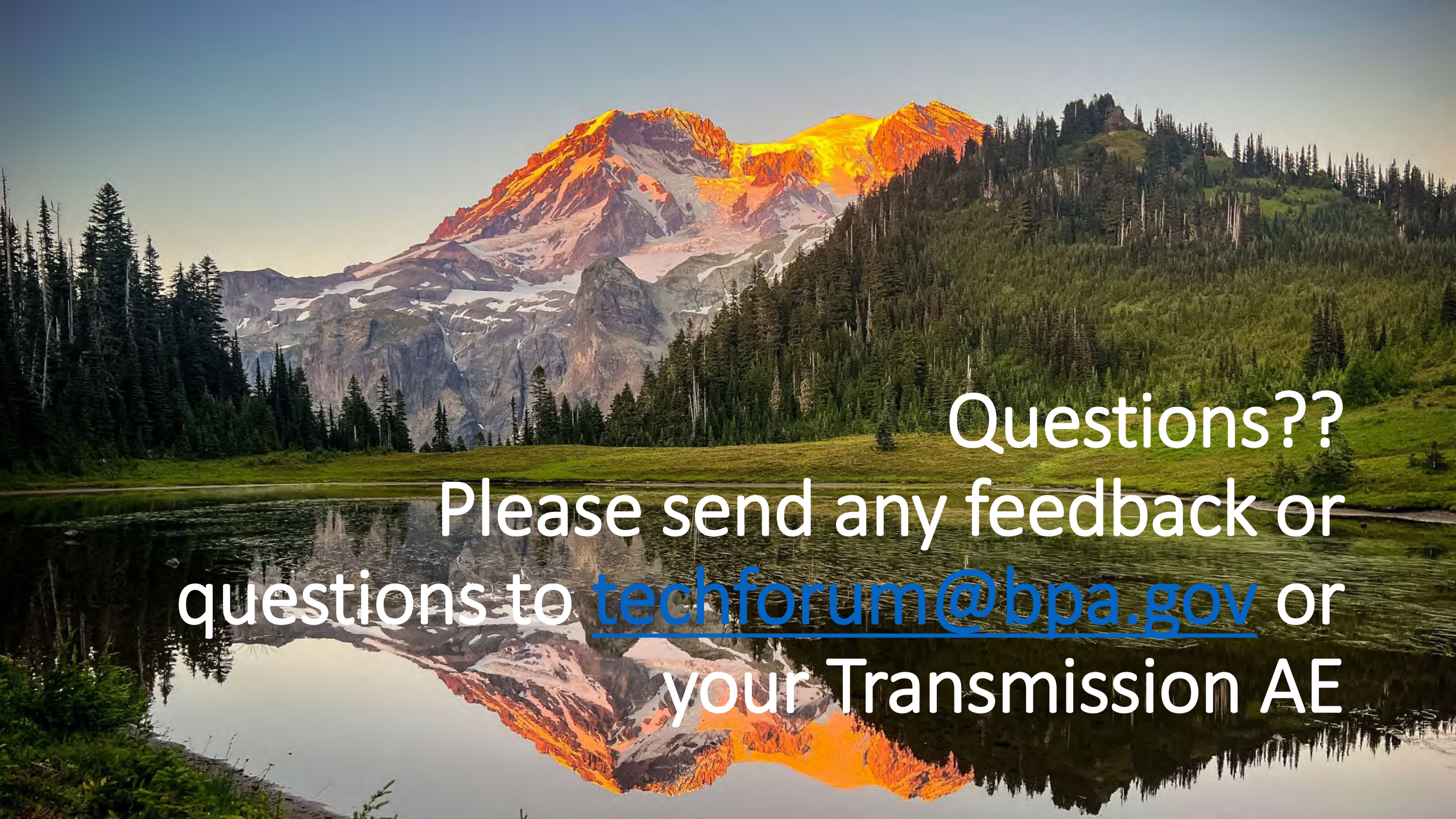
Questions??
Please send any feedback or
questions to techforum@bpa.gov or
your Transmission AE

Appendix: Helpful BPA Links

New Evolving Grid web page: https://www.bpa.gov/energy-and-services/transmission/evolving-grid

BPA Transmission Plan: https://www.bpa.gov/energy-and-services/transmission/attachment-k

Transmission Availability : https://www.bpa.gov/energy-and-services/transmission/transmission-availability

Becoming a BPA Customer: https://www.bpa.gov/energy-and-services/transmission/becoming-a-transmission-services-customer

Interconnection: https://www.bpa.gov/energy-and-services/transmission/interconnection

Transmission Service Request Study: https://www.bpa.gov/energy-and-services/transmission/acquiring-transmission/tsep

Transmission Business Model: https://www.bpa.gov/energy-and-services/transmission/business-model

Attachment 2. PGE Clean Energy Plan and Integrated Resource Plan (CEP-IRP) 2023

November 2025

Clean Energy Plan and Integrated Resource Plan 2023

PGE

This document contains forward-looking statements, including those regarding implementation of our business plans, technology transitions, our business, strategies and financial performance, our offerings of new services, and other statements that are not historical fact, and actual results could differ materially from these forward-looking statements. Risk factors that could cause actual results to differ are set forth in the "Risk Factors" section, as well as other sections of our 2022 Annual Report on Form 10-K, available on our website at investors.portlandgeneral.com/financial information/sec-filings, as well as, or in addition to, other filings with the SEC. All forward-looking statements are based on management's estimates, projections, and assumptions as of the date of filing, and we undertake no obligation to update any such statements.

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This document is based on the best available information at the time it was prepared but is subject to change without notice.

Portland General Electric Company
Integrated Resource Planning
121 SW Salmon Street
Portland, Oregon 97204

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CEO Message

At Portland General Electric (PGE), we take pride in providing safe, reliable, affordable and increasingly clean power to homes, businesses and communities. Delivering this essential service is a responsibility that we have embraced for more than 130 years, and today, one that reflects evolving values and expectations.

For decades, customers have made clean energy a top priority. Echoing that sentiment, today many customers have aggressive climate goals and communities we serve have comprehensive climate action plans. In 2021, the Oregon Legislature passed landmark public policy that affirmed and mandated PGE's goals for decarbonization. This inaugural Clean Energy Plan, filed in conjunction with our 2023 Integrated Resource Plan, is a comprehensive roadmap detailing how we will meet customers' energy needs and greenhouse gas emissions targets while maintaining reliability, safety and affordability.

These targets are also in line both with the science-driven United Nations 6th IPCC Report, and with the policy of the federal government, which is providing significant financial resources to states, communities, utilities and customers through the Inflation Reduction Act and the Infrastructure Investment and Jobs Act.

Meeting our targets and decarbonizing our system will require significant investment in diverse resources, as well as investments in new transmission infrastructure, technology and innovation, as well as wider regional collaboration. We will invest in a full range of clean energy resources and tools, including large-scale wind and solar projects, battery storage, energy efficiency, demand response, customer-sited resources and community based renewable energy.

This is a significant undertaking, requiring us to try new things as well as adopt and evolve when new technologies, opportunities and challenges present themselves.

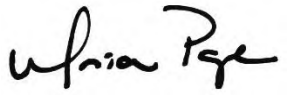
Importantly, we cannot implement this Clean Energy Plan and Integrated Resource Plan alone. Success depends on the commitment of customers as well as leaders and partners throughout the community. This plan calls for community-based renewable energy and customer participation in energy efficiency and demand response programs. We rely on key partners, ranging from community colleges and labor unions who enable well-trained workers, to suppliers and contractors of various types and sizes who provide reliable sources of materials and equipment.

In the pages that follow, we outline how we will meet future energy and capacity needs while achieving emissions targets, reliably and affordably. Central to this plan is PGE's commitment

to diversity, equity and inclusion. We must decarbonize in ways that benefit everyone, with an attentive eye to historically underserved communities.

Thank you for your interest, partnership and willingness to think differently as we work together in building a clean energy future.

Maria Pope



President and CEO, PGE

Introduction

Portland General Electric (PGE, or the Company) is proud to submit our combined, 2023 Clean Energy Plan and Integrated Resource Plan (CEP/IRP) for consideration by our customers, stakeholders, communities and the Public Utility Commission of Oregon (OPUC, or the Commission).

PGE's purpose is to power the advancement of society. We have served our customers with safe, reliable and affordable power for over 130 years. We engage in robust planning, analysis, stakeholder and community engagement to inform our investments in resources, customer programs and the grid. We are committed to balancing affordability, reliability and reductions in greenhouse gas (GHG) emissions across all of our planning efforts.

As Oregon's largest electricity supplier, we recognize our unique role in addressing climate change and leading an equitable clean energy transition in Oregon. We reflect this commitment in our climate-related goals and detailed disclosures of our progress in our annual environmental, social and governance (ESG) report. We also see it aligned with the climate and clean energy goals of many of the customers and communities we serve. This CEP/IRP represents a continuation of our clean energy journey, which began years ago in response to customer demands, climate science, emerging technologies and market opportunities.

Oregon's landmark clean energy legislation, HB 2021, and unprecedented federal government support for clean energy, is now transforming how PGE provides excellent service to customers. The 2023 IRP is PGE's first long-term resource plan since the passage of HB 2021, which established PGE's climate goals into law with firm targets for reducing emissions associated with Oregon retail sales. HB 2021 requires PGE to file a CEP, detailing our plans to achieve annual progress toward achieving emissions targets with consideration for the benefits for local communities.

These emissions targets and the expectations outlined in the pursuant Commission orders inherently change PGE's approach to long-term resource planning. Emissions targets are now an integral component of PGE's IRP modeling. At the same time, PGE cannot demonstrate a balanced, feasible path toward emissions targets without also estimating future energy and capacity needs and identifying an optimal portfolio of resources to meet those needs, subject to emissions constraints. Our CEP and IRP are tightly integrated and as such, PGE is submitting the CEP and IRP as a single planning document, responsive to the OPUC's requirements, guidelines and expectations for both planning documents. The CEP serves as our accessible roadmap to the clean energy transition. The IRP functions as the detailed analytical foundation. Both share common methodologies and recommendations.

Our CEP/IRP details a pathway to meeting future energy and capacity needs and emissions targets, given what we know today, and acknowledges the significant change and uncertainty confronting our industry in the coming decades. We propose measured, near-term actions to serve our customers with reliable, affordable and increasingly clean power consistent with achieving our 2030, 2035 and 2040 emissions targets. Those near-term actions represent specific steps PGE intends to take with acknowledgement by the OPUC.

This filing is the result of continued and iterative planning and analysis, during which, we have emphasized and evolved our venues for stakeholder and community input. As has been underscored throughout this process, diverse stakeholders will view the document through their own lens. To aid in reviewing this first CEP/IRP submission, we highlight the following navigational tips:

- Chapter 1 details the company's strategies, planned actions and forecasted emissions in response to HB 2021 requirements. Chapter 1, combined with Chapters 7, 13 and 14 address the bulk of CEP guidelines and expectations outlined in HB 2021 and the Commission's orders;
- Chapters 2-6 and Chapters 8-12 serve as the more traditional components of the IRP. As noted above, HB 2021 and Commission orders necessitated changes in IRP methodology and analysis. As a result, there are CEP expectations addressed in some of the IRP chapters. For example, community-based renewable energy (CBRE) resources are included in the IRP's set of Resource Options;
- Chapters 11 and 12 provide a single Preferred Portfolio and Action Plan that reflect the near-term actions we intend to pursue to satisfy energy and capacity needs and emissions reduction requirements; and
- Appendix B provides a crosswalk for the reader to identify where each particular IRP guideline or CEP expectation from HB 2021 or Commission orders are met.

Our goal throughout the planning process was to produce a CEP/IRP that provides clarity on our priorities and values, responds to feedback, and aligns with the public policy goals of Oregon. We set out to mitigate risks for customers while balancing affordability and emissions reduction during a highly dynamic period of change for our industry. We sought to create a plan that was flexible and could be adapted as we continue to learn and as conditions change and new technologies and market opportunities arise.

Importantly, we wanted a plan that would invite further conversations with our customers, communities, stakeholders and the Commission. We would like to acknowledge the time, work, valued inputs and contributions of so many participants to this process over the course of many workshops and other venues. Moving forward, it will take all of us working together to implement the actions identified in this filing and successfully navigate an equitable clean

energy transition for Oregon. We share the incredible sense of urgency and look forward to working together to implement next steps.

Summary of key findings from the 2023 CEP/IRP

- PGE has already reduced emissions from power sold to Oregon retail customers by 25 percent below 2010-2012 baseline emissions.
- Electrification of vehicles, homes and businesses will accelerate load growth in the years ahead. This CEP/IRP anticipates and plans for that load as PGE decarbonizes.
- PGE will need to add non-emitting energy resources and capacity at an accelerated pace in order to maintain system reliability while it systematically reduces fossil fuel purchases and generation to achieve emissions targets.
- PGE's planned path to emissions targets features a linear decline in emissions associated with sales to Oregon retail customers from 2026-2030 and 2030-2040. Actual reductions may vary year-by-year due to variables that impact emissions that are beyond PGE's control and/or the pace of clean energy acquisition and integration.
- Achieving emissions targets reliably and affordably will require access to a wider geographic diversity of resources and the transmission solutions to access them. Participation in regional markets and partnerships that allow PGE to pool resources and source clean energy from across the West can increase reliability and lower costs for our customers.
- Significant transmission constraints drive a greater role for customer-sited resources, including demand response and energy efficiency, and community-based renewable energy resources in this CEP/IRP. PGE plans to pursue all cost-effective energy efficiency and demand response during the Action Plan window. PGE establishes a target for CBRE resources of 155 MW by 2030 with plans to pursue at least 66 MW by 2026.
- The growing role of customer-sited and community-based renewable energy resources in PGE's decarbonization efforts underscores the importance of PGE's ongoing efforts to enhance the capacities of distributed energy resources to provide local and system value when managed as a Virtual Power Plant.

- PGE forecasts a significant capacity need of 1136 MW in summer, 1004 MW in winter, and a significant energy need of 905 MWa (~2,500 MW nameplate) by 2030.
- Policy and market changes could change PGE's estimated future energy and capacity needs but the near-term actions proposed during the Action Plan window are the same: conduct one or more Request for Proposals (RFPs) for an additional 181 MWa (~520 MW nameplate) of non-emitting generation and sufficient capacity to remain resource adequate each year.
- 2030 emissions targets can be met with technologies and resources that are currently known and commercially available.
- Pathways to 2040 emissions targets will require further development of non-emitting resources and transmission to meet the region's energy and capacity needs.
- PGE's natural gas plants will continue to play a role in helping to meet our resource adequacy needs during the clean energy transition. PGE will continue to invest in the efficiency, safety and emissions controls of those facilities as appropriate.
- Efforts to specify the sources of generation for resources currently procured through short-term market purchases will reduce PGE's reported emissions and future energy needs.
- Utilizing federal, state and local funding opportunities to support decarbonization on our system will mitigate customer price pressure during the transition.
- PGE's success will require deep and continued collaboration with our customers, communities and stakeholders and with a wide range of leaders at all levels of government.

Chapter 1. Clean energy plan

House Bill (HB) 2021 is a transformative public policy setting Portland General Electric (PGE) on a path to decarbonizing the power supply for Oregon retail customers.[1] To inform our approach to meeting the greenhouse gas (GHG) emissions targets specified by HB 2021, we have engaged in robust planning, analysis, stakeholder and community engagement. Throughout our planning, we remain committed to balancing affordability for customers, the reliability of the grid and GHG reductions.

We begin this chapter by describing our vision for a clean energy future and our role in leading an equitable clean energy transition across our service territory. Before discussing our decarbonization strategies, we provide an overview of our system emissions and historic progress. Notably, in this chapter, we summarize the results of Integrated Resource Plan (IRP) modeling and portfolio analysis developed over subsequent chapters, which form the basis of our Clean Energy Plan (CEP) and detail our path to compliance with HB 2021 emissions targets.

Chapter highlights

- To meet our emissions targets, we have identified a significant need to procure non-emitting resources and capacity to keep pace with new customer demands.
- Achieving emissions targets reliably and affordably requires systematically replacing fossil fuel generation and purchases with non-emitting energy and capacity resources.
- Transmission is a significant factor impacting the economics and timing of resource additions to meet HB 2021 targets. Transmission solutions are integral to meeting our targets.
- Significant transmission constraints will drive a greater role for customer-sited resources such as demand response (DR), energy efficiency (EE), distributed solar/storage and community-based renewable energy (CBRE) resources, highlighting the importance of PGE's efforts to improve our utilization of these resources through a virtual power plant (VPP).

[1] House Bill (HB) 2021 codified as ORS 469A.400 to 469A.475, effective 09/25/2021.

- 2030 emissions targets can be met by technologies and resources that are currently known and commercially available.
- Decarbonization pathways to 2040 will require further technological advancement of non-emitting resources and transmission to meet the region's energy and capacity needs.

At PGE, we are privileged to serve Oregon communities with an essential service foundational to the well-being and vitality of society. Our responsibilities are significant, and we are continuously evolving our ambitions and best practices to advance social equity and environmental sustainability in the communities we serve. We are firmly committed to a future in which all Oregonians can thrive.

We have supported Oregon communities with reliable, affordable and safe power for over 130 years. While many things have changed over that time, our core responsibility to power Oregon homes and businesses has not. It has become increasingly apparent that climate change poses significant risks to the power sector across all regions of the country. Extreme weather and natural disasters threaten utility infrastructure, contribute to energy market volatility and render the balancing of energy supply and demand more challenging. At PGE, we have witnessed the impacts of climate change first-hand in the form of record-breaking winter and summer energy peaks, damaging and disruptive storms, and wildfire risk.

Importantly, climate change threatens the health and well-being of the communities we serve, and our most vulnerable communities, including Black, Indigenous and People of Color (BIPOC) and communities experiencing economic hardship, are often the most negatively impacted. As the state's largest electricity provider, we have a unique responsibility to address the challenges of climate change head-on and lead the transition to cleaner, non-emitting sources of energy. Integral to this work is our commitment to diversity, equity and inclusion and to supporting everyone's opportunity to participate in and benefit from a clean and reliable energy future.

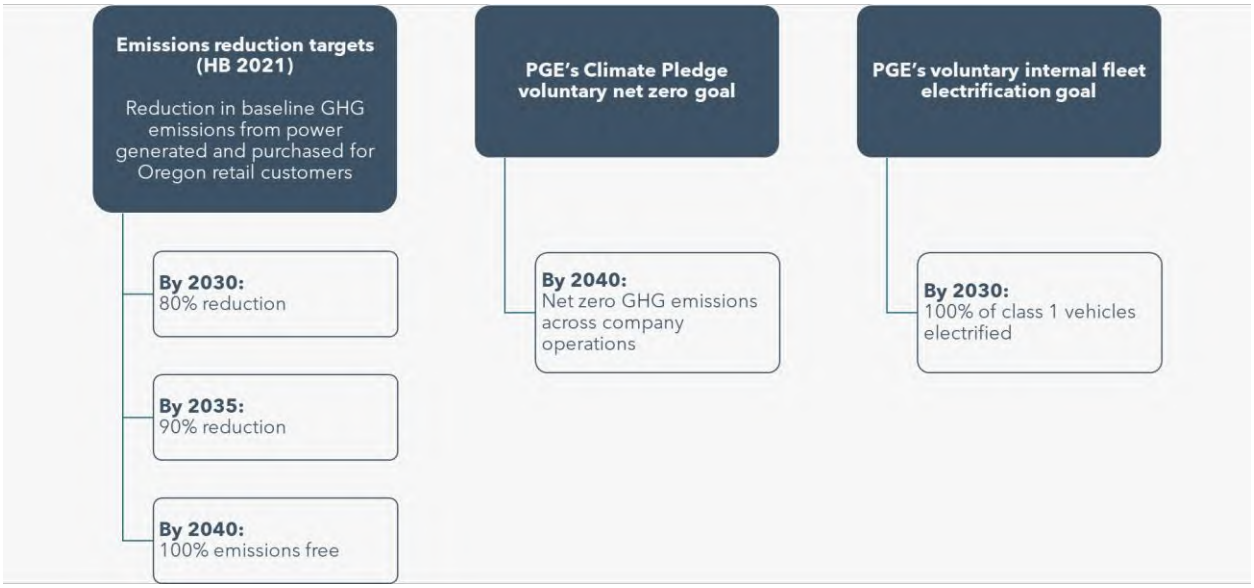
Our commitment to equity is important across all areas of our business, but especially as we acknowledge the disproportionate impacts of climate change on vulnerable communities. We seek to decarbonize our system in ways that can benefit traditionally underserved communities across our service territory. In **Chapter 7, Community benefits indicators and community-based renewable energy**, we describe our efforts to apply an equity lens to our resource and decarbonization planning. In **Chapter 14, Community equity lens** we describe our efforts throughout our planning process to create an inclusive process in which all the diverse communities we serve can participate and be heard.

We also seek to ground our resource and decarbonization planning efforts in the best available climate science, including the United Nations Intergovernmental Panel on Climate Change (IPCC) Sixth Assessment Report and the Oregon Climate Change Research Institute's Sixth Oregon Climate Assessment.[2,3] We see this reflected in climate-related goals that the company has set in recent years (described in **Figure 1**), as well as our detailed disclosures of environmental, social and governance (ESG) metrics and progress in our annual ESG report.[4] We view our responsibility to address climate change as broad, including decarbonizing the power we generate and purchase for customers; reducing emissions associated with other areas of our company's operations, such as our own vehicle fleets and buildings; and preparing our system for, and working with customers to support, their continued electrification of vehicles, homes, buildings and industrial systems.

PGE has been committed to reducing emissions for many years and in 2020 announced its voluntary goal to achieve company-wide net zero carbon emissions by 2040. PGE then became the first US utility to sign The Climate Pledge in 2021, joining what is now more than 385 companies worldwide in committing to net zero emissions by 2040, 10 years ahead of the Paris Accords.[5] Having established these emissions reduction goals, PGE then welcomed the opportunity to collaborate with community groups, policy makers and other stakeholders around the potential for state mandated targets for emissions for power generated and purchased for Oregon retail customers, in what eventually became House Bill 2021 (HB 2021).

[2] United Nations Intergovernmental Panel on Climate Change (IPCC) Sixth Assessment Report available at: https://www.ipcc.ch/assessment-report/ar6/
[3] Oregon Climate Change Research Institute's Sixth Oregon Climate Assessment available at: https://blogs.oregonstate.edu/occri/oregon-climate-assessments/
[4] PGE's ESG report is available at: https://portlandgeneral.com/about/who-we-are/sustainability
[5] Information about The Climate Pledge is available at: https://www.theclimatepledge.com/us/en

Figure 1. PGE's climate goals and targets



House Bill 2021 sets PGE on a course to providing Oregon retail customers with energy from generation and power purchases that is 100 percent GHG emissions-free by 2040, with important emissions milestones required along the way.[6] As described in **Chapter 14, Community equity lens**, **Chapter 13, Resilience**, and **Chapter 7, Community benefits indicators and community-based renewable energy**, HB 2021 also requires PGE to meaningfully include equity, resilience and CBRE resources as part of its decarbonization efforts, and to begin to evolve its resource planning approach to include a broader range of community benefits. The inclusion of community benefits marks a change in how utilities like PGE evaluate resources and other system investments to serve customers. We have taken some important initial steps in this combined filing of our CEP and IRP to identify community benefits indicators and adapt our IRP methods to begin including them. We look forward to future improvements as we continue our engagement with communities.

Filing this inaugural CEP with our 2023 IRP is an important first step in charting a course to achieving emissions targets in 2030, 2035 and 2040 that balances affordability and reliability for customers. Our utility has learned much in this process, and we will continue to learn more and adapt our strategies as the market, technologies and the needs of customers continuously evolve. As described in the following sections, the path to the 2030 emissions target is predicated on technologies and resources that are currently known and commercially feasible and available. But as we look beyond the initial 2030 target, there are still important unknowns regarding technology, resource economics and regulation.

[6] ORS 469A.405.

But this is what we do know. Our ability to serve load in the future will hinge on our ability to plan for and procure the best combination of resources that balances costs and risks for customers to meet our emissions targets safely and reliably. Decarbonizing our power supply will require resource acquisition and integration at a pace and scale unprecedented in our utility's history. It will require changes in how we procure resources for our system, how we operate our system, how we participate in energy markets, how we collaborate with other regional energy players, and ultimately, how we provide exceptional electricity service to customers. These changes will be informed by science, market research, rigorous modeling, data analytics, guidance from our regulators and policy makers, and importantly, from robust engagement with customers and communities.

Decarbonizing our system will require significant new investment in energy resources and distribution and transmission infrastructure to prepare for the smart, clean energy grid of the future. Our commitment to energy access and affordability is more important now than ever before. Customers already rely on us for their essential electricity needs. As we look to the future, customers will rely on us further as they electrify their vehicles, homes and businesses. Affordability drives us to continuously innovate, deploy new technologies, launch new programs, simplify processes and reduce costs while delivering exceptional customer experiences.

We will continue to actively manage costs for customers as we transition to an energy mix that meets our emissions targets. This includes careful and inclusive planning through our Clean Energy Plan, Integrated Resource Plan and Distribution System Plan processes, competitive procurement through our Requests for Proposals (RFPs) for resources, and our continuous efforts to improve operational efficiency, safety, system and equipment reliability. We are also actively pursuing federal and state grant funding opportunities to offset investment costs and support key decarbonization initiatives on behalf of customers, including infrastructure upgrades. We are also supporting efforts to connect customers with the unprecedented federal tax incentives and rebates available, ranging from electric vehicles to heat pumps to rooftop solar.

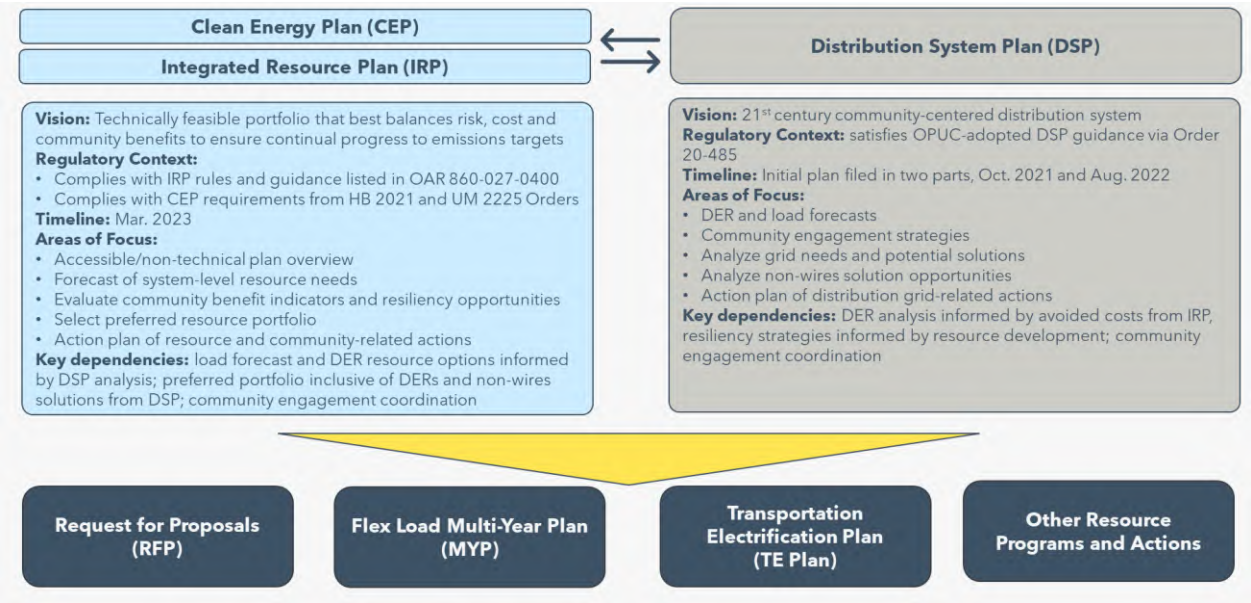
We remain committed to supporting customers with the tools to manage their own energy costs. This includes expanding systems that give customers insights into their energy use and supporting customers in paying their electricity bills through access to federal and state energy assistance programs, and PGE's Income Qualified Bill Discount (IQBD) Program. At the close of 2022, there were more than 47,000 households enrolled in PGE's IQBD program. We also recognize that managing costs also involves addressing societal barriers that make it harder for people to access energy savings, clean energy and energy assistance and collaborating with community groups to support state and federal legislation that helps low-income and vulnerable communities meet their energy needs.

1.1 Aligned planning

The combined filing of the CEP and IRP is the cornerstone of PGE's vision for a balanced, comprehensive, collaborative and streamlined planning process to achieve emission targets. It is situated within an evolving utility regulatory planning landscape where connectivity and alignment across planning strategies are increasingly complex and necessary, sharing our journey toward decarbonization clearly and concisely. As a result, it connects the dots for our regulators, policymakers, customers, stakeholders and communities between multiple planning requirements.

The combined plans are informed by data and outputs from other planning processes; references are provided throughout the plan accordingly. Notably, load and distributed energy resource (DER) adoption forecasts and hosting capacity analysis from the Distribution System Plan (DSP) inform IRP analysis of system needs and preferred resource options. The CEP and IRP Action Plan then provides the need and key inputs for successive planning activities presented through RFP materials, the Flexible Load Multi-Year Plan (MYP) and Transportation Electrification (TE) Plan, as depicted in **Figure 2**.

Figure 2. Coordination between planning activities [7] [8]



[7] OAR 860-027-0400, available at: https://secure.sos.state.or.us/oard/viewSingleRule.action?ruleVrsnRsn=221555.
[8] See *In the Matter of Public Utility Commission of Oregon, Consideration for Adoption Staff Proposed Guidelines for Distribution System Planning*, Docket No. UM 2005, Order 20-485 (Dec 23, 2020), available at: https://apps.puc.state.or.us/orders/2020ords/20-485.pdf.

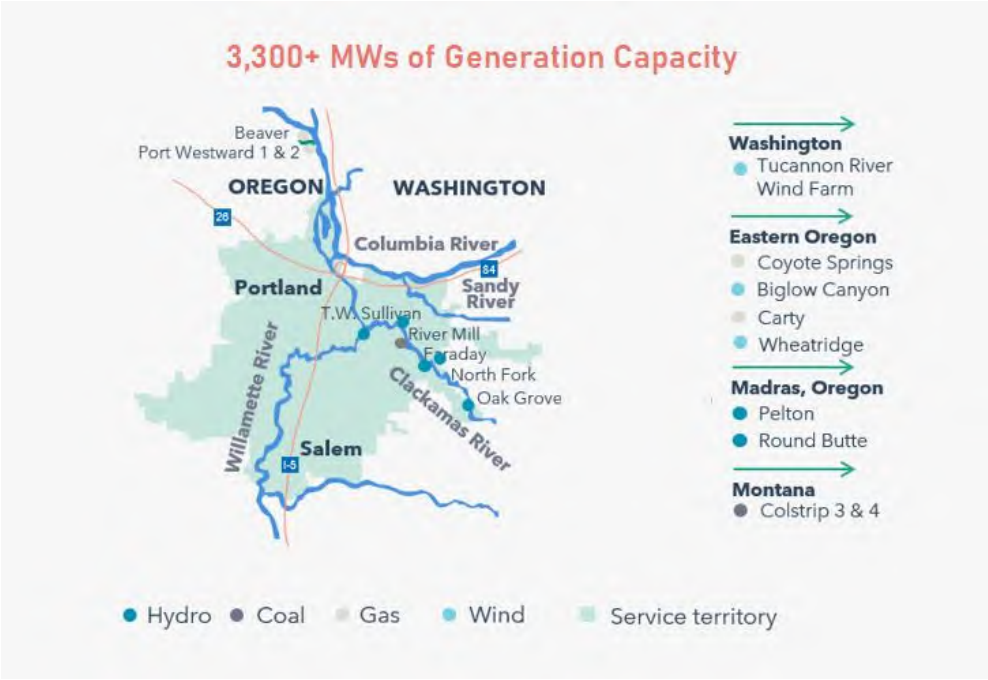
PGE also has sought to promote alignment of engagement processes, as discussed in **Chapter 14, Community equity lens**. Coordinated engagement strategies between the CEP, IRP, DSP and other venues seek to reduce workload wherever possible. Going forward, these engagement activities will also seek to align with new processes related to PGE's Community Benefits and Impacts Advisory Group (CBIAG). The result of these proceedings must meaningfully reflect stakeholder and community input.

This new landscape requires thoughtful and ongoing discussion. For example, there are still many outstanding questions on how CEP guidance will impact existing DSP guidelines and inform resource acquisition actions and proactive investments in the distribution system to accelerate decarbonization as envisioned in HB 2021. We look forward to working with the Public Utility Commission of Oregon (OPUC or the Commission), stakeholders and community members to further develop and refine the DSP guidelines.

1.2 Historical emissions trends and resource mix

PGE is a vertically integrated electric utility encompassing generation, transmission and distribution. PGE is Oregon's largest electricity provider, serving over 900,000 retail customers within a service area of 1.9 million residents. Roughly half of Oregon's population lives within PGE's service area, encompassing 51 incorporated cities entirely within the State of Oregon. Seventy-five percent of Oregon's commercial and industrial activity occurs in PGE service area.

Figure 3. PGE's service area and generation capacity



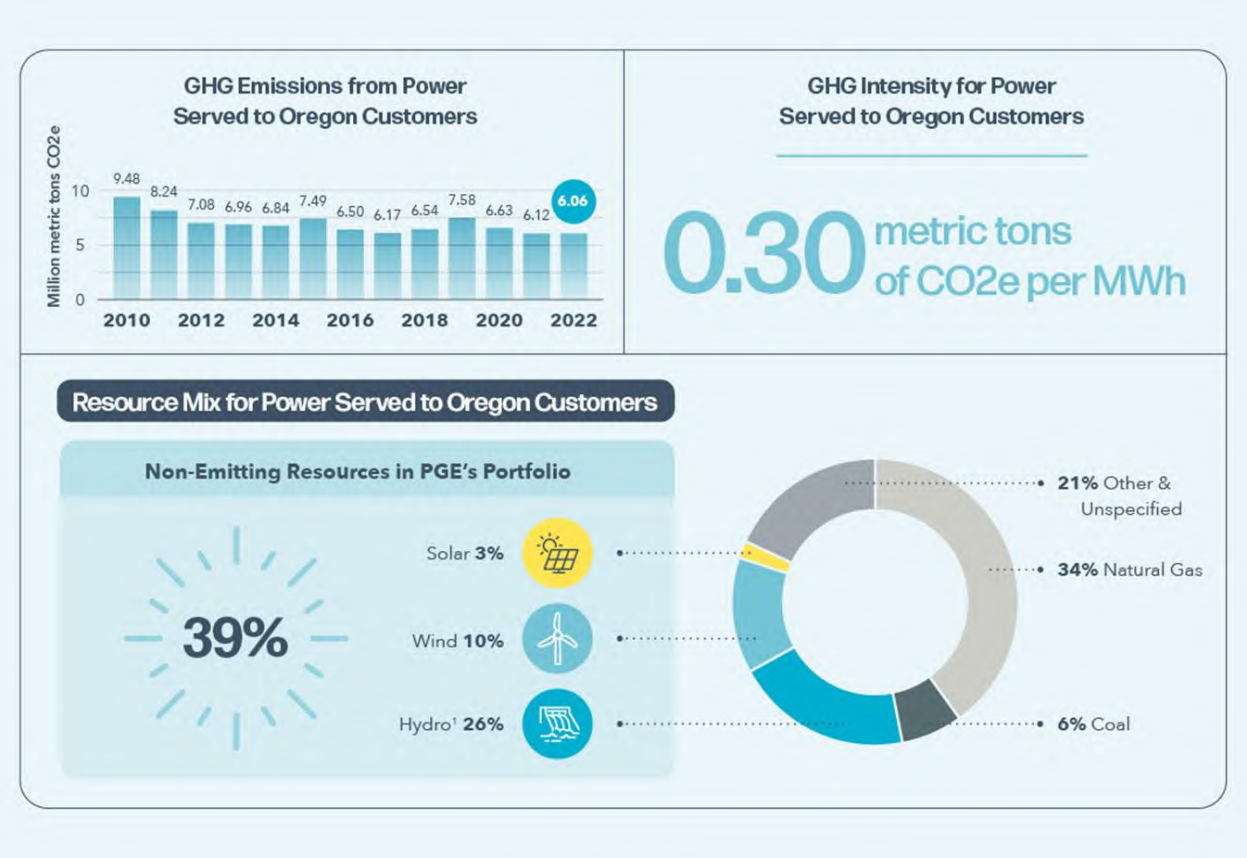
PGE's system includes more than 3,300 megawatts (MW) of generation capacity (**Figure 3**), including hydro, wind, solar, natural gas and coal. The remaining coal in our system stems from our ownership share of units 3 and 4 of the Colstrip plant in Montana. PGE also owns and operates five thermal generating units: Beaver, Power Westward Units 1 & 2, Coyote Springs and Carty, and its Westside hydro complex, including the Faraday, North Fork, Oak Grove and River Mill dams on the Clackamas, and the T.W. Sullivan dam on the Willamette. PGE also co-owns and operates the Pelton-Round Butte hydro complex in Madras with the Confederate Tribes of the Warm Springs. PGE's wind facilities include Biglow, Tucannon River and Wheatridge.

In addition to generation, PGE also purchases power to serve customers. Those purchases take a variety of forms and may include bilateral contracts (both short- and long-term) and market purchases. The GHG content associated with these market purchases is either specified (from a known source per contract) or unspecified (generation type not specified in a contract). PGE also sells surplus power to the market or to other energy suppliers in the region. Power sales can help offset power costs for customers.

PGE reports emissions from power generation and power purchased to Oregon Department of Environmental Quality (ODEQ) annually as required by OAR 340-215-0120.[9] **Chapter 5, GHG emissions forecasting**, provides a thorough overview of our emissions reporting requirements, especially as it pertains to HB 2021 compliance. In this section, **Figure 4** provides a snapshot of PGE's retail GHG emissions trends and resource mix.

[9] OAR 340-215-0120, available at: https://secure.sos.state.or.us/oard/viewSingleRule.action?ruleVrsnRsn=269300.

Figure 4. PGE emissions at a glance[10]



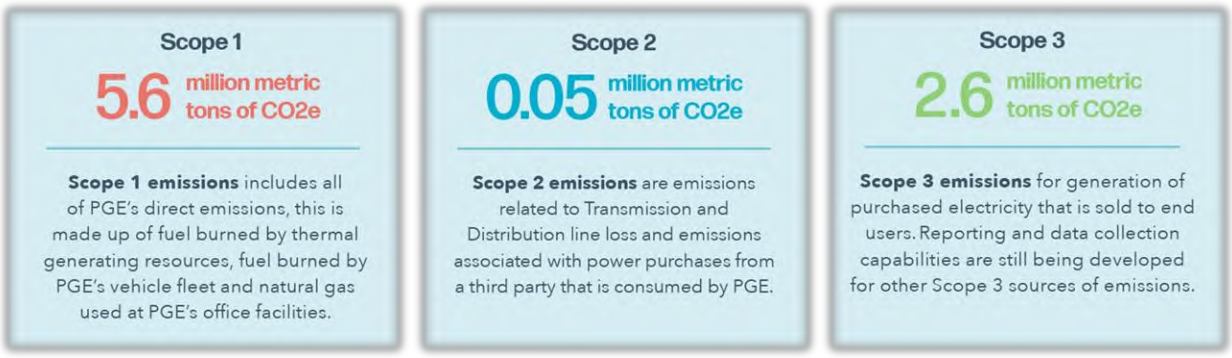
PGE is reporting 6.06 million metric tons of emissions from power generation and purchased power to service Oregon retail load in 2022. This reporting continues a downward trend in reported emissions since 2010. There will always be year-to-year variations in emissions reported due to changes in economic factors that affect load or changes in weather that affect hydro conditions, renewable capacity and peak energy needs, that are increasingly hard to forecast. It is also instructive to look at PGE's GHG emissions intensity, measured in emissions of carbon dioxide equivalent (CO2e) per megawatt hour (MWh), to show how PGE is meeting load growth in its service territory with lower emitting resources. PGE's GHG intensity has also been consistently declining in recent years, from 0.41 MT/MWh in 2019 to 0.30 MT/MWh in 2022. By 2040, PGE's GHG intensity for power associated with Oregon retail customers effectively will need to fall to zero to meet HB 2021 requirements.

[10] Figures in the graphic above are preliminary and based on energy served to retail customers within the State of Oregon, as required by the Oregon Department of Environmental Quality (ODEQ). Some or all of the renewable energy attributes associated with PGE's Basic Service Mix may be sold, claimed or not acquired. The 26% Hydro amount includes power purchased from Bonneville Power Administration. The 21% Other & Unspecified contains purchased power for which a specific generating resource is not defined and could be any of the generation types (e.g., wind, hydro, gas).

PGE lowers its reported emissions and emissions intensity by changing the portfolio of generated and purchased resources to meet Oregon retail load. In 2022, 39 percent of the power generated and purchased for Oregon retail customers came from specified non-emitting resources, primarily hydro, wind and solar. The percentage of power that was unspecified was 21 percent in 2022 and stems primarily from short-term market purchases. It is reasonable to conclude that a portion of those unspecified market purchases also came from non-emitting resources, given the surplus of solar exported from California during key intervals of the day. But because the underlying generating source is unknown for many short-term market purchases, including those occurring through the Energy Imbalance Market (EIM), ODEQ rules require PGE to assign a positive emission factor to unspecified resources, as compared to non-emitting resources which have an emissions factor of zero. PGE is committed to working with regional organizations to improve emissions tracking and accounting across Western markets to provide better visibility into the GHG content of market power.

PGE also discloses GHG emissions as part of its annual ESG reporting. In our ESG report, we disclose emissions associated with Oregon retail load, based on ODEQ methodology. We also disclose a different view on PGE's emissions using the categories of Scope 1, 2 and 3 emissions from the GHG Corporate Protocol, displayed in **Figure 5**.[11] That approach provides a wider lens on PGE's emissions than just those associated with power associated with retail customers and includes emissions associated with other areas of our operations, including wholesale operations, fleets and our buildings and facilities.

Figure 5. Scope 1, 2 & 3 emissions



The emissions regulated by HB 2021 do not directly correlate with the company's Scope 1, 2 or 3 emissions. HB 2021 applies to emissions associated with megawatts of generation and purchases for Oregon retail load. Scope 1 includes emissions from all fuels burned by thermal generating resources, whether for retail or wholesale customers, as well as fuels burned by our fleets and buildings. Power purchases for retail load are included in Scope 3.

[11] Additional information about the GHG Corporate Protocol is available at: https://ghgprotocol.org/corporate-standard.

HB 2021 only applies to a segment of our Scope 1 and 3 emissions; however, emissions associated with power generation and purchases comprise the largest portion of the company's reported emissions, accounting for 99 percent of reported Scope 1, 2 and 3 emissions. We include data on Scope 1, 2 and 3 emissions in this CEP to provide greater transparency into PGE's corporate emissions footprint.

1.2.1 HB 2021 requirements

House Bill 2021 requires PGE to reduce emissions associated with electricity sold to Oregon retail customers, with specific targets PGE must achieve on a path to 100 percent non-emitting energy by 2040. HB 2021 is a technology-neutral requirement and compliance is determined by reporting absolute emissions to ODEQ at or below target levels by 2030, 2035 and 2040.[12] Targets are determined as percentage reductions from a 2010-2012 average baseline, as specified by ODEQ. A summary of PGE's HB 2021 targets is included in **Figure 6**.

Figure 6. HB 2021 emission targets for PGE

1.3 Recent milestones in efforts to decarbonize

PGE has already taken significant steps to decarbonize its system in recent years. PGE's emissions in 2022 are already 25 percent below HB 2021's 2010-2012 average baseline level

[12] ORS 469A.410

of emissions. While additional steps, as described in this chapter, are necessary to achieve the emissions targets in 2030 and beyond, we summarize some recent milestones in our efforts to build a non-emitting resource portfolio.

All-Source RFP: In 2021, we issued an All-Source RFP for non-emitting energy and capacity resources to meet customers' energy needs. Projects that included various combinations of wind, solar, battery storage, as well as pumped storage, were evaluated throughout 2022. PGE is seeking generation resources to provide up to 250-megawatt average (MWa) of non-emitting energy and 388 MW of non-emitting capacity in this RFP. The ultimate outcome is anticipated to result in the selection of multiple projects for both renewable and capacity resources.

Clearwater Wind Project: As part of the 2021 RFP, PGE and NextEra Energy Resources, LLC., have entered into agreements to construct a 311 MW wind energy facility, which will be part of the larger Clearwater Wind development in Eastern Montana. PGE will own 208 MW of generation, with another 103 MW of output purchased through power purchase agreements. The project has an estimated commercial operation date of December 31, 2023. Located approximately 65 miles northeast of the Colstrip Generating Station, the wind farm will span Rosebud, Garfield and Custer counties in Montana.

Wheatridge Renewable Energy Facility: The Wheatridge Renewable Energy Facility is the first development of its scale in North America to co-locate wind and solar generation with battery storage. Wheatridge includes a 300-megawatt wind farm, a 50-megawatt solar facility and a 30-megawatt battery storage system, which came fully online spring of 2022. PGE partnered with NextEra Energy Resources to develop the facility. Wheatridge is in Morrow County, Oregon, the same county where PGE recently decommissioned Oregon's only coal plant in Boardman.

Boardman Closure and Decommissioning: In 2020, PGE ceased operations at Oregon's last coal-fired plant. We are now in the process of sustainably decommissioning the facility. This includes seeding 100 acres of former coal yard and other previously developed areas with native plants; salvaging and/or repurposing all parts of the plant where feasible—including rail cars, vehicles, equipment and scrap metal —to avoid waste; and turning concrete from the plant buildings into gravel or fill material at the site.

Faraday Powerhouse: PGE recently completed the rebuild of the 100-year-old Faraday dam. This is an important asset in our non-emitting portfolio that is now back in service to customers. Investment in the upkeep and maintenance of our existing portfolio is essential to meeting our decarbonization targets reliably and affordably.

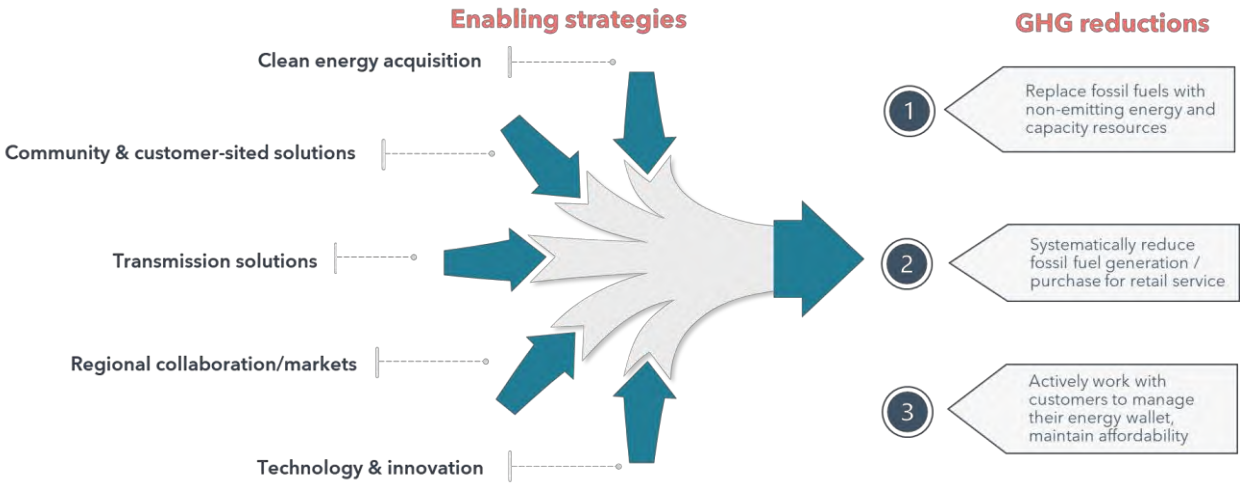
1.4 Strategies to decarbonize

Our decarbonization planning centers on customers' needs as we plan for investments in new resources and the grid that meet our emissions targets in 2030, 2035 and 2040. At the highest level, our approach to reducing emissions involves:

1. Replacing fossil fuel generation and purchases with non-emitting energy and capacity resources.
2. Systematically reducing the generation and purchase of fossil fuels for Oregon retail customers.
3. Actively working with customers to help them manage their energy use and total energy expenditures.

We bolster this approach with key enabling strategies to be able to deliver a reliable, affordable, clean energy supply, displayed in **Figure 7**.

Figure 7. Decarbonization strategies



1.4.1 Clean energy supply

Achieving our GHG targets requires gradually reducing fossil fuel generation and purchases and substituting non-emitting energy and capacity resources. Fossil fuel electric generators can provide much needed dispatchable capacity and reliability to the grid that is harder to replace with renewable energy resources alone. The sun is not always shining, and the wind is not constantly blowing. Batteries can offer energy storage on a finite basis, but prolonged weather events that inhibit wind and solar generation, as exhibited in recent years, can also deplete battery capacity. A reliable grid must be resource adequate, with enough capacity and reserves to maintain balanced energy supply and demand to meet peak energy needs at

any time and under all weather conditions. For these reasons, as PGE looks to replace fossil fuel generation and purchases with renewables and storage, it will need geographic and resource diversity.

Identifying the Preferred Portfolio of non-emitting energy resources for PGE's system is the fundamental responsibility of the IRP, developed in later chapters of this filing. The IRP provides critical foundations for our CEP. The IRP estimates our system resource need by forecasting long-term demand growth and comparing it to projected generation from existing and contracted assets. The IRP then models the pathway to fill those resource needs, by evaluating resource options and determining the optimal size and timing of resource additions in different portfolios. The analysis results in a Preferred Portfolio of resources and a detailed Action Plan for the company to follow over the next 2-4 years. That Preferred Portfolio and Action Plan become the basis and rationale for the Company's clean energy procurement, including potential contract renewals and RFPs. This year's IRP optimizes the resource portfolio subject to the GHG emissions constraints introduced by HB 2021 and includes other important modeling innovations related to transmission, resilience and community benefits to reflect the Commission's feedback on our 2019 IRP, new Commission guidelines stemming from Docket UM 2225 and stakeholder and community feedback.[13]

To inform the resource path to 2030 emissions targets, the current IRP examined the following list of resource options that are currently known and at commercial scale in our region:

- On-shore wind: OR Gorge, SE Washington, Montana, Wyoming
- Solar: Central OR, OR Gorge, Willamette Valley, Desert SW
- Battery Storage: Lithium Ion, multiple durations
- Hybrid: Solar + Battery Storage
- Pumped Storage Hydropower
- Distributed energy resources
- Energy Efficiency (EE)
- CBRE (community scale solar, solar + storage microgrids, in-conduit hydro)

Beyond 2030, other non-emitting technologies like hydrogen, nuclear, carbon capture or long duration storage may prove cost-effective for serving customers in our region. These technology options are explored in greater detail in **Chapter 8, Resource options**.

[13] See *In the Matter of Public Utility Commission of Oregon, House Bill 2021 Investigation into Clean Energy Plans,* Docket No. UM 2225, Orders available at: https://apps.puc.state.or.us/edockets/DocketNoLayout.asp?DocketID=23160.

The IRP in **Chapter 6, Resource needs** describes the estimated capacity need in 2030 to be 1136 MW in summer and 1004 MW in winter. It forecasts an energy need of 905 MWa by 2030, which is roughly equivalent to 2,500 MW of non-emitting energy resources, depending on the capacity factors of those resources. This projected resource and capacity need is in addition to the 1,000 MW of non-emitting resources currently being pursued through the 2021 All-Source RFP. This means that by 2030, PGE may need to procure and integrate between 3,000-4,000 MW of non-emitting resources and capacity to meet customers' energy demands and our 2030 emissions target. Policy and market changes could change this estimated need by 2030, but the work in the near term is the same: we need to procure clean energy resources and capacity at an accelerated pace through one or more RFPs to achieve our first emissions target in 2030. To put the challenge in perspective, PGE currently operates 3,300 MW of owned and contracted assets (shown in **Figure 3**). As discussed further in **Chapter 3, Planning environment** and **Chapter 4, Futures and uncertainties**, the procurement of this quantity of non-emitting resources will be complicated by persistent supply chain and labor market challenges, as well as general competition for non-emitting resources against the backstop of a rapidly decarbonizing Western Interconnect (see **Section 4.1, The changing Western Interconnection**).

As clean energy resources and capacity come online between now and 2030, PGE can systematically replace the use of fossil fuel generation and purchases for Oregon retail customers. PGE began this transition from fossil fuels years ago. We closed Oregon's only coal fired plant, Boardman, in 2020, a first of its kind agreement to consider closure as a form of pollution control. We continue to evaluate the timing and conditions of exiting ownership of Colstrip Units 3 and 4 as part of meeting our regulatory and legislative requirements. As we look to the future, we expect to evolve operations of our thermal fleet, which includes some of the highest efficiency natural gas plants in the nation, to provide for reliability during periods of grid stress when clean energy resources are scarce relative to demand and to meet resource adequacy requirements. We will continue to maintain the efficiency and safety of these facilities, making upgrades as necessary for efficiency, safety and air quality.[14] We may also explore the potential to transition thermal generation to cleaner fuels, such as hydrogen, to replace natural gas combustion in those units.

1.4.2 Community and customer-sited solutions

As IRP portfolio analysis demonstrates, achieving targeted emissions levels reliably and affordably will require a diversity of resource options, not only utility-scale wind, solar and

[14] PGE entered into agreement with ODEQ in August 2021, agreeing to reduce permitted emission levels of nitrogen oxides, sulfur dioxide and particulate matter at the Beaver/Port Westward 1 plant. The combined total of permitted emission levels for these three pollutants will be reduced by 85 percent from 2021-2025.

battery resources. DERs, CBREs and a virtual power plant (VPP) to better support the utilization of DERs and CBREs, are important components of our decarbonization strategy, and they will enable customers and communities to play an important and growing role in the transition to a clean energy grid. As our award-winning track record of customer participation in our voluntary renewable energy programs attests, many customers are already choosing clean energy now. We are also proud to serve many municipal, commercial and industrial customers who have publicly established very ambitious sustainability and climate goals. Decarbonizing our power supply facilitates attainment of their clean energy goals. DERs and CBREs, however, are not only resources and programs that many customers want. They are also resources that can help us meet our energy and capacity needs as we decarbonize, especially given transmission limitations for new bulk system resources as described in **Chapter 9, Transmission**.

The grid of the future will be increasingly smart and adaptive, allowing for improved two-way energy transfers, which means customers can save money as we continue to work with them on energy efficiency programs, rooftop solar, battery storage and electric vehicle charging. For example, through our smart grid connected appliance programs, customers can automatically adjust their energy use. Our customer offerings aim to benefit both participating and non-participating customers, support grid reliability and help manage overall power costs.

Programs that help customers reduce their energy usage or incentivize customers to match their energy usage to times when clean resources are most abundant on the grid not only save customers money, but they can also hasten the transition to cleaner energy resources by replacing the need for fossil fuel standby generation. On extreme temperature days, or when unanticipated weather or other events pull generation assets offline, PGE can harness the flexibility of demand response programs and DERs to meet peak energy demand. By 2030, PGE aspires to be able to meet as much as 25 percent of the energy needed on the hottest and coldest days with power coming from customers and DERs.

We anticipate growing our flexible load portfolio, and we are already experiencing significant growth in EVs on our system. There are currently approximately 61,000 electric vehicles registered in Oregon, and the state has aggressive goals of adding 250,000 registered zero emissions vehicles statewide by 2025 and even larger goals by 2030. We continue to collaborate with the Energy Trust of Oregon (ETO) on local, community-driven smart grid technology learning programs, including the Smart Grid Test Bed (SGTB) and Smart Grid Advanced Load Management & Optimized Neighborhoods (SALMON) projects, funded through the Department of Energy. The SGTB collaboration is expected to continue through 2026 and will include a solarize campaign, as well as flexible feeder, smart inverter and battery pilots. The SALMON initiative is expected to continue through mid-2027 and includes the retrofit of approximately 580 buildings in North Portland with technologies such smart thermostats, smart water heaters, solar with smart inverters, storage and managed electric

vehicle charging, with a focus on bringing benefits to low-income and environmental justice (EJ) communities within the SGTB.

We offer and continue to build our residential smart battery storage pilot which contributes up to 2.4 MWh of energy to support various grid services. We have been working with municipalities to pair energy storage batteries with rooftop solar and municipal electric vehicle charging. We are also working with transit providers and school systems on bus charging on-route and at the depot. In partnership with Daimler Truck North America, we continue to invest in large truck charging including pairing MW size chargers with co-sited batteries at the Electric Island facility. In 2022, we launched a fleet charging pilot and will look to continue this engagement in 2023.

Weather events, and delays in procurement timelines, including supply chain disruptions, could result in the region experiencing challenges meeting peak customer electricity demand in the next several years, particularly in the summer months. During this transition and when periods of emergency arise, utilities need the flexibility to access all available resources to meet increasingly uncertain peak load demands. Last year, the Commission approved a revision to our tariff to allow the addition of batteries into our Dispatchable Standby Generation (DSG) program. We are working with customers who are installing battery storage to be able to draw upon those batteries at peak times as we have historically done with existing customer-owned emergency generators. While the program is still only a few months old, we already have seven interested customers making up 14 MW of potential power. This is why our DSG program continues to be an essential resource even as we transition to clean electricity and add more non-diesel reserves. Our DSG program consists of 130 MW (as of this filing) of dispatchable contingency reserve in the form of diesel emergency backup generators. We have been experimenting with a new type of renewable diesel sourced from plant waste byproducts called R99 (99 percent renewable diesel) and have already rolled it out to our largest customer with hopes for additional customer adoption in the future.

Energy efficiency is an important component of PGE's decarbonization strategy, as a mechanism to reduce load while helping customers save on their energy bills. As detailed in **Chapter 12, Action Plan**, PGE plans to acquire all cost-effective energy efficiency, which is currently forecast by ETO to be 150 MWa on a cumulative basis through 2028. The Action Plan also calls for PGE to enroll 211 MW summer and 158 MW of winter customer demand response by 2028.[15]

In addition, as per UM 2225 guidelines, the IRP also evaluated CBREs. CBREs, as modeled in the IRP, are smaller scale, less than 20 MW, distribution-connected resources that can provide a wider range of community benefits including resiliency and bill savings for customers.

[15] Demand response values include existing programs.

CBREs as described in **Section 7.2, Community-based renewable energy (CBRE)**, could include standalone community-scale solar photovoltaic resources, solar paired with storage microgrids for resilience, and small low-impact hydro opportunities. We have established a target for CBRE acquisition of 155 MW by 2030. The Action Plan calls for 66 MW of CBREs by 2026.

DERs and CBREs, especially when combined as microgrids, can provide timely system capacity support, resiliency for the community and avoid disruptions to customer service. To ensure that these resources can contribute both the energy and capacity we need, we are investing in improved DER utilization through our development of a VPP with capabilities to support our clean energy transition, discussed in greater detail in **Section 8.4, Virtual Power Plant (VPP)**. A VPP is effectively a power plant consisting of DERs and flexible loads, orchestrated through a technology platform to provide grid and power operations services. We anticipate that changes in DER and energy efficiency program design and rate structures will also be necessary to support expansion of these resources in ways that provide grid benefits for all customers and distribute costs fairly.

We are actively planning for and investing in ways to equitably modernize our distribution system, while improving safety, reliability and reducing emissions. Building an equitable clean energy future will require intentional placement of resources like batteries, electric vehicle (EV) chargers and solar panels throughout Oregon communities. To plan for the smart grid and make its benefits available to all PGE customers, we collaborated with community-based organizations and stakeholders on Part I and II of our DSP, filed at the OPUC.[16] Our DSP is an integral step toward creating a 21st-century community-centric distribution system that can support decarbonization.

1.4.3 Technology and innovation

As we look to the future and our target to reduce emissions by 100 percent by 2040, we are embracing innovation and preparing to adopt and scale cost-effective clean energy technologies to benefit customers. A 100 percent emissions-free grid will require infrastructure upgrades and new resources, storage and grid technologies to maintain resource adequacy and affordability for customers. As discussed in **Chapter 2, Accessing support for energy transition**, passage of the Inflation Reduction Act (IRA) and Infrastructure Investment and Jobs Act (IIJA), as well as ongoing efforts at the federal and state levels to streamline the siting of new energy resources, can accelerate the expansion of non-emitting resources across the West, including longer duration batteries, pumped storage, floating offshore wind, nuclear and hydrogen technologies. We are working with Federal and State

[16] PGE's DSP available at: Distribution System Planning | PGE (portlandgeneral.com).

governments, Tribes, peer investor-owned utilities and other technology experts to drive innovation and leverage available incentives (IRA and IIJA) to accelerate the development and ultimately reduce the cost of these new technologies, as well as micro-grids, advanced artificial intelligence (AI), grid edge autonomous operations, communications systems, and infrastructure upgrades and system hardening including transmission, distribution and hydro generation.

Our Integrated Operations Center (IOC), which finished its first full year of operations in 2022, is fulfilling its role as the nerve center for an increasingly complex and intelligent energy network. It integrates grid-connected assets and devices, whether consumer, utility or third-party owned – while coordinating and optimizing the flow of energy and information across the system.

As previously discussed, we are expanding our VPP capabilities to support our clean energy resource and capacity needs by leveraging customers' participation in demand response, solar, battery storage, electric vehicles and distributed energy generation programs. We discuss the VPP in greater detail in **Section 8.4, Virtual Power Plant (VPP)**. The new capabilities of our IOC and other smart grid investments provide the data, system visibility and insights to optimize resources under constantly changing conditions. More importantly, these advancements help accelerate customers' clean energy transformation by leveraging the scale and diversity of West-wide generation and transmission.

1.4.4 Regional solutions to resource adequacy: markets, partnerships and transmission

To achieve GHG targets, PGE will need access to a wider geographic area to source and site resources and a broader technological diversity of resources. That is why PGE is collaborating in innovative new ways across the Western Interconnection. From participation in the expansion of regional markets to coordination on resource adequacy to transmission planning, PGE, like other utilities across the West, is working across the energy system in the West to deliver better value and enhanced reliability as we and the region decarbonize.

This regional expansion is occurring against the backdrop of a rapidly evolving power system landscape across the Western Interconnection, as discussed in **Chapter 4, Futures and uncertainties**. In 2018, no Western states had policies mandating 100 percent clean or a non-emitting power system. Today, Oregon, Washington, California, Nevada, Arizona, New Mexico, Colorado and Idaho have state regulations and/or utility-specific goals requiring 100 percent clean or non-emitting power (shown in **Figure 17**). These policies will likely accelerate the transition from coal and natural gas fired generation to wind, solar, storage and other non-emitting resources. This rapid decarbonization will increase pressure on suitable locations for siting new resources, as well as on the transmission infrastructure

required to deliver that power to load. These policies also highlight the need for regional coordination of planning to mitigate situations of utilities becoming energy-long or risking curtailment due to economics or lack of transmission.

Renewable penetration and retirement of fossil fuel plants require higher volumes of dispatchable power and capacity requirements. As a result, resource adequacy challenges have occurred in recent years in the Western Interconnection. In California, the California Independent System Operator (CAISO) system was forced to implement rotating power outages in August 2020 and issued a Stage 3 emergency alert in September 2022 due to an unprecedented extended heat wave. Prior to 2020, CAISO had not issued a Stage 3 alert since the 2001 energy crisis. Due to reliability concerns, California has created an electric reliability reserve fund and extended the life of the Diablo Canyon nuclear power plant for grid reliability purposes.

Climate change has ushered in new climatic patterns such that historical data cannot inform future summer and winter energy peaks as reliably. Weather events with 1-in-100-year frequency are occurring more regularly. Customer energy usage is also evolving in response. For example, the June 2021 heat dome event in Oregon led to a significant uptick in the number of air conditioners in residences. But recent data also suggest that not only do more customers have access to air conditioning, but they may be using air conditioners differently, running it more consistently over multiple days. At the same time, public policy across the West is encouraging and/or mandating building and vehicle electrification as discussed in **Chapter 3, Planning environment**, bringing new loads to the Western Interconnection. Our region is also experiencing significant load growth from data centers, crypto operations and the expansion of other energy-intensive industries like semiconductor manufacturing.

When resource adequacy challenges occur, they have implications across the Western Interconnect. For example, during the September 2022 heat event in California, generation assets across the Western Interconnect were operating at capacity to avoid power outages. PGE's generating assets play an important role in supplementing regional resource adequacy. At the same time, generating assets across the Western Interconnect contribute to the reliability and resource adequacy of our system. For this reason, in December 2022, we announced our intent to participate in the Western Resource Adequacy Program (WRAP) through the Western Power Pool (WPP), a proactive step to protect the reliability of the power supply for customers while we actively transition to non-emitting resources, as discussed further in **Chapter 3, Planning environment**. This is a critical step in our strategy to decarbonize.

So too is PGE's continued participation in the Western EIM, a west-wide real-time energy trading market in partnership with the California System Operator (CAISO) that has lowered power costs significantly for customers over five years. PGE is actively engaged with regional market expansion activities that would extend the benefits of the EIM to the Energy Day-

Ahead Market (EDAM). Regional energy markets like EIM and EDAM effectively expand our resource footprint, allowing PGE access to a wider diversity of resources as we and other regional utilities decarbonize. Markets deliver cost-savings and reliability benefits by economically dispatching participating utilities' generation assets to balance supply and demand over a wider geographic region. This enables greater renewable penetration and integration across the West while reducing the need for stand-by fossil fuel generation. Markets, therefore, facilitate decarbonization efforts and can lower the overall GHG intensity of power traded across the Western Interconnect.

Market design, however, will need to be carefully considered to account for disparate GHG policies and accounting requirements across Western states. The real-time nature of the market means that energy is dispatched where it is most economically valued at a point in time. When PGE participates in the EIM, or in other short-term market transactions, the power it imports is typically considered "unspecified" according to ODEQ's GHG reporting requirements in OAR 340-215-0020. Since the underlying generating resource is unknown, ODEQ's rules assign a positive emissions rate to those unspecified megawatts to reflect emissions from fossil fuel generating assets operating across the Western Interconnect. This means that PGE's participation in the EIM, and potential future participation in EDAM, will result in reporting GHG emissions from unspecified market purchases to ODEQ. CAISO has begun conversations with participating utilities through workshops and other venues to develop better market rules for tracking and attributing carbon to enhance regional decarbonization efforts and facilitate utility-specific compliance with different state GHG policies and requirements.

Beyond markets, PGE is also pursuing other beneficial regional collaboration opportunities. Our contract with Douglas Public Utility District provided 150 MW of non-emitting hydro capacity, while supporting our partners with our systems operation technology. Finally, our portfolio analysis demonstrates that additional transmission options are needed to access the diversity of non-emitting resources required to reliably meet our emissions targets, given the known constraints to Bonneville Power Administration's (BPA's) transmission system. As discussed in **Chapter 9, Transmission**, and outlined in **Chapter 12, Action Plan**, PGE will continue assessing potential transmission options that provide the best customer value. These policies also highlight the need for regional coordination of planning to mitigate situations of utilities becoming energy-long or risking curtailment due to economics or lack of transmission.

1.5 Pathway to HB 2021 emissions targets

Section 1.2, Historical emissions trends and resource mix, describes PGE's historic and current emissions, resource mix, GHG intensity and our HB 2021 emission targets. In **Section 1.3, Recent milestones in efforts to decarbonize**, we describe some of the significant

actions that PGE has already taken to decarbonize. At the close of 2022, PGE had already reduced emissions by 25 percent from the HB 2021 established baseline.

In **Section 1.4, Strategies to decarbonize**, we describe our high-level approach to decarbonize, which involves gradually reducing fossil fuel generation and purchases for Oregon retail customers and replacing it with non-emitting energy resources and capacity, as well as key enabling strategies to facilitate a reliable and affordable transition. We also discussed the important and interrelated role of the CEP and IRP. The IRP estimates PGE's energy and capacity needs subject to HB 2021 emissions constraints. It creates a Preferred Portfolio of resources to meet those needs and details an Action Plan to guide the company's procurement and related resource actions over the next 2-4 years.

One of the CEP's primary objectives is to detail PGE's path to compliance with the HB 2021 targets. It should show that the Preferred Portfolio and Action Plan that PGE has developed in its IRP are consistent with "no-regrets" steps the company should take in the near-term to be able to meet emissions targets in 2030, 2035 and 2040, according to the best methods available at the time. Moreover, it should describe how the company will demonstrate continual progress toward those targets. In this section, we describe how our strategies described in **Section 1.4, Strategies to decarbonize** and the Preferred Portfolio and Action Plan developed in the IRP in subsequent chapters, inform a path to the required emissions targets that balance affordability and reliability for customers. More details on modeling specifics can be found in those chapters and the appendix to this document.

1.5.1 Portfolio analysis and Action Plan

The IRP estimates an energy need of 905 MWa by 2030 and a 2028 capacity need of 624 MW in the summer and 614 MW in the winter. To achieve our emissions target by 2030, all the resources acquired to meet these energy and capacity needs will have to be non-emitting. Integration of these resources onto our system will enable a systematic reduction in fossil fuels serving Oregon retail load and subsequent GHG reductions. As described in **Chapter 11, Portfolio analysis**, IRP portfolio analysis determines the best set of resource types and quantities to meet energy and capacity needs under different scenarios. This informs the creation of the Preferred Portfolio, the company's Action Plan and the path to HB 2021 emissions targets described in this section.

PGE addressed six key questions consistent with HB 2021 compliance in our portfolio analysis. The answer to these questions provides key insights for balancing cost, risk, community benefits and the rate of GHG reduction to achieve HB 2021 targets. Those questions include:

- At what pace should PGE reduce emissions?
- Which resource actions maximize community benefits?

- Will CBREs lower system costs?
- Should PGE pursue energy efficiency and demand response beyond what is planned and cost-effective?
- Is there sufficient transmission available to meet HB 2021 targets?
- Do transmission expansion options allow PGE to meet system needs at the lowest cost?

To answer these and related questions, PGE evaluated 39 different portfolios across seven categories of portfolio options (see **Table 1**). All portfolios meet HB 2021 emissions targets.

Table 1. List of portfolio categories and their purpose

Portfolio categories	Purpose
Transmission	Study the need for transmission, the timing of this need, and the corresponding magnitude needed over time to reliably decarbonize.
CBRE	Explore the relationship between costs, risk and community benefits.
Additional EE and DR	Determine if and how the role of these resources could change with the changing planning environment.
Optimized	Explore the relationship between minimizing costs in the short-term and the entire planning horizon and the cost of constraining the model.
Targeted policy	Inform stakeholder discussions on specific policy questions.
Emerging technology	Understand the potential impacts of emerging technologies.

The insights gleaned from the construction and comparison of these 39 different portfolios informed the creation of PGE's Preferred Portfolio and our balanced path to HB 2021 emissions targets. Specifically, we found that:

- Amongst the five decarbonization glidepath scenarios evaluated, a linear emissions glidepath best balances costs, risks and the rate of GHG reduction. Cumulative emissions reduction would be higher under scenarios that either front-loaded reductions in the early years, or accelerate GHG targets forward in time, but at additional risk and cost to customers. Alternatively, delaying emissions reduction until 2030 lowers estimated costs but incurs risks that PGE will not meet its targets because of procurement delays or supply

chain constraints, increased uncertainties in available transmission inventory, and operational risks associated with adding large quantities of resources in a short period.

- Transmission is a very significant factor impacting the economics and timing of resource additions to PGE's system. The need for new on- and off-system transmission options is significant and will be required for PGE to achieve the HB 2021 targets reliably. The reality of these transmission constraints makes additional customer-sited solutions like energy efficiency, demand response and CBREs more competitive in portfolio analysis.
- Given these transmission constraints, selecting 100 percent of the CBRE technical potential (155 MW by 2030) lowers customer costs and risks while maximizing community benefits.
- Pursuing 100 percent of the cost-effective energy efficiency and demand response available minimizes costs and risks for customers. While additional increments of energy efficiency and demand response may lower long-term costs compared to alternative resource options, there are near-term price impacts and additional risk associated with procuring this additional energy efficiency and demand response in the current policy and market environment.

These findings, summarized in **Figure 8**, comprise the rationale for PGE's Preferred Portfolio.

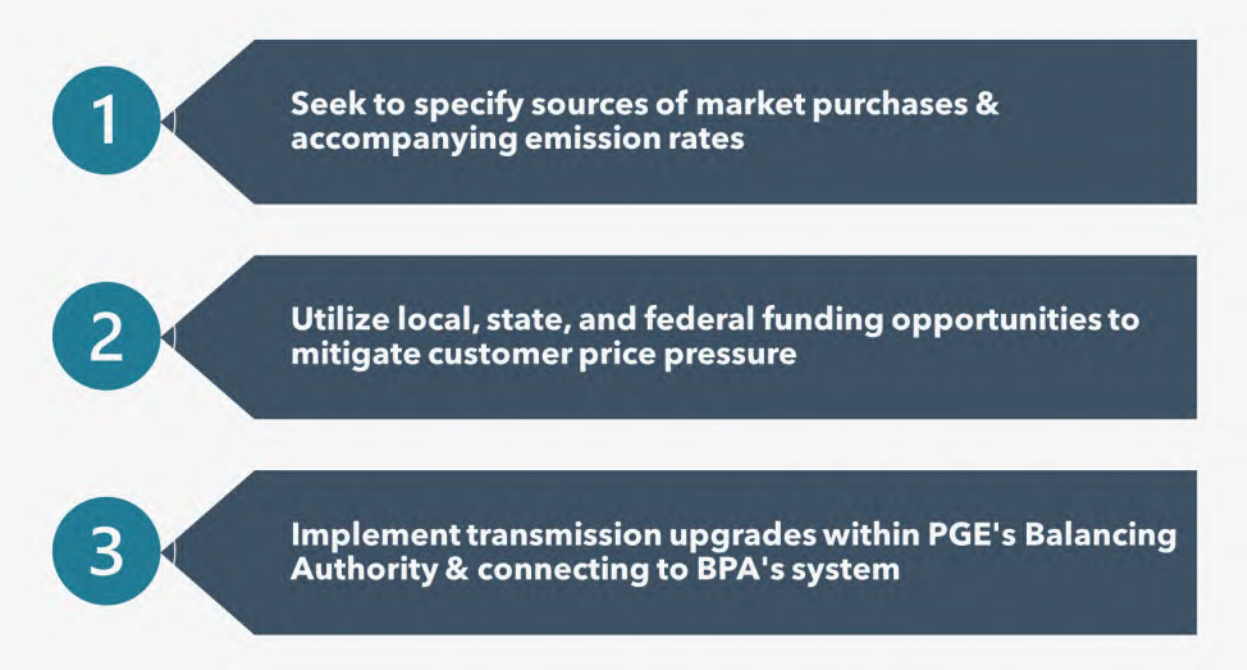
Figure 8. Key findings for the Preferred Portfolio

PGE built its 2023 Action Plan based on these findings from portfolio analysis and the Preferred Portfolio. The Action Plan, shown in **Figure 9**, is the best set of near-term "no-regret" resource options the company intends to take to reliably build towards HB 2021's emissions targets while minimizing costs.

Figure 9. Action Plan

In addition to the resources being pursued in the Action Plan, PGE is taking steps to meet resource adequacy and emissions targets at the least possible cost and risk. These additional actions are shown below in **Figure 10**.

Figure 10. Additional steps



1.5.2 Pathway to emissions targets

PGE's Preferred Portfolio represents the best set of incremental resource additions that balance cost and risk for customers while achieving HB 2021 emissions targets. Now we translate that analysis into emissions reductions planned for our system between now and 2030, and from 2030 to 2040.

If PGE is successful in acquiring these resources and taking related resource actions, it will be able to replace fossil fuel generation and purchases with non-emitting alternatives at a pace and scale sufficient to reduce emissions below HB 2021 targeted requirements. For planning purposes, our modeling assumes a linear decline in emissions associated with retail sales between 2026, when incremental IRP resources first become available, and 2030. It then plans a linear decline in emissions from 2030 to the zero emissions target in 2040. Between 2022-2026, emissions on PGE's system are expected to decline due to planned resource actions, including incremental resource additions stemming from the 2021 All-Source RFP.

Though PGE uses a linear glidepath for emissions reduction for planning purposes, PGE will measure annual progress in megawatts of non-emitting resources added to our system rather than in tons of emissions reductions for two reasons. First, emissions reductions are predicated on adding non-emitting resources and capacity to reduce thermal generation and purchases for meeting load and resource adequacy requirements. Second, actual emissions reported to ODEQ between now and 2030 will exhibit year-to year variation, due to factors

like weather that impact hydro conditions, renewable capacity and peak loads or other events that the utility could not reasonably forecast or control.

PGE is planning for accelerated procurement through one or more RFPs between now and 2030. We expect annual acquisition and integration of non-emitting resources and have planned for a resulting annual decline in reported emissions, holding weather and other variables constant. However, the realities of market procurement, transmission and system integration may instead lead to step-changes in resources becoming available to PGE customers and resulting emissions reduction between now and 2030. From a planning perspective this is still consistent with our 2030 target. Our work to further develop the VPP to enhance utilization of DERs and CBREs will continue in parallel over this time frame.

Figure 11 details the incremental resource actions by year and annual decline in emissions planned between now and 2030. The incremental resource additions in the Preferred Portfolio are shown in **Table 2**.

Figure 11. Preferred Portfolio resource pathway through 2030

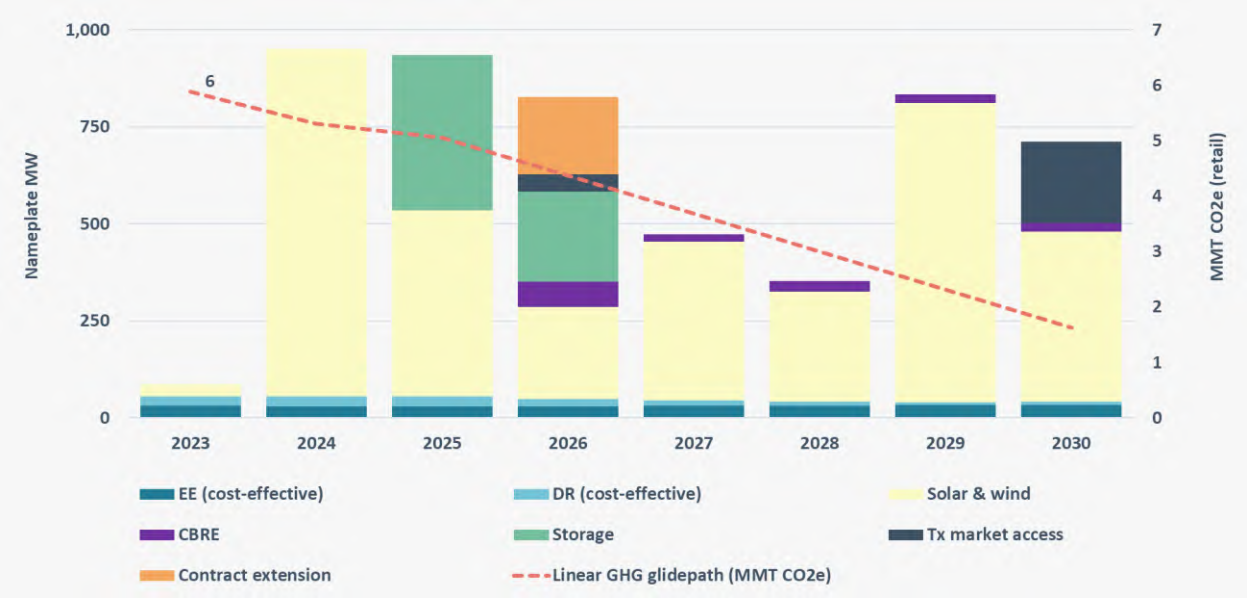


Table 2. Preferred Portfolio resource pathway through 2030[17]

Values in nameplate MW	2023	2024	2025	2026	2027	2028	2029	2030
DR (cost-effective)	24	26	25	19	14	11	8	9
EE (cost-effective)	31	30	30	30	30	31	33	33
Storage	0	0	400	232	0	0	0	0
Solar & wind	31	894	479	237	410	284	770	438
CBRE	0	0	0	66	19	26	23	22
Transmission (Tx) market access	0	0	0	44	0	0	0	211
Contract extension	0	0	0	200	0	0	0	0
GHG glidepath (MMTCO2e)	5.9	5.3	5.0	4.4	3.7	3.0	2.3	1.6

As the table and graph indicate, PGE anticipates being able to meet its 2030 target using resources that are currently known and commercially available. Between now and 2030, PGE's thermal fleet is continuing to economically dispatch, as it does presently, to meet resource adequacy and cost-minimization for PGE's customers and the region. As PGE adds non-emitting energy and capacity resources, it anticipates systematically reducing the amount of thermal output from natural gas and coal for Oregon retail load to meet emissions targets (see **Figure 12**). The market for thermal generation is increasingly constrained across the West, as discussed earlier, with clean energy or GHG requirements in place in almost every state in the Western Interconnect. Thermal generation sold into the Western Interconnect is therefore likely subject to the GHG or clean energy requirements of other states. For example, fossil fuel energy exported to California and Washington incurs direct carbon pricing obligations. Public policies like this, and the massive buildout of non-emitting resources anticipated across the region, lowers economically dispatched thermal output in our forward modeling.

[17] Cost-effective estimates of DR and EE in this table reflect incremental additions in each year

Figure 12. GHG emitting resources for retail load 2023-2030

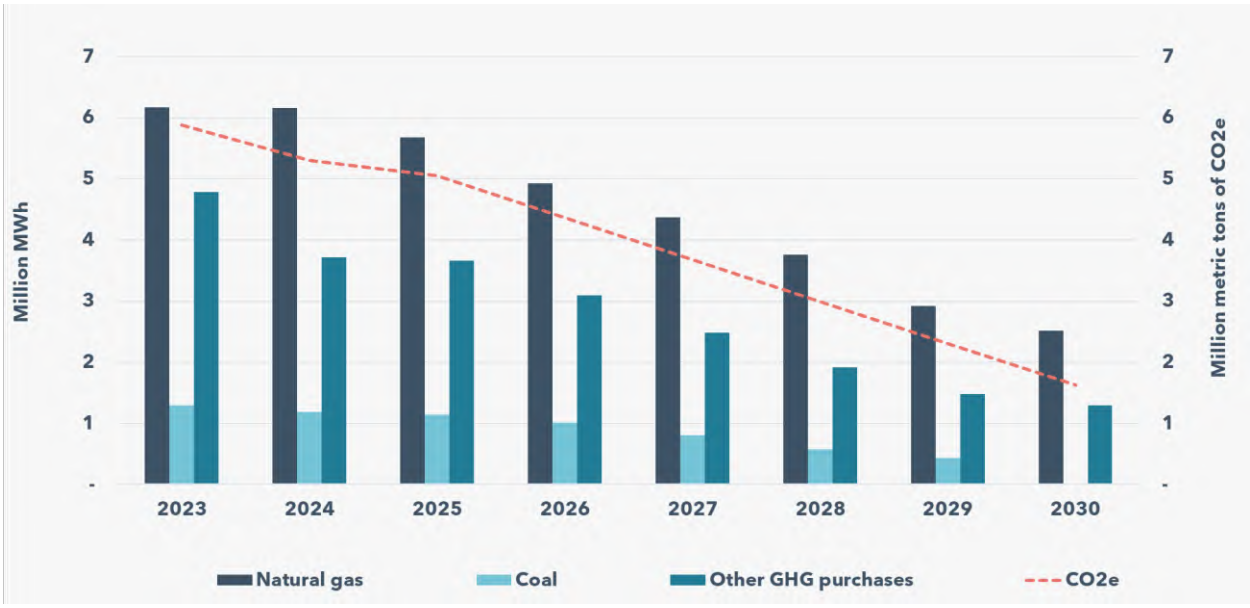


Table 3 and **Figure 13** display the longer-term resource additions in the Preferred Portfolio. As we look beyond 2030 to the 90 percent emissions reduction requirement in 2035 and the zero-emission requirement by 2040, two things become apparent. First, there is a need for additional dispatchable effective non-emitting capacity resources to be developed and available to us in our region to meet resource adequacy needs. The model effectively holds a place for a new non-emitting capacity resource by using two generic resources that provide the necessary capacity and energy for the model to meet reliability needs once transmission-constrained proxy resources have been exhausted, the need for which becomes larger the closer we come to 2040. That resource may be a new resource, currently commercially unavailable, like hydrogen, advanced nuclear or advanced geothermal, or an existing resource that becomes more cost-competitive over time, like longer-duration batteries or pumped storage. Second, part of the effective capacity need leading into 2040 could potentially be offset by existing thermal plants if they are able to transition to non-emitting fuels by 2040. It is possible that if supplies become commercially available sooner, PGE's thermal fleet could combust hydrogen or an alternative low-carbon fuel sooner. Almost all of PGE's existing thermal fleet is capable of combusting a blend of hydrogen or renewable natural gas at present.

Figure 13. Preferred Portfolio resource pathway 2031-2043

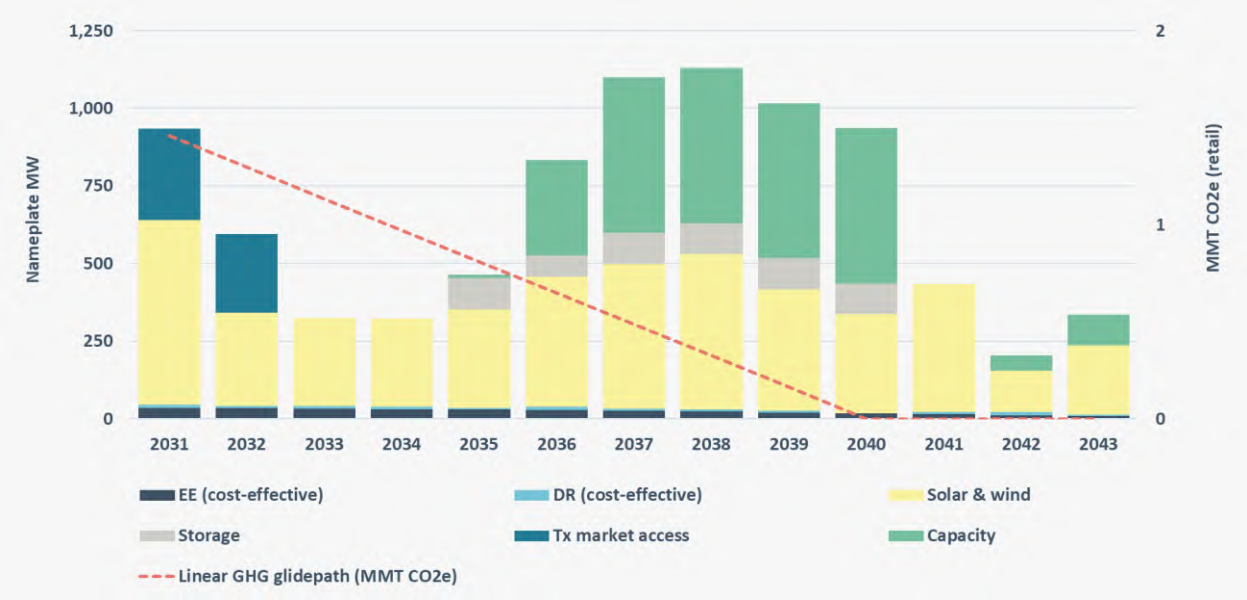


Table 3. Preferred Portfolio resource pathway 2031-2043 (detail)

Values in nameplate MW	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
DR (cost effective)	11	8	9	8	5	11	7	7	7	1	6	11	3
EE (cost effective)	34	34	32	31	29	28	25	23	19	16	15	11	9
Storage	0	0	0	0	100	68	100	100	100	100	0	0	0
Solar & wind	596	301	282	284	319	419	467	500	391	320	414	132	224
Tx market access	293	252	0	0	0	0	0	0	0	0	0	0	0
Capacity	0	0	0	0	13	309	500	500	500	500	0	50	99
GHG glidepath (MMTCO2e)	1.5	1.3	1.1	1.0	0.8	0.6	0.5	0.3	0.2	0.0	0.0	0.0	0.0

1.6 High-level opportunities, potential barriers, critical dependencies

In this section we discuss our compliance path in terms of the opportunities, challenges, critical dependencies and barriers we may confront. Our ability to decarbonize highly depends on acquisition and integration of non-emitting energy and capacity resources. PGE cannot reduce fossil fuel generation and purchases without the energy and capacity to replace it. As we discussed previously, PGE is pursuing different strategies to increase the likelihood that we can replace fossil fuel generation and purchases from emitting and unspecified sources on the timeline we need to meet our emissions targets. We will pursue large, non-emitting supply-side resources and the transmission options necessary to support them; we will continue our work to develop a VPP and deploy energy efficiency and demand response to reduce and actively shape load; we will work with communities to develop CBREs; and we will leverage technology, regional partnerships and markets to access a wider diversity of resources to balance reliability and costs for customers. Changes in the macroeconomy, markets, technology, the regional energy economy, federal and state policy incentives, and customer demands can either facilitate or delay the strategies we have identified. These risks and uncertainties are discussed further in **Chapter 2, Accessing support for energy transition, Chapter 3, Planning environment**, and **Chapter 4, Futures and uncertainties**.

Between now and 2030, there are clear, "low regrets" near-term actions that will be integral contributors to our future decarbonization portfolio regardless of future uncertainties. These are largely the actions articulated in our Action Plan. There is no path to an 80 percent emissions reduction on PGE's system that does not involve a significant buildout of non-emitting energy storage and renewables. This includes DERs, including distribution system connected CBREs, which have the advantage of not requiring additional transmission and provide grid and community benefits, and our efforts to improve utilization of flexible loads, through the VPP. As we look to acquire these resources, we will seek federal support and all of the benefits of federal policy such as the Inflation Reduction Act (IRA) or the Investment Infrastructure and Jobs Act (IIJA) for customers, as discussed in **Chapter 2, Accessing support for energy transition**.

In terms of transmission, we also consider the South of Alston (SoA) line congestion relief and upgrades to the Bethel-Round Butte line as "no-regrets." There is very little time between now and 2030 to acquire and integrate the scale of non-emitting resources necessary to offset fossil fuels, so a strategy that prioritizes moving forward with technologies that are commercially available today is the only plausible pathway to our targets. We will be moving forward on all these strategies simultaneously in an accelerated procurement cycle to support our success. We also anticipate negotiating contract renewals to maintain contracted

non-emitting resources in our portfolio. We plan to pursue 100 percent of the demand response and energy efficiency identified as cost-effective and technically available for our system.

In the near-term, the risks of large, negative, long-term consequences for our compliance path relate to anything that delays or prevents our ability to execute on the Action Plan. The risks are real, given supply-chain and labor market challenges that, while improving, still exist as discussed in **Section 3.3, Market, labor and supplier dynamics**. Procurement delays, supply chain constraints, increased uncertainties in available transmission inventory, siting challenges and operational risks associated with adding large quantities of resources in a short period of time can delay our timeline. Any significant change in statutes, rules or guidelines that would require PGE to alter its strategy or restrict optionality in our pursuit of non-emitting resources, could also delay emissions reduction, or threaten reliability and affordability for customers. While demand response, energy efficiency and community-based renewable resources can offset some of the need for new resources, they cannot offset the need for most or avoid the need for new transmission options. These resources are an essential element of a successful outcome, but achieving their technical potential also depends on customer and community interest and participation. In the case of energy efficiency, under the current regulatory paradigm, it currently falls primarily to the ETO to deliver all the cost-effective energy efficiency potential in our service territory. Finally, our success also hinges on our ability to continue strengthening relationships and trust with stakeholders and communities. We will continue to look to stakeholders and communities for feedback on our efforts and be ready to adapt our strategies accordingly.

There will be critical junctures on our path to 2030, 2035 and 2040 emissions targets that may require material changes in our decarbonization pathways. Between now and 2030, PGE will be tracking closely the pace of acquisition of non-emitting energy and capacity. If we cannot maintain reliability or the pace of constant yearly acquisition of resources and capacity, we will need to adjust our approach to overcome delays or adjust timelines accordingly, if the variables causing the delay are beyond our control. At the same time, if new transmission options on- and off-system do not materialize, we will likely not be able to access the diverse resources our system needs to decarbonize and maintain reliability. Transmission is a challenge to both PGE and the region. Successful transmission solutions depend on regional coordination and cooperation, as well as on federal, state or local support for siting transmission resources.

To execute on our long-term plan beyond 2030, we need to see the quantities of non-emitting resources available on the market, and at the lower price points we forecasted for them. New transmission is needed to gain access to off-system resources or we risk the reliability of the system. As we near the 2040 target and an absolute zero emissions requirement, new technologies that can replicate thermal generation dispatchable capacity,

such as advanced nuclear, hydrogen or carbon capture and storage will be needed across the region to support decarbonization and resource adequacy.

The critical barriers that need to be addressed to implement PGE's long-term plan are likely similar to those of other utilities across the West who are rapidly decarbonizing. The major barriers are transmission and the need to rapidly develop and scale new non-emitting technologies. Solutions will depend on regional cooperation, coordination and federal policy and financial support; PGE's actions to expand partnerships regionally and continuously innovate new technologies are key near-term strategies toward successful, long-term pathways. To the extent that the Commission can support PGE's participation in these efforts, for example, in our pursuit of federal grant dollars or our participation in expanded regional markets like EDAM, the Commission can play an important role in mitigating barriers.

Over the next 5-10 years, our success will also depend on the Commission, as well as the Federal Energy Regulatory Commission (FERC) and other federal, state, and local regulatory bodies, adapting regulatory processes and mechanisms to meet new needs associated with the rapid transition and new operational reality of a renewables-dominated system. We will need the Commission's support to pursue transmission solutions and alleviate interconnection challenges. We will seek the Commission's support for our expanded deployment of dispatchable resources through our VPP efforts, as well as the development of new customer programs to grow our flexible loads and help customers manage costs. We may ask the Commission to consider changes to current regulatory constructs, such as PCAM (discussed in **Section 3.1.8, Regulatory policy: Power cost adjustment mechanism (PCAM)**) to reflect the reality of operating a system that is soon to be dominated by variable resources or competitive bidding rules. Customer programs and pricing structures designed when clean energy was the exception, rather than the norm, will need to be adjusted to equitably distribute costs and enable us to integrate more of these resources as a core component of our decarbonization strategy.

Chapter 2. Accessing support for energy transition

Portland General Electric's (PGE's) resource and decarbonization planning is occurring against the backdrop of a global transformation from fossil fuels to non-emitting energy resources and storage in the power sector. Technological advancement and public policy are key drivers of this energy transition, with implications for the cost and pace of increased penetration of non-emitting energy resources in the energy supply mix and the rapid onset of electrification and energy storage. To manage costs and enhance reliability for customers during this highly dynamic period of evolution in the energy sector, PGE is actively seeking federal and state incentives and other opportunities. We are also working with organizations across the energy sector to access the latest research and coordinating with state agencies, community-based organizations, utilities, businesses and other actors in Oregon to deliver federal support for Oregon's energy transition. This chapter describes those efforts and the implications for PGE's resource and decarbonization planning.

Chapter highlights

- Federal and state policies are helping to drive rapid decarbonization in ways that impact PGE's resource planning.
- Federal legislation such as the Inflation Reduction Act (IRA) and Infrastructure Investment and Jobs Act (IIJA) that expanded and extended tax credits will facilitate PGE's acquisition of new resources and help manage customer rate impacts.
- We are working across the energy sector to stay abreast of rapid technological and market changes so that customers benefit from the rapid changes occurring across the energy ecosystem.

2.1 Federal support for energy transition

The 117th Congress delivered a comprehensive federal policy response to climate change and an investment package to support broad clean energy, climate and infrastructure investments. This includes enacting programs and funding that would support renewable energy development, clean transportation, energy efficiency, the resiliency of power infrastructure and clean energy research. The passage of the IRA and the IIJA has significant potential impacts on PGE's resource and decarbonization planning with potential benefits for customers.

In **Section 8.1.6, Treatment of tax credits**, we discuss how our Integrated Resource Plan (IRP) analysis incorporates incentives from the IRA and IIJA. At the time of writing this Clean Energy Plan (CEP) and IRP, not every potential channel or program for accessing this transition package is known; billions of dollars in funding from the IRA and IIJA are still making their way to state and local governments, and funding opportunities are still being announced. As these dollars can potentially reduce the costs of the energy transition for customers and render the communities we serve more equitable and resilient, PGE will actively pursue these and other state or local opportunities, often in collaboration with other organizations. PGE has already been successful winning federal Connected Communities funding for our Smart Grid Test Bed.

The implications of new funding opportunities and incentives for our resource and decarbonization strategies are potentially significant and likely include the following:

- Lower costs and accelerated buildout of renewables and stand-alone energy storage due to production and investment tax credits.
- Additional deployment of energy efficiency and demand response.
- Expansion of micro-grid and other resiliency investments.
- Accelerated electrification because of consumer incentives for electric vehicles, heat pumps and building retrofits.
- Faster development of emerging non-emitting, dispatchable technologies that could bring them into planning horizons earlier than currently anticipated.

2.1.1 Inflation Reduction Act

With the passage of the Federal IRA of 2022, Congress enacted extensions, expansions, modifications of clean energy tax provisions and provided funding and incentives to support

decarbonization, energy efficiency and electrification.[18] This significant legislation has substantial implications for PGE, customers and climate and clean energy policy implementation.

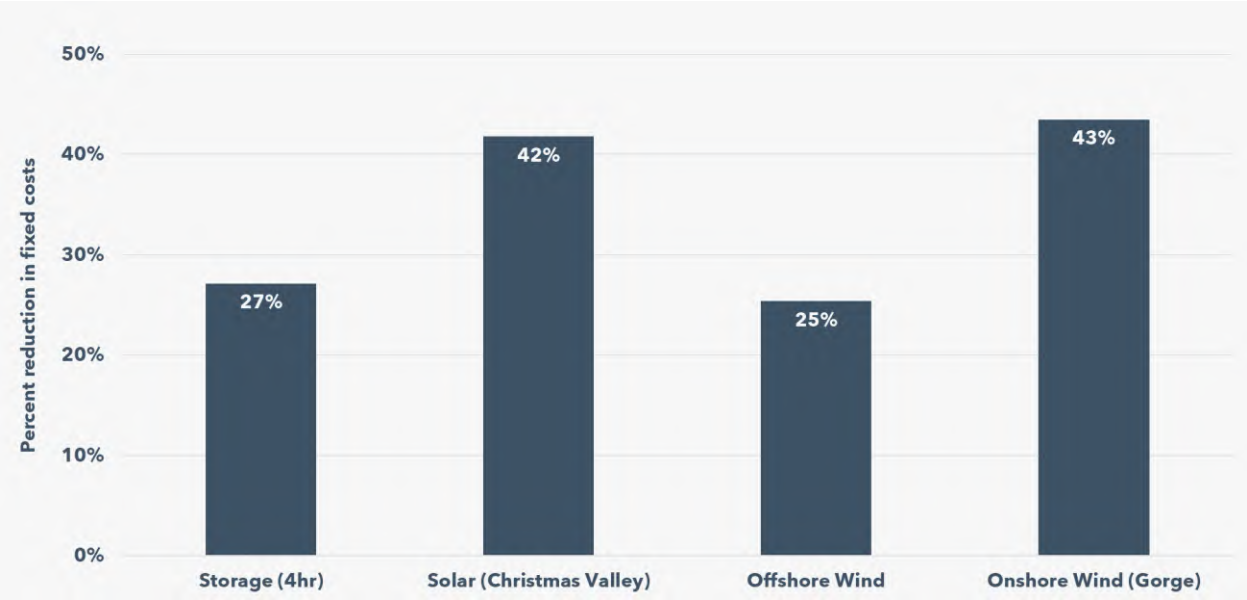
Clean energy tax credits most directly affect PGE's decarbonization and resource strategy. Traditional Investment Credits and Production Tax Credits (ITCs and PTCs) for specific resources, such as wind and solar, were extended to apply to projects that begin construction from January 1, 2022 (retroactively) to December 31, 2024. A new credit for standalone energy storage began on January 1, 2023. On January 1, 2025, the credits transition to technology-neutral tax credits tied to emission reductions provided by the qualifying resource as determined by future Treasury Department guidance. Credit availability would phase out when the later of these two conditions is met: 1) when the US power sector emits 75 percent less carbon than 2022 levels or 2) December 31, 2032.

The ITCs and PTCs available for clean energy projects have been restored to full rates, eliminating previously planned phase-outs.[19] However, eligibility for the full credit applies only if prevailing wage and apprenticeship requirements are met. Specifically, facilities must pay prevailing wages during construction and the first 10 years of operation. Using apprentices as a percentage of labor hours increases over time (10-15 percent of total labor). Exceptions to the apprenticeship requirement are possible for good faith efforts to hire apprentices. Additional adders are provided for meeting other criteria. These include a 10 percent increased credit for meeting domestic content requirements, a 10 percent increased credit for projects placed on or near a coal plant, referred to as Energy Community, that was retired after December 31, 2009; a 10 percent increased energy credit for solar and wind facilities with a net output of less than 5 megawatts (MW) placed in service in low-income communities or on tribal land; and a 20 percent increased credit for property that is part of a qualifying low-income residential building project or low-income economic benefit project. The 50 percent credit rate reduction for qualified hydroelectric production for property placed in service after December 31, 2022, is also eliminated.

The ITC and PTCs, after being restored to the full rates and taking advantage of the additional adders, can significantly reduce the costs of generating renewable energy. The estimated cost reductions for select sources of generation are seen in **Figure 14**. The IRP modeling assumes incremental resources are eligible for the 100 percent level of applicable tax credits.

[18] Inflation Reduction Act of 2022, Pub. L. 117-169, Aug. 16, 2022, 136 Stat.1818.
[19] Modeling in this IRP assumes all requirements met by incremental resources to maximize tax potential. For additional information on the requirements associated with tax credits, please see the Inflation Reduction Act of 2022, available at: https://www.congress.gov/bill/117th-congress/house-bill/5376

Figure 14. Estimated cost reduction from IRA for select generation sources



The IRA attempted to resolve an important clean energy tax disadvantage that impacts resource costs for utility customers. The ITC is subject to tax normalization rules, which require public utilities to recognize the benefits from the ITC over the life of the resource, while non-utilities can recognize the benefits of the ITC in year one. The IRA provides alternatives to the ITC by providing a solar PTC and an opt-out from normalization rules for the new standalone storage ITC. However, the IRA was written, whether intentionally or not, so that the clean energy tax credit adders are not applied equally to the ITCs and PTCs. For example, the ITC, with one adder, goes from 30 percent to 40 percent of capital costs, which is a 33 percent increase in the credits value, while the PTC rate for generation only increases by 10 percent. This disproportionate increase will make the ITC with adders more valuable than a similar PTC with adders. Therefore, the normalization issue will likely persist only for solar projects, given its lower annual output compared to wind. PGE will continue exploring different options to work around the normalization issue, such as a wholly owned regulated affiliate, to promote greater competition in future resource solicitations to deliver the least cost resources for customers.

Overall, the clean energy provisions of this new legislation are expected to affect PGE's acquisition of new resources by helping keep customer rates lower through expanded and extended credits. Additionally, the IRA creates the concept of credit transferability. This allows for the sale of PTCs and ITCs generated by either new or existing facilities after December 31, 2022. PGE currently has a surplus of tax credits, resulting in a carryforward balance included in the rate base. However, with transferability, PGE will be able to monetize the value of the credits much more efficiently and eliminate the carryforward balance more quickly. This ultimately leads to lower costs for customers.

Other provisions in the law will support the expansion of transmission, help advance permitting, provide grants to support projects and support energy efficiency and transportation electrification. For example, the Building A Better Grid Initiative (BABGI)[20] incentivizes the development of new and upgraded transmission infrastructure. Key BABGI elements include:

- $2.5 billion Transmission Facilitation Program intended to support the development of nationally significant transmission lines, increase inter-regional connectivity and create access to renewables.
- $2.3 billion in Grid Innovation grants to states, territories and tribes to strengthen and modernize the country's grid. (PGE is working with the Confederated Tribes of Warm Springs in an effort to develop a qualifying project).
- $10.5 billion Grid Resilience and Innovation Partnership Program, which includes funding for projects that improve the grid's resilience, enhance grid flexibility and support the development of transmission and distribution (T&D) infrastructure.
- $760 million dollar Transmission Siting and Economic Development Grants program.

Also included are clean vehicle provisions, energy efficient credits and residential clean energy credits.

The IRA eliminates the previous 200,000-vehicle manufacturer cap on the clean vehicle tax credit, which means Tesla, GM and Toyota EVs will be eligible again. The Electric Vehicle (EV) credit will now be available for both new (credit up to $7,500) and used (credit is the lessor of $4,000 or 30 percent of sales price) vehicles. The credit does require vehicles to undergo final assembly in North America, which has limited the vehicles that currently qualify for credits. In addition, credits after December 31, 2023, and December 31, 2024, are increasingly tied to where minerals and batteries, respectively, are sourced, favoring materials from free trade partners. The electric vehicle (EV) and alternative fuel charging

[20] More information on the 'Building a better grid' initiative, available at: https://www.energy.gov/gdo/building-better-grid-initiative

credits are extended through 2032. Despite new limitations to some provisions, it is expected that these tax credits, along with others supporting transportation electrification, such as US Environmental Protection Agency (EPA) grants and commercial and manufacturing credits, will drive additional adoption of EVs and support transportation electrification. PGE's long-term load forecast will increase as a result. In this IRP, we consider a broad range of load growth scenarios to account for the potential impacts of factors that may accelerate electrification. This is further described in **Section 4.2, Need Futures**. Furthermore, PGE has also assessed how energy and capacity needs would change if the load grew faster than the high case. This is further described in **Section 6.10.2, Accelerated load growth sensitivity**.

The Residential Energy Efficient Home Improvement credit is restored through 2032 and promotes energy efficiency investments in homes. Residential clean energy credits of 30 percent are extended in full through 2032, with a phase-out through 2034. Residential customers will be able to apply this credit to solar installations and standalone energy storage systems.

One additional goal of the IRA is to strengthen domestic manufacturing. This aim is reflected in the varying domestic content requirements for credits, as previously noted, for example, in the clean energy and clean vehicle tax credits. The domestic supply chain ecosystem will take time to develop, and the expectation is that there will continue to be supply chain issues in the short-term planning horizon.

2.1.2 Infrastructure Investment and Jobs Act

The IIJA was signed into law on November 15, 2021. The IIJA directs $1.2 trillion of spending to infrastructure, defined very broadly. This includes traditional infrastructure funding focused on roads and bridges, public transit systems, passenger rail, ports and airports, as well as investments in the electric grid, broadband infrastructure, water systems, cybersecurity, transportation electrification and climate resilience. It will spur a historic investment in energy. Most notably among its many programs, the bill funds $23 billion to enhance the resiliency of the power infrastructure and investment in renewable energy, $21.5 billion to develop clean energy demonstrations and research hubs, $9 billion to enhance manufacturing facilities and projects, and $5 billion to boost energy efficiency and clean energy creation. It also has over $18 billion in support of EV charging deployment, clean transit and school buses, and other transportation electrification funding.

PGE is pursuing – and plans to pursue – grant opportunities for infrastructure projects that can benefit customers and lower customer rate impacts. Currently, PGE is currently following the grant submission process for over $500M of potential award, on just over $900M of total project cost. The overall status of grants that PGE is pursuing through IIJA is shown in **Figure 15**, which is current as of March 2023:

Figure 15. IIJA grant submission and funding progress

Grant Potential	$12M	$0M	$400M+	$79.4M	$6M	Grant total potential: $497M+
Project Cost	$26M +	$0M	$800M+	$145M	$12M	Project total potential: $982M+

The funding opportunities sought by PGE align with the need for decarbonized energy supply, reliable service and more flexible processes and systems to meet customer needs. PGE's funding opportunities seek to meet those objectives as follows:

Grid resiliency improvement projects: These projects will accelerate the modernization of our T&D grid with the implementation of a variety of technologies. These technologies include distribution automation and early fault detection, along with hardening techniques such as undergrounding of high voltage lines and the installation of covered conductors where appropriate within PGE's High Fire Risk Zones (HFRZs).[21] We will also seek funding to upgrade existing lines to allow for the import of additional carbon-free generation to meet PGE's clean energy targets.

Middle mile fiber: The focus area will prioritize broadband communications and grid resiliency by providing broadband services to underserved communities along existing transmission paths. Fiber optic communications cables also will provide increased resiliency and communication options for PGE and customers.

Grid services demonstration: This demonstration will highlight the ways in which technologies at an existing PGE renewable energy facility can provide different types of active and reactive power controls to transform a renewable resource from a simple intermittent energy source to a resource capable of providing a wide range of grid services.

Hydropower initiatives: Hydropower facility grants will allow for upgrades and improvements that target resiliency, dam safety and environmental projects at multiple facilities that meet the requirements of the funding opportunity announcement. PGE continues to invest in hydropower as a carbon-free source of dispatchable capacity.

[21] HFRZs are areas within PGE's service territory where vegetation, terrain, meteorological patterns and wildland-urban interface considerations increase the risks associated with wildfire. PGE implements specific inspection and maintenance, vegetation management and operational actions within these HFRZs during and in preparation for PGE's declared Fire Season for improved ignition prevention and safety.

Table 4. Active PGE project applications

Grant Vehicle	Focus area	Projects	Grant Funding
IIJA Grid Resilience and Innovation Partnerships (GRIP)	Topic area 1 / Grid resilience	1	$100M
	Topic area 2 /Grid flexibility	2	$50+M
	Topic area 3 / Transmission innovative partnerships	1	$250M
National Telecommunication and Information Administration (NTIA)/IIJA	Middle Mile	1	$29M
IIJA	Grid services demonstration	1	$6M
IIJA	HydroWIRES technical assistance	1	TBD
IIJA	Hydropower incentives	4	$13M

2.2 State support for energy transition

Federal funding for the clean energy transition will be made available through different programs and channels, including those available to state agencies, utilities, businesses, community-based organizations, Tribes and local governments. PGE is committed to working with entities across Oregon to help deliver federal funding for the energy transition. While not all the previously-referenced federal funding for transition will flow through state agencies, the Oregon Department of Energy (ODOE) and Oregon Department of Transportation (ODOT) will be important conduits for customers to access these new opportunities.

With the new federal funding available, DOE has received and is seeking additional funding for the State Energy Program to support energy efficiency, resilience and sustainable transportation.[22] In addition, DOE is seeking funding for grid resilience, building codes and electrification, and energy efficiency programs, including an energy efficiency revolving loan fund. DOE is also supporting the energy transition under the direction of House Bill (HB) 2021. DOE was required to convene stakeholders to conduct a Small-Scale Renewable Energy Projects study.[23] HB 2021 also created a $50 million fund to provide grants for planning and developing community renewable energy and energy resiliency projects. While the grant program is not open to investor-owned utilities like PGE, it is available for Tribes and local governments in our service territory.

ODOT will receive $52 million in federal funds through the IIJA's National Electric Vehicle Formula Program over five years.[24] That program provides funding to states to build electric vehicle (EV) charging infrastructure and facilitate EV charging data collection, access and reliability. ODOT plans to work with a broad range of stakeholders and partners, including PGE, to apply funding toward building out passenger vehicle corridors, future-proofing corridors for future heavy-duty freight charging, and filling public EV charging gaps for medium- and heavy-duty vehicles, BIPOC and rural communities. Combined with other state policies helping to accelerate vehicle electrification, this additional funding can help accelerate the growth of new flexible loads in our service territory.

2.3 Technology and market research

Decarbonizing reliably and affordably for customers means staying abreast of the latest clean energy technology and market research across the globe. The energy landscape is rapidly evolving. To deploy customer dollars prudently in proven technologies, PGE works with other organizations to gain access to cutting edge data and information and to pool research dollars and best practices. For example, we are actively working with the Energy Power Research Institute (EPRI) on issues ranging from climate adaptation, wildfire protection, safety and transmission planning to new non-emitting technologies of the future, like carbon capture and storage, hydrogen and others. We participate in consortiums with utilities and energy companies that invest in early-stage new technologies to mitigate risks while learning first-hand how those technologies are evolving. Our CEO, Maria Pope, serves on the Secretary of Energy Advisory Board, and as part of the smart grid working group, PGE has

[22] Information about the State Energy Program is available at: https://www.energy.gov/scep/about-state-energy-program
[23] Information about the Small-Scale Renewable Energy Projects Study is available at: https://www.oregon.gov/energy/Data-and-Reports/Pages/SSREP-Study.aspx
[24] Information about the National Electric Vehicle Formula Program is available at: https://www.transportation.gov/bipartisan-infrastructure-law/regulations/2022-12704

prepared whitepapers for the ODOE on the virtual power plant (VPP) and transmission planning for distributed energy resources (DERs).

These relationships and others help us deliver the benefits of rapid technological change across the global energy ecosystem to customers in Oregon. They have helped us to lower our operating costs, minimize disruptions and transform how we integrate wind, solar and battery technologies. For example, our Wheatridge facility was the first of its scale to combine all three technologies to better utilize existing significant and scarce transmission resources and to serve customers with non-emitting power. As we look to the future and lowering emissions to meet our targets, these relationships and access to federal and state support for energy transition will help us manage costs for customers and provide exceptional products and services.

Chapter 3. Planning environment

Long-term planning occurs in the context of evolving law and policy, technological advances, economic conditions, advancing scientific understanding of the effects of climate change, and general environmental concerns. Each of these factors impact resource economics, customer prices, community benefits and the resource decisions Portland General Electric (PGE) makes in the best interests of its customers. This chapter explores the broader planning context influencing our overall resource strategy to reliably and affordably meet customers' energy needs while achieving emissions reduction and other regulatory requirements.

Chapter highlights

- Federal and state policy impacts the planning environment for PGE's Integrated Resource Plan (IRP) and Clean Energy Plan (CEP).
- Regulatory policy may need to adapt to changing dynamics created by state and regional decarbonization objectives.
- Thermal resource retirement in Oregon and the West creates challenges for resource adequacy as the region decarbonizes.
- Continued uncertainty related to labor markets, supply chains and the macroeconomy presents challenges to decarbonization efforts.

3.1 Federal and state law and regulatory policy

Since PGE's last IRP was acknowledged with conditions and directives on March 16, 2020, federal and state policies related to clean energy and greenhouse gas emissions have evolved significantly. As discussed in **Chapter 2, Accessing support for energy transition**, the federal government recently advanced transformative comprehensive climate policy with the passage of the Inflation Reduction Act (IRA) and the Infrastructure Investment and Jobs Act (IIJA). It also passed the CHIPS and Science Act, which has direct implications for our service territory. At the state level, new executive orders, state agency rules and legislation related to electric sector greenhouse gas emissions, energy efficiency, transportation electrification and building decarbonization impact the planning environment for this IRP.[25]

[25] 2021: HB 2021, HB 2475, HB 2482, HB 2027, HB 2165 and HB 3141; 2022: HB 5202, SB 1536 and SB 1518.

3.1.1 CHIPS and Science Act

Congress recently passed the CHIPS and Science Act of 2022 (H.R. 4346).[26] This legislation is designed to boost US competitiveness and innovation. It is expected to support future scientific research and development funding that could help clean energy advancement through future appropriations the Act authorizes. It also provides funding to support domestic semiconductor chip manufacturing, which may help address supply chain issues as chips are so prevalent throughout goods, and their shortage has impacted supply chains. The CHIPS Act directs $280 billion in spending over the next 10 years. The spending is allocated to scientific research and development (R&D) and commercialization ($200 billion authorization), semiconductor manufacturing, R&D, and workforce development ($53 billion), tax credits for chip production ($24 billion), and programs aimed at leading-edge technology and wireless supply chains ($3 billion). As a result of the CHIPS Act, Oregon Business Council and ECONorthwest research estimate Oregon could see upwards of $40 billion of investment over the next 10 years, with tens of thousands of jobs and $2-3 billion in local tax revenue. Service territory semiconductor investments will directly impact PGE's load growth.

In this IRP, we consider a broad range of load growth scenarios to account for potential impacts. This is further described in **Section 4.2, Need Futures**. Furthermore, PGE has also assessed how energy and capacity needs would change if the load grew faster than the high case. This is further described in **Section 6.10.2, Accelerated load growth sensitivity**.

3.1.2 Oregon House Bill 2021

In the 2021 Legislative Session, the Oregon Legislature enacted House Bill (HB) 2021.[27] This bill requires PGE to reduce the greenhouse gas emissions associated with electricity sold to retail electricity consumers in Oregon. Specifically, the bill requires utilities to reduce those emissions by at least 80 percent below a 2010-2012 average baseline level of emissions by 2030, by at least 90 percent below baseline emissions levels by 2035; and to 100 percent below baseline emission levels by 2040.[28] Program implementation is shared between the Public Utility Commission of Oregon (OPUC or the Commission) and the Oregon Department of Environmental Quality (ODEQ). ODEQ's primary responsibility is collecting greenhouse gas emissions data, determining baseline emissions, calculating the reductions necessary to meet the targets and verifying projected emissions reductions. ODEQ's determination and

[26] The Creating Helpful Incentives to Produce Semiconductors and Science Act of 2022 (CHIPS Act) was signed into law on August 9, 2022.
[27] ORS 469A.400 469A.475, amended by OR Laws 2021, Chapter 508, available at: https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2021/Enrolled
[28] ORS 469A.400 469A.475, amended by OR Laws 2021, Chapter 508, Section 3, available at: https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2021/Enrolled

verification is based on emissions data reports submitted by the electricity providers under OAR-340-215-0120 to Oregon's Greenhouse Gas Reporting Program.[29] The Commission must ensure that utilities demonstrate continual progress toward the greenhouse gas targets.[30] Utilities must develop a CEP to meet the targets concurrent with each IRP development and convene a Community Benefits and Impacts Advisory Group (CBIAG) to solicit feedback from environmental justice (EJ) communities and low-income customers. This combined filing of PGE's CEP and IRP complies with HB 2021's requirements and related guidelines adopted by OPUC.[31]

PGE will continue to submit annual reports to ODEQ as it does now. As of 2021, ODEQ has required third-party verification of PGE's annual emissions reporting. PGE received a positive verification statement by the deadline of September 30, 2022, for the 2021 annual ODEQ Investor-Owned Utility emissions reporting. In the compliance years 2030, 2035, 2040 and every year thereafter, the OPUC will use the greenhouse gas emissions data reported to ODEQ for that compliance year to determine whether the emissions targets are met. This program is based on the actual emissions associated with the power served to retail customers and does not use renewable energy certificates (RECs) to track compliance.[32] The bill contains a reliability pause and a cost cap to ensure the targets are reached affordably and reliably.[33,34]

HB 2021 also includes a range of clean energy provisions not directly related to the Greenhouse Gases (GHG) targets at the heart of the bill. These include:

- **Allows community-wide clean energy tariff:** Sets forth the process for developing and approving a community-wide green energy tariff. PGE is actively engaged with the cities we serve to develop such a program.[35]
- **Bars new emitting facility site certificates:** Prohibits the Energy Facility Siting Council (EFSC) from issuing a site certificate for a new generating facility that produces electric power from fossil fuels unless the new generating facility will generate only non-GHG-

[29] Information about Oregon's Greenhouse Gas Reporting Program is available at: https://www.oregon.gov/deq/ghgp/Pages/GHG.aspx
[30] ORS 469A.400 469A.475, amended by OR Laws 2021, Chapter 508, Section 4(6), available at: https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2021/Enrolled
[31] *In the Matter of Public Utility Commission of Oregon, House Bill 2021 Investigation into Clean Energy Plans*, Docket No. UM 2225, the OPUC adopted CEP expectations in Order Nos. 22-206 (Jun 3, 2022), 22-390 (Oct 25, 2022) and 22-446 (Nov 14, 2022).
[32] ORS 469A.400 469A.475, amended by OR Laws 2021, Chapter 508, Sections 1-3, available at: https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2021/Enrolled
[33] ORS 469A.400 469A.475, amended by OR Laws 2021, Chapter 508, Section 9, available at: https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2021/Enrolled
[34] ORS 469A.400 469A.475, amended by OR Laws 2021, Chapter 508, Section 10, available at: https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2021/Enrolled
[35] ORS 469A.400 469A.475, amended by OR Laws 2021, Chapter 508, Section 20, available at: https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2021/Enrolled

emitting electricity. Further prohibits EFSC from approving a site certificate amendment for an energy facility powered by fossil fuels in a manner that would "significantly increase the gross carbon dioxide emissions that are reasonably likely to result from the operation of the energy facility."[36]

- **Small-scale Renewables Requirement:** Increases the existing small-scale renewable mandate in the Oregon Renewable Portfolio Standard from an 8 percent capacity standard to a 10 percent capacity standard.[37]
- **Community Renewable Energy Grant Program:** Creates a $50 million fund at the ODOE to provide grants for planning and developing community renewable energy and energy resilience projects.[38]

3.1.3 Oregon Climate Protection Program (CPP)

Oregon Governor Kate Brown issued Executive Order 20-04 in March 2020, directing state agencies to adopt policies and programs as allowable under existing law to help the state meet statewide emissions targets. In response, the ODEQ established the CPP, a new regulatory program that began in 2022 aiming to dramatically reduce greenhouse gas emissions in Oregon over the next three decades. The CPP sets a declining limit, or cap, on greenhouse gas emissions from fossil fuels used throughout Oregon, including diesel, gasoline, natural gas and propane, used in transportation, residential, commercial and industrial settings. The program also regulates site-specific greenhouse gas emissions at manufacturing facilities, such as emissions from industrial processes, with a best available emissions reduction approach. The CPP does not apply to Oregon's electric utilities, energy service suppliers or electricity-generating facilities.

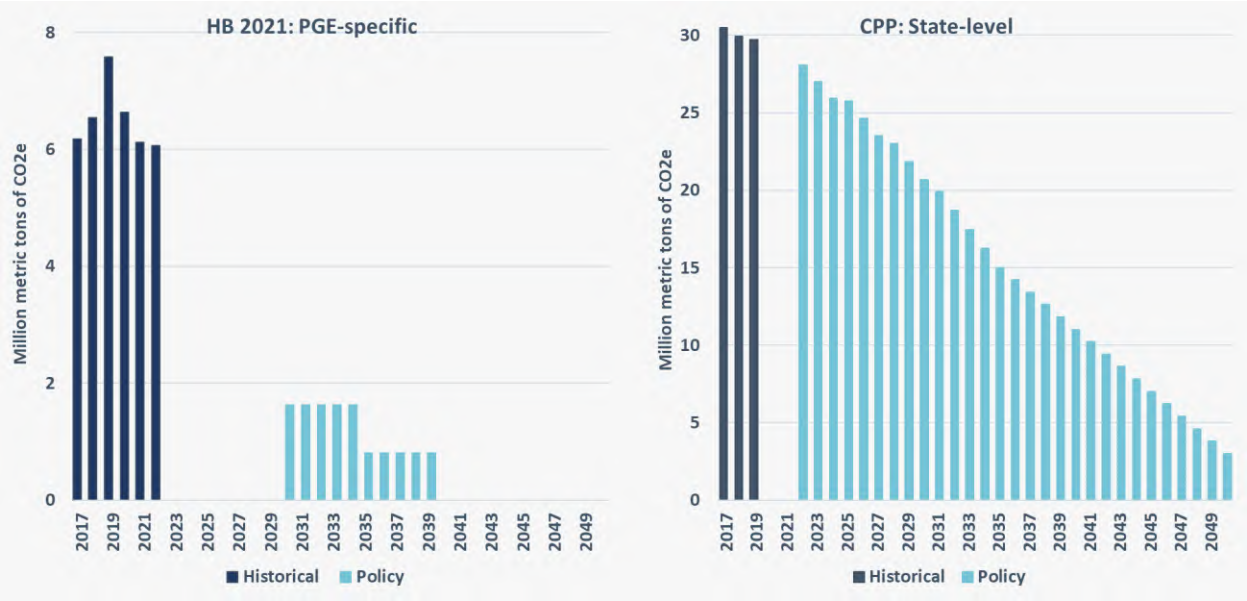
In 2022, PGE contracted with Evolved Energy Research (EER) to undertake an independent analysis exploring pathways to deep decarbonization across all energy sectors in its service area. ("Deep Decarb Study Update").[39] This study updated an earlier Deep Decarb Study in

[36] ORS 469A.400 469A.475, amended by OR Laws 2021, Chapter 508, Section 28, available at: https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2021/Enrolled
[37] ORS 469A.400 469A.475, amended by OR Laws 2021, Chapter 508, Section 37, available at: https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2021/Enrolled
[38] ORS 469A.400 469A.475, amended by OR Laws 2021, Chapter 508, Section 29, available at: https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2021/Enrolled
[39] Evolved Energy Research. (2022, August 15). Deep Decarb Study Update Technical Report. Portland General Electric Resource Planning. Retrieved February 14, 2023, available at: https://assets.ctfassets.net/416ywc1laqmd/3KDEMrOpMkbjduyiBeen3z/88464626dbcd98c97f669289cb0dbd7d/EER_PGE_Deep_Decarb_Study_Update_Memo_.pdf

2017 by EER to include Oregon's recent adoption of HB 2021 and ODEQ's CPP.[40] The study found that while the CPP does not directly regulate the electric sector, end-use electrification is likely to be a key CPP compliance strategy in transportation and building sectors. Electrification will increase PGE's total load (and corresponding resource requirements to meet HB 2021), but it will also create the opportunity to leverage flexibility from newly electrified loads like smart electric vehicle charging and water heating. As noted earlier, in **Section 4.2, Need Futures**, and **Section 6.10.2, Accelerated load growth sensitivity**, we consider a broad range of load growth scenarios to account for potential impacts of federal and state policy drivers of electrification.

A comparison of the emissions reduction goals of HB 2021 and the CPP is given in **Figure 16**.[41]

Figure 16. Emission reduction goals HB 2021 and CPP



[40] Evolved Energy Research. (2018, April 24). Exploring Pathways to Deep Decarbonization for the Portland General Electric Service Territory. Portland General Electric Resource Planning. Retrieved February 14, 2023, available at: https://assets.ctfassets.net/416ywc1laqmd/7tc4cXtpYgEOTM8my6rxsP/987f9f746e1bae5072204693a34c1b68/exploring-pathways-to-deep-decarbonization-PGE-service-territory__1_.pdf

[41] PGE Deep Decarb Study available at: https://assets.ctfassets.net/416ywc1laqmd/7zH0gqWpupl16cMDeEGme5/46b024e14df63f3256a428c982f9708e/PGE_Deep_Decarb_Study.pdf

3.1.4 Transportation electrification

The 2021 Legislature enacted House Bill (HB) 2165 to extend and improve Oregon's electric vehicle (EV) rebate and support utility investment in electric vehicle infrastructure.[42] House Bill 2165 removes the 2024 sunset on Oregon's EV Rebate program and makes other targeted changes to support underserved communities better. House Bill 2165 also requires PGE and Pacific Power to collect a charge set to 0.25 percent of the total revenues collected by the utility, at least half of which is to be spent on TE in underserved communities. The bill updates ORS 757.357 to clarify OPUC authority to allow utility cost recovery for TE infrastructure measures and recognizes that utility investment to support TE includes behind-the-meter infrastructure.

Oregon's state agencies are also working to advance TE in response to Governor Brown's Executive Order 20-04. In March 2021, the Oregon Environmental Quality Commission (OEQC) adopted revised Clean Fuels Program rules to increase the amount of clean fuels credits generated from EV charging, and the EQC has extended the Clean Fuels Program another 10 years to 2035. The EQC also adopted California's Advance Clean Trucks rule that requires manufacturers of medium- and heavy-duty vehicles to sell a certain percentage of zero-emission vehicles and has adopted a similar standard for light-duty vehicles through the Advance Clean Cars II rule.

The Oregon Department of Transportation (ODOT) is working to implement the federal 2021 Infrastructure Investment and Jobs Act, which provides formula funds and flexible funds that ODOT plans to use to deploy EV charging across the state. The Department has announced more than $100 million in combined state and federal funding for transportation electrification over the next five years.

These state efforts to support, fund and accelerate TE are expected to complement PGE's utility- and Clean Fuels-funded programs. These policies are also expected to drive load growth from TE, as reflected in PGE's load forecast. As noted earlier, in this IRP, we consider a broad range of load growth scenarios to account for potential impacts of federal and state policy drivers of electrification in **Section 4.2, Need Futures**, and **Section 6.10.2, Accelerated load growth sensitivity**.

[42] HB 2165 (2021), available at: https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2165

3.1.5 Energy efficiency and building decarbonization

Energy efficiency is an important resource for PGE to meet its decarbonization targets and helps customers save money in the process. House Bill (HB) 3141 was enacted in the 2021 session to enable the continuity of energy efficiency programs for PGE customers by modernizing and extending the Public Purpose Charge beyond its scheduled expiration. [43,44] The bill extends the Public Purpose Charge to 2035 from its current expiration in 2025. It removes energy efficiency funding from the Public Purpose Charge, moves it into rates, increases funding for low-income weatherization and modifies the existing renewables provision to include storage and grid optimization investments that enhance resilience, reliability and renewable power integration.

At present, multiple bodies receive and disburse funding for energy efficiency investments in Oregon, including the Oregon Health Authority (OHA), Oregon Housing and Community Services (OHCS), ODOE and Energy Trust of Oregon (ETO). OHA administers the Healthy Homes Program established in the 2021 Legislative session via House Bill (HB) 2842.[45] The program provides funds to assist low-income households in repairing and rehabilitating their residences. The funds can be used to maximize energy efficiency and make improvements to make a home more fire-resistant or seismically resilient, among other health and safety measures. OHCS administers the Low-Income Home Energy Assistance Program (LIHEAP), Low Income Weatherization Assistance Program (WAP) and the Multifamily Energy Program, and Weatherization Training and Technical Assistance (WX T&TA). ODOE administers the Heat Pump Incentive Program established by Senate Bill (SB) 1536 (2022), Energy Efficient Wildfire Rebuilding Incentive established by House Bill (HB) 5006 and the Energy Efficient Schools Program and works to shape codes and standards for the built environment. [46,47]

In the 2022 Legislative Session, the Legislature enacted the Emergency Heat Relief Bill (SB 1536), including an allocation of $25 million to the ODOE to support the installation of heat pumps in the state through two distinct programs. The Heat Pump Deployment Program will support residential customers by providing grants directly to individuals to cover up to 100 percent of the cost of the purchase and installation of a heat pump. The grant funds can also be used to support related upgrades needed to support or enable the new heat pump,

[43] HB 3141 (2021), available at: https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB3141
[44] More information about the Public Purpose Charge, available at: https://www.oregonlegislature.gov/lpro/Publications/Public-Purpose-Charge-Background-Brief.pdf
[45] HB 2842 (2021), available at: https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2842/Enrolled
[46] SB 1536 (2022), available at: https://olis.oregonlegislature.gov/liz/2022R1/Downloads/MeasureDocument/SB1536/Enrolled
[47] HB 5006 (2021), available at: https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB5006/Enrolled

including new or upgraded electrical panels, weatherization and upgrades to improve the airflow of the home. The bill also establishes a residential heat pump program that will provide rebates to contractors for the "purchase and installation of air-source or ground-source heat pumps" for residential customers, not to exceed 60 percent of the purchase price. Since 2002, ETO has administered energy efficiency programs for industrial, commercial and residential sectors on behalf of, and in collaboration with, utility funders. PGE and ETO have realized conservation, on average, of greater than 30-megawatt average (MWa)/annually for the past 10 years and at a levelized cost of energy (LCOE) of less than $0.0375/kWh. In the 2021 Legislative Session, the Legislature enacted HB 3141 which maintained funding levels for OHCS low-income weatherization, low-income affordable housing and energy conservation in schools while tying energy efficiency funding to the cost-effective amount available as determined through planning.

House Bill 3141 required greater budgeting coordination between utilities and ETO. PGE and ETO are now identifying opportunities to leverage programmatic funding as well as other sources of funding to. Coordinated programmatic efforts between ETO and PGE can improve our collective efforts to manage deployment dollars and stack incentives and benefits of both energy efficiency and flex load to enhance grid reliability. In addition to enabling flexible resources that may be called upon to support decarbonization targets and address both equity and grid constraints via non-wires solutions, energy efficiency investments serve to enable beneficial electrification, which has the potential to foster beneficial load growth and stabilize rates.

Given that the 2022 Federal Inflation Reduction Act (IRA) will provide tax credits, incentives and loans for energy efficiency investment, we are also working closely with the ODOE as we collectively work to leverage activity to help those facing energy cost challenges to attract and deploy federal energy efficiency funding dollars.

3.1.6 Local climate action planning

Nine cities and counties served by PGE have already established climate-related goals through community processes and plans, and at least four more are in the process of developing plans. These plans typically cover a variety of goals and objectives, including those concerning greenhouse gases, energy use, transportation, waste, land use, health and safety, and economic development. **Table 5** captures a list of local governments with existing plans (or in some phase of developing one) and some key electricity and emissions goals.

Table 5. Local governments' climate action plans

Local government	Emissions Goals	Plan under development
Beaverton	Net zero emissions from electricity by 2035; 100% reduction of GHGs by 2050	
Clackamas County		X
Gresham		X
Hillsboro	General initiative to reduce carbon emissions	
Lake Oswego	Net zero emissions from electricity use in buildings by 2035; Carbon neutrality by 2050	
Milwaukie	Net zero emissions from electricity by 2030; Carbon neutrality by 2045	
Multnomah County	100% renewable electricity by 2035	
Portland	100% renewable electricity by 2030; 50% emissions reduction by 2030; carbon neutrality by 2050	
Salem	50% emissions reduction by 2035 and carbon neutrality by 2050	
Sandy	Carbon neutrality by 2050	
Silverton	100% carbon free electricity for City buildings	
Tigard		X
Tualatin		X
West Linn	50% reduction in buildings by 2040; 100% reduction in transportation by 2040	

Several cities and counties have timelines for their decarbonization goals that align with our HB 2021 targets. For those local governments that want to decarbonize on a faster timeline, PGE's Green Future Enterprise and Green Future Impact are being used to support clean energy goals. Many of our large commercial and industrial customers also use these and other programs to meet their decarbonization goals.

PGE has been working with local governments since 2020 to develop a community-supported renewable program to support those local governments that have adopted

community-wide climate goals. During the 2021 legislative session, PGE worked in partnership with several of our local governments to pass language within HB 2021. The program will allow local governments to work with PGE to accelerate the procurement of non-emitting energy to meet their climate goals. Since the bill's passage, PGE staff have been meeting regularly with local governments to solicit feedback on the design so that the program will meet their goals and desired approach. As PGE continues to engage with local governments, collectively we will determine the right time to file the tariff to support the program.

3.1.7 Regulatory policy: Direct access

Oregon Electricity Service Suppliers (ESSs) have their own clean energy targets as part of House Bill (HB) 2021 Section 3(1) and are responsible for decarbonizing the electricity sold to direct access customers. IRP guideline 9 does not allow PGE's resource planning to include customers that have elected to receive their power through direct access from an ESS, even though PGE retains the responsibility of Provider of Last Resort. To be eligible for direct access, nonresidential customers must have a facility capacity of at least 250 kW and an aggregate load of 1 MWa. This direct access option was initiated in 1999 with the passage of Senate Bill (SB) 1149, "[r]elating to restructuring of electric power industry." The legislature's goals, articulated in the preamble, took into "consider[ation] national trends toward electric deregulation" at the time.[48]

Senate Bill (SB) 1149 included the provisions for direct access, which was defined as "[…] the ability of a retail electricity consumer to purchase electricity and certain ancillary services, as determined by the commission for an electric company […], directly from an entity other than the distribution utility."[49] These are the entities known as ESSs. Much has changed since the passage of this deregulation law, particularly Oregon's greenhouse gas reduction goals to address climate change.

The design of the various direct access offerings has largely been left to the discretion of the Commission. PGE began offering a one-year direct access/market price option effective March 1, 2002, consistent with legislative provisions.[50,51] In the 2003 service period, PGE added the option for eligible customers to opt out of cost-of-service energy supply for a minimum of five years (long-term direct access) with a pre-specified transition adjustment

[48] Oregon Laws 1999, Chapter 865, available at: https://www.oregonlegislature.gov/bills_laws/lawsstatutes/1999orLaw0865.html
[49] *Id.*, at Section 1(6).
[50] *Id.*
[51] HB 3633 (2001), available at: https://www.oregonlegislature.gov/bills_laws/archivebills/2001_EHB3633.pdf

fee.[52] PGE's long-term direct access program has a cap of 300 MWa.[53] In 2020, PGE launched a new large load direct access option capped at 119 MWa, allowing customers with a "new load" (uncommitted to PGE and expected to grow to 10 MWa or more over three years) to avoid cost-of-service (PGE Schedule 689).[54] These direct access caps are essential to help mitigate the potential for cost shifting.

The Commission began an investigation into IRP requirements in 2002.[55] Five years later, the Commission adopted IRP Guideline 9 relating to the treatment of direct access loads: "[a]n electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier."[56] The Commission believed that long-term direct access customers are "[…] 'effectively committed to service' under direct access and should be excluded from the IRP load-resource balance over the planning horizon."[57] This has led to a situation where the Commission has limited insight into the extent that ESSs plan to serve their loads reliably, while electric utilities cannot plan for long-term direct access customers. As Commission Staff have observed, "IOUs don't plan for long-term opt-out customers, while ESSs generally have short-term contracts with the opt-out customers […] the mismatch between contract length, and resource lifecycles could lead to a situation where no entity is planning for the RA of long-term opt-out customers absent Commission intervention."[58] At the end of the September 2022 long-term direct access election window, approximately 11 percent of PGE's net system load had opted out of cost-of-service supply.

The Commission opened an investigation into long-term direct access in 2019, focusing on resource adequacy, the costs and benefits of direct access and lessons learned from other states.[59] At the beginning of 2021, a separate proceeding was opened to specifically investigate the topic of resource adequacy in Oregon (see **Chapter 4, Futures and**

[52] Transmission Access Service Schedules: 485 Large Nonresidential Cost of Service Opt-Out (201-4,000 kW); 489 Large Nonresidential Cost of Service Opt-Out (>4,000 kW); 490 *Sch 490 must aggregate to >30MWa. This change became effective May 9, 2022, with UE 394*. Large Nonresidential Cost of Service Opt-Out (> 4,000 kW and Aggregate to >100 MWa). These all have a Minimum Five-Year Option and a Fixed Three-Year Option.

[53] In ADV 02-17 when we filed the first Sch 483. It had been discussed in a workshop for AR 441 and parties discussed the 300MWa in a workshop but decided it shouldn't be in the rules but should be included in the rate schedule.

[54] See PGE Schedule 689, New Large Load Cost of Service Opt-Out (>10MWa), available at: https://assets.ctfassets.net/416ywc1laqmd/1Cpia6NCTgU4OMLbqcru7J/52d5f28218bf70eb66366a9d677f682f/Sched_689.pdf

[55] *In the Matter of Public Utility Commission of Oregon, Investigation Into Integrated Resource Planning Requirements*, Docket No. UM 1056 (Jul 26, 2002), available at: https://apps.puc.state.or.us/edockets/docket.asp?DocketID=10081

[56] Docket No. UM 1056, Order 07-002 at 19 (Jan 8, 2007), available at: https://apps.puc.state.or.us/orders/2007ords/07-002.pdf

[57] *Id.*

[58] *In the Matter of Public Utility Commission of Oregon, Investigation Into Resource Adequacy in Oregon*, Docket No. UM 2143, Staff Report at 9 (Mar 24, 2022), available at: https://edocs.puc.state.or.us/efdocs/HAU/um2143hau154059.pdf

[59] *In the Matter of Alliance of Western Energy Consumers, Petition for Investigation Into Long-Term Direct-Access Programs*, Docket No. UM 2024, ALJ Ruling issued February 21, 2020, adopting phasing proposal, Attachment A, available at: https://edocs.puc.state.or.us/efdocs/HDA/um2024hda12440.pdf

uncertainties).[60] In addition to this investigation, Oregon investor-owned utilities and some ESSs are committed to the binding phase in the Western Power Pool's Western Resource Adequacy Program (WPP WRAP), as discussed in **Section 3.2, Regional planning: resource adequacy**.

The Commission's investigation into long-term direct access led to an Informal Rulemaking in October 2021 aimed at narrowing the scope of issues under consideration.[61] Topics included the definition of non-bypassability (ensuring customers cannot avoid shared public policy costs by taking direct access), how to calculate a non-bypassable charge, the utility's role as the provider of last resort (PGE is required to serve direct access customers should an ESS fail) and rules for implementation of HB 2021 for ESSs. The Commission moved into Formal Rulemaking in October 2022, focusing initially on addressing provider of last resort risk. Stakeholders are currently exploring the option of preferentially curtailing (disconnecting) a direct access customer if they return to the utility at short notice and there is insufficient power to serve them.

3.1.8 Regulatory policy: Power cost adjustment mechanism (PCAM)

The PCAM framework is a central element of PGE's process to adjust customer rates to recover variance in power cost compared to the annual forecast. The PCAM allows for collection from, or refund to, customers of the power cost variance subject to power cost deadbands, sharing and earnings deadbands.

The current PCAM structure was adopted for PGE in 2007.[62] It originated from a Commission-established set of principles envisioned to ensure a well-designed PCAM and an appropriate balance of power cost forecast risk between PGE and customers. Sixteen years later, the circumstances to which PGE is exposed have changed significantly with respect to a changing resource mix, the impacts of climate change and changing wholesale market dynamics.

With the requirements of HB 2021, PGE's energy supply portfolio is shifting from predominantly high capacity, base load and dispatchable generation to a portfolio composed of increasing amounts of non-dispatchable and variable renewable energy resources. The renewable resource additions to PGE's and the region's supply portfolios

[60] Docket No. UM 2143, *Investigation into Resource Adequacy in the State*, available at: https://apps.puc.state.or.us/edockets/DocketNoLayout.asp?DocketID=22698
[61] Docket No. AR 651, *In the Matter of Rulemaking Access Including HB 2021 Requirements*, Public Utility Commission of Oregon (Oct 1, 2021), available at: https://apps.puc.state.or.us/edockets/docket.asp?DocketID=23063
[62] *See* OPUC Order No.07-015 (Jan 12, 2007), available at: https://apps.puc.state.or.us/orders/2007ords/07-015.pdf

have been primarily wind generation (and some solar), which presents unique challenges with respect to predictability and coincidence with critical peak load conditions.

PGE's service area has experienced the impacts of climate change with increased frequency and magnitude of extreme weather events. Increasingly frequent severe weather events in peak months have resulted in a shift to energy demand with system record-setting loads experienced in 2021 and 2022 for utilities across the Western Interconnection.

These load excursions, coupled with the resource intermittency and the somewhat negatively correlated nature of most variable energy resources in the regional energy stack to high demand conditions caused by extreme weather, have stressed regional resource adequacy and exacerbated volatility in the market. During these events, PGE must serve higher load requirements and replace previously expected wind energy generally unavailable during very cold or hot temperatures.

Collectively, these changes increase the degree of power cost variability and create conditions that become difficult to predict or forecast. The frequency, duration and magnitude of disruptive events have led (and will continue to lead) to higher variability and extreme levels of power cost outcomes around any baseline forecast established initially in rates. PGE expects these circumstances to continue and potentially intensify as climate change drives more frequent severe weather events and we transform the energy system to achieve the decarbonization targets of 2030 and beyond. Regulatory policy can (and should) adapt to changing dynamics. Changing capacity constraints, load profiles, decarbonization policy and scarcity pricing necessitate revisiting the original PCAM principles and structure.

3.2 Regional planning: resource adequacy

Resource adequacy refers to planning to have enough resource generation, efficiency measures and demand-side resources to serve loads across a wide range of conditions with a sufficient degree of reliability.[63] Planning to be resource adequate is especially important as the region decarbonizes, as increasing penetrations of variable energy resources and retiring coal plants occur against a backdrop of increasingly extreme and unpredictable weather events. As states across the Western Interconnection decarbonize in response to state or utility-specific mandates or targets, resource adequacy increasingly depends on regional coordination.

The Western Power Pool (WPP) began gathering information about the need for a regional resource adequacy program in 2019, finding "[t]he impending retirement of several thermal

[63] For example, NARUC Resource Adequacy Primer for State Regulators, July 2021, defines the resource adequacy long-term (years, months) planning focus as being "[a]ble to meet demand with sufficient supply side and demand-side resources", p.5., available at https://pubs.naruc.org/pub/752088A2-1866-DAAC-99FB-6EB5FEA73042.

generators within and outside the region (the Western US and Canada) mixed with increasing variable energy resources (VERs), has led to questions about whether the region will continue to have an adequate supply of electricity during critical hours." These efforts led to the formation of the Western Resource Adequacy Program (WRAP), which began implementing a voluntary, non-binding (no penalties) program in October 2021. The earliest binding (charges for failure) season is scheduled for Summer 2025 (with participants providing an advanced 'forward showing' of their resource adequacy positions for that season in October 2024). Twenty-six load-responsible entities across 10 states and one Canadian province currently participate in WRAP development.

The WPP WRAP includes a forward-showing planning mechanism to identify the collective capacity needed to meet a 1-day in 10-year loss of load expectation (LOLE) target. The forward showing requires participants to plan and submit a portfolio of resources seven months ahead of operational need and will not replace the multi-year IRP planning process. PGE's IRP and the WPP WRAP use different methodologies, footprints and timeframes to assess capacity adequacy, currently leading to differing resource effective load-carrying capabilities (ELCCs) and other capacity-critical hours. The OPUC's investigation into resource adequacy could lead to a state-level framework that bridges the WRAP and IRP.

The forward showing aims to provide reliability benefits through consistent metrics and methodologies while providing increased visibility and transparency. PGE will still be responsible for determining what resources to procure from other participants and suppliers. Participants will demonstrate compliance with forward-showing reliability metrics seven months before binding seasons (summer and winter). They will be given three months to cure any resource adequacy planning deficiencies. The program will calculate the required planning reserve margin (PRM) to meet the LOLE target for each month of the binding seasons. Participants will then be required to show they have adequate resources (specified generation and contracts backed by specified generation) and enough firm transmission to meet their P50 (median) load plus the PRM during the months of the binding seasons. The charge for noncompliance and failure to cure the inadequacy will be based on the cost of new entry for a gas peaking plant.

At the end of 2022, PGE, along with a majority of other participating load-responsible entities, committed to continued support for the WPP FERC Tariff (rules of program, governance), which was filed in August 2022 and approved February 2023.

At the state level, the OPUC opened an investigation into resource adequacy in January 2021.[64] Throughout 2021, a state-level resource adequacy framework straw proposal was developed to complement the regional efforts in the WPP WRAP. The state framework would

[64] See *Investigation into Resource Adequacy in the State*, Docket No. UM 2143, Order 21-014 (Jan 13, 2021), adopting Staff Report with Appendix A, available at: https://apps.puc.state.or.us/orders/2021ords/21-014.pdf

be mandatory for Oregon electric investor-owned utilities and ESSs, require forward showing of resource adequacy more than seven months ahead of a season (to enable time for physical resources to be built), and could be in place sooner than a binding WPP WRAP (set to go binding no earlier than 2025).[65] This would bring ESSs more into line with what utilities like PGE already undertake in IRPs, providing the Commission with visibility into how direct access loads are being planned for to ensure resource adequacy. OPUC Staff and stakeholders resumed consideration of this state framework in the fourth quarter of 2022. The current potential schedule could see rules in place by mid-2023.

3.2.1 Resource adequacy in the IRP compared to the WRAP

As discussed in the previous section, PGE is participating in the WPP WRAP. Binding participation (with penalties for failure) can occur no earlier than Summer 2025, with a forward showing of resource adequacy seven months ahead in October 2024. As PGE prepares for binding participation in the WRAP, it is necessary to consider how the IRP and WRAP may need further alignment to avoid future conflicts. Lawrence Berkeley National Laboratory (LBNL) identified four key IRP assumptions that will be impacted by participation in regional resource adequacy programs like the WRAP: reliability targets; resource capacity accreditation; transmission assumptions; and load forecasting.[66] Even with participation in the WRAP, it is important to note that the IRP still defines the resources that PGE can use to meet capacity needs, reliability and emissions targets.

The WRAP has adopted the resource adequacy standard of one event in 10 years LOLE, while PGE's IRP uses a one day in 10 years LOLE as a reliability metric. These reliability targets will need to come into closer alignment as utilities approach binding participation in a regional resource adequacy program. If PGE's IRP resource adequacy target led to a lower capacity need than the WRAP, there is a risk of being modeled as adequate at the balancing-authority level but not at the regional level. This could lead to the utility having to justify additional investments outside its acknowledged Action Plan. States and the WRAP will likely need to reach a consensus around reliability targets for use in state-level IRP planning.

The assignment of a capacity credit to a resource will also need to be more closely aligned between the IRP and the WRAP before participation in the regional resource adequacy program becomes binding. WRAP uses a variety of resource-specific methodologies to calculate the qualifying capacity contribution of a participant's generation resources during

[65] Docket No. UM 2143, Staff's Process Proposal and RA Solution Straw Proposal, filed October 15, 2021, available at: https://edocs.puc.state.or.us/efdocs/HAH/um2143hah145744.pdf

[66] Juan Pablo Carvallo, Nan Zhang, Benjamin D. Leibowicz, Thomas Carr, Maury Galbraith, Peter H. Larsen. *Implications Of A Regional Resource Adequacy Program On Utility Integrated Resource Planning,* Energy Analysis and Environmental Impact Division, Lawrence Berkeley National Laboratory. November, 2020, available at: https://eta-publications.lbl.gov/sites/default/files/ra_paper_1_-_final_version.pdf

the region's capacity critical hours. PGE's IRP calculates the capacity contribution of individual resources using a stochastic model that optimizes resource generation to achieve a reliability objective. If an IRP relies on a different resource capacity accreditation methodology than that used regionally, there is a risk of different outcomes between state and WRAP adequacy assessments. A potential solution is for states and the WRAP to agree on capacity contribution values and incorporate them into IRPs.

The WRAP also considers the deliverability of power when determining a participant's resource adequacy. Any assumptions around transmission expansion should be consistent at both the IRP and the regional level, requiring increased coordination and information sharing between WRAP participants. There will also likely need to be increased standardizing on risk assumptions in load forecasts to avoid participants leaning on utilities that hedge more against forecast uncertainty.

PGE looks forward to working with WRAP participants and state regulators to ensure that state-level IRPs complement and work in harmony with regional resource adequacy programs.

3.3 Market, labor and supplier dynamics

The broader macroeconomic environment in the years following our 2019 IRP remains highly dynamic. While **Chapter 4, Futures and uncertainties** discusses a wide range of critical uncertainties addressed in IRP modeling directly, this section discusses additional trends contributing to market instability that impact PGE. Geopolitical unrest continues to contribute to volatile fuel markets and rising power costs for utility customers. Nationally and in Oregon, inflation remains high, labor markets are tight and the specter of economic recession looms. At the same time, PGE is experiencing highly localized growth in key areas of our service area. This imparts additional pressures on the transmission system, which is already highly constrained, as discussed in detail in **Chapter 9, Transmission**, and **Section 11.1.7, Transmission constraints**. Economic uncertainty, transmission constraints and labor and supply chain shortages may impact PGE's pace of acquisition and integration of non-emitting resources in the years ahead.

3.3.1 Localized load growth

Demand for data center capacity has grown exponentially across the globe and in the United States in the last 10 years, driven by factors such as the need for computing power, cloud and software-as-a-service offerings and entertainment. During that same time, certain areas of the PGE service area have become prime locations for data center siting. According to Cushman & Wakefield's 2023 Global Data Center Market Comparison, the Portland market jumped to a

tie for first place in the overall global standing this year.[67] We are seeing a rapid expansion of hyperscale activity in the Washington County submarket from new entrants and existing customers due to access to the Transpacific cable landing, relatively favorable pricing, sustainability options, low environmental risk, access to power and available land. This contrasts with primary markets, such as Northern Virginia and Silicon Valley, seeing power and land constraints.

In addition to data center demand, Oregon is a global leader in semiconductor manufacturing and R&D. Fifteen percent of US semiconductor manufacturing takes place in PGE's service area, with Hillsboro supporting the largest concentration of integrated device manufacturers and semiconductor innovation in Oregon. With the Federal Government's 2022 passing of the CHIPS & Science Act, billions of dollars of federal incentives have been made available to help spur unprecedented domestic investment in semiconductor manufacturing and development. Oregon is vying to bring its share of that investment to the state for the benefit of local jobs and economic development. It is anticipated that much of that investment will focus on the region PGE serves, particularly the North Hillsboro semiconductor ecosystem. Specifically, the Oregon Semiconductor Competitiveness Task Force has recommended the addition of two 500-acre parcels of land in the N. Hillsboro and North Plains area to support the location of major new semiconductor manufacturing facilities.

With both trends described previously, PGE is projecting significant hyper-local growth and surging electricity demand in these geographic areas. PGE is proud to have supported enormous business growth in Washington County and the Hillsboro area for many years, helping to pave the way for new jobs, revenue streams and opportunity for the state. To meet this continued rapid demand growth, PGE is working diligently to increase infrastructure capacity by collaborating with industry, stakeholders and customers to benefit Oregon's economy. These efforts include:

- Advancing more than a dozen transmission projects with significant involvement of local governments and jurisdictions, including the Bonneville Power Administration (BPA);
- Actively engaging with BPA to increase transmission capacity by collaborating to accelerate upgrades and reinforce key substations and transmission lines along our 230 kilovolt (kV) and 500kV systems. We are also working with BPA to identify new options for incremental capacity;

[67] Information about the Global Data Center Market Comparison is available at: https://www.cushmanwakefield.com/en/insights/global-data-center-market-comparison

- Engaging residential and commercial customers to add value to the grid by participating in programs that compensate customers for lending their flexibility to the operation of the grid; and
- Deploying grid edge technologies such as remote sensors, dynamic line ratings and the use of advanced conductor materials.

At the time of the writing of this IRP, demand forecasts for North Hillsboro are being reviewed to ensure PGE is working from the most accurate load forecasts possible. We are working to understand customer timelines and flexibility, particularly around load delivery during peak usage times, to respond to new large load requests.

3.3.2 Workforce availability

Oregon's transition to the clean energy future will require investments in thousands of megawatts of new non-GHG-emitting resources and the people to build them. Oregonians are not unique in their desire for clean energy along the West Coast, which will lead to competition for the existing workforce to build those resources. Recognizing the need to be proactive, in mid-2022, PGE convened the Oregon Clean Energy Workforce Coalition (OCEWC). The OCEWC is a statewide coalition that includes utilities, renewable developers, unions, workforce investment boards, state agencies, pre-apprenticeship programs, local and regional governments, education providers and community-based organizations. The collective mission of the OCEWC is to build the clean energy workforce pipeline by intentionally engaging with historically underrepresented populations in the energy sector, including women and people of color. Ensuring the workforce pipeline will be able to meet the demand for clean energy will require all stakeholders to work together to support investments in pre-apprenticeship programs and educational awareness about the availability of jobs within the sector.

3.3.3 Supply chain

Like other electric companies nationwide, PGE continues experiencing delays in securing the material needed for development, maintenance and reliability.

These delays continue to be driven by material availability, labor constraints, shipping and transportation issues, increased construction demand and extreme weather, all exacerbating factors.

The situation is dynamic and is expected to continue. Therefore, we've taken these steps:

- We continue to take steps to alleviate the shortage impact on customers by delaying non-critical work, seeking new sources and adjusting material on order.

- We are working with industry organizations (like the Edison Electric Institute) and partners to advocate for measures to help address the shortage of critical materials.
- Partnering with distributors and manufacturers to increase forecasting and material ordering.

We will continue exploring options toward finding a solution to these issues.

3.3.4 Department of Commerce investigation into solar tariff circumvention

On January 23, 2018, then President Trump placed tariffs on imported solar cells and modules (PV panels) from China. The tariff level was set at 30 percent, with a 5 percent decline rate per year over the four-year term of the tariff. On February 4, 2022, President Biden extended the tariffs another four years but made an exemption for bifacial panels (two-sided panels used predominated in the utility-scale solar market segment).

On March 28, 2022, the US Department of Commerce (US DOC) announced a year-long investigation, which was prompted by a February 2022 petition from US company Auxin Solar, into whether imports of solar panels from Southeast Asia (specifically Cambodia, Malaysia, Thailand and Vietnam) are circumventing the tariffs in place against China. The investigation could result in retroactive tariffs of up to 240 percent. Despite President Biden's exemption for bifacial panels in the tariff extensions, the investigation would impact all developments that involve crystalline silicon photovoltaic (CSPV) cells. About 80 percent of panels installed in the US in 2021 came from the four countries under investigation.

The US DOC announced its preliminary determination in December 2022 that four of the eight companies being investigated were attempting to circumvent the existing tariffs through each of the four Southeast Asian countries. The US DOC is scheduled to release a final determination, including the assessed duties, on May 1, 2023. President Biden issued a proclamation on June 6, 2022, which suspended the solar tariffs for two years. Therefore, duties cannot be collected on any solar import until June 2024.

The PV panel supply chain is likely to continue to experience disruption. Given the large share of PV panels originating in the Southeast Asian market, US-based developers may not find adequate supplies of replacement panels from other countries of origin. The limited supply of North American manufacturing capacity is largely sold through 2023, limiting the potential for alternative domestic supply to backfill Southeast Asian equipment. Amidst this supply chain disruption, solar developers are faced with disrupting choices, including 1) importing Southeast Asian panels and facing exposure to retroactive penalties, 2) sourcing panels from more expensive countries of origin, including China, whose PV panels are subject to ongoing tariffs, 3) waiting for the US DOC investigation to resolve.

Chapter 4. Futures and uncertainties

To meet the evolving needs of the electricity grid and customers, it is critical to assess the wide range of uncertainties impacting different elements within the power system. Estimating the compounded effects of the different drivers and their impacts is foundational to ensuring the robustness of our resource actions by minimizing risk over time for customers across a wide range of potential futures.

The previous chapter discussed the broader policy and macroeconomic environment in which we are creating these plans. In this chapter we detail how we are incorporating this environment, including all the associated uncertainty, into our IRP. First, we discuss the different Need Futures, which describes the range of resource needs in terms of capacity and energy. This is followed by descriptions of the variation in technology costs of resources and wholesale electricity prices. This approach informs how resource actions taken by Portland General Electric (PGE) will account for future risks and uncertainties.

Chapter highlights

- Key drivers of uncertainty in this Integrated Resource Plan (IRP) include demand growth, economic trends and technological innovation, rate of electrification and customer adoption of new technologies, regional resource adequacy and buildout of new non-GHG-emitting resources.
- PGE's portfolio analysis accounts for uncertainty in future resource needs, technology costs, wholesale energy markets and hydro conditions.
- Portfolio analysis was conducted across 351 potential futures, defined by the range of resource needs, technology costs and wholesale electricity market prices

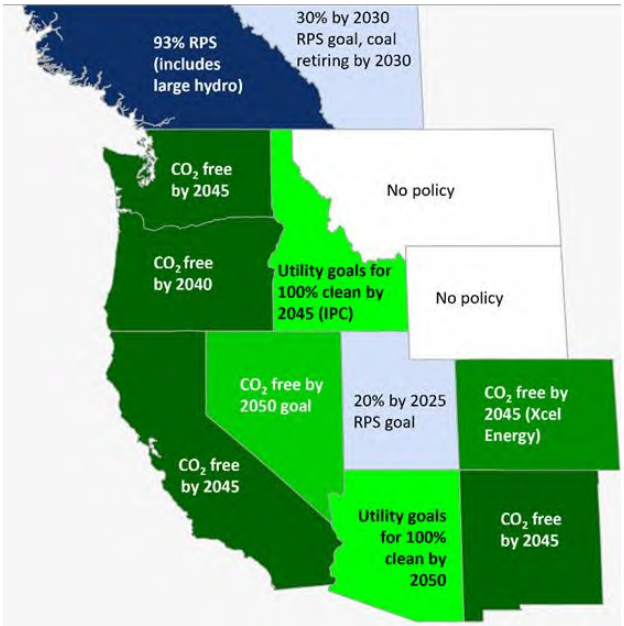
4.1 The changing Western Interconnection

The power system landscape across the Western Interconnection is changing rapidly.[68] At the start of 2018, there were no policies in the West that mandated a 100 percent clean/non-GHG-emitting power system. In September 2018, California signed Senate Bill (SB) 100 into law, which directed the state to reduce electric system GHG emissions to zero by 2045.[69] In

[68] Information about the Western Interconnection is available at: https://www.wecc.org/epubs/StateOfTheInterconnection/Pages/The-Western-Interconnection.aspx
[69] CA Senate Bill (SB) 100 (2018), available at: https://www.energy.ca.gov/sb100

the following years many states, including Oregon in 2021, passed similar bills targeting a non-emitting power system in the 2040s (**Figure 17**).[70] Additionally, several utilities in states without clean energy policies have made company-level decarbonization pledges.[71] **Figure 17** shows key state-level GHG reduction and renewable portfolio standard policies.[72] These policies will likely bring more wind, solar, storage and other non-emitting resources to the West and transition away from coal and gas-fired generation.

Figure 17. Western clean energy policies



Forecasting Western energy markets requires predicting how quickly non-GHG-emitting resources will arrive and how quickly GHG-emitting generation will decrease, considering market and transmission interoperability issues, and assessing if the transition creates adequacy challenges. Resource adequacy challenges have occurred in recent years in the Western Interconnection. In California, the California Independent System Operator (CAISO) system experienced blackouts in August 2020 and issued a Stage 3 emergency alert in September 2022.[73] Prior to 2020, CAISO had yet to issue a Stage 3 alert since the 2001 energy crisis. Due to reliability concerns, California passed AB 205 in the summer of 2022, which includes an electric reliability reserve fund, among other provisions. California also

[70] OR: HB 2021 (2021); WA: SB 5116 (2019); NM: SB 489 (2019); NV: SB 358 (2019); and CO SB 19-236 (2019).
[71] Available at: https://www.idahopower.com/news/idaho-power-long-range-plan-focuses-on-reliable-affordable-clean-energy/, and at https://www.aps.com/en/About/Our-Company/Newsroom/Articles/APS-sets-course-for-100-percent-clean-energy-future, January 22, 2020
[72] Policies listed on the map may not apply to smaller power providers; additional policies may exist.
[73] A Stage 3 alert indicates blackouts are imminent.

passed SB 846 in 2022, which attempts to extend the life of the Diablo Canyon nuclear power plant, mainly for grid reliability.[74]

Beyond the changing supply side landscape, there is uncertainty regarding Western electric demand. Many states and municipalities have passed laws encouraging and/or mandating building and vehicle electrification that could bring new loads to the Western Interconnection. For example, Oregon, Washington and California are banning the sale of gasoline passenger vehicles by 2035, accelerating the push toward electric vehicles.[75] In spring 2022, Washington amended its building codes to require electric heating in most large multifamily construction and commercial buildings.[76] These policies, which aim to reduce GHG emissions, may lead to increased demand for electricity. Beyond electrification, the Northwest has also seen increased demand for electricity in recent years from industrial customers, often in the form of data centers.

In late 2019, the Western Power Pool (then the Northwest Power Pool) reviewed reliability studies conducted by BPA, Energy and Environmental Economics, Inc. (E3), Pacific Northwest Utilities Conference Committee (PNUCC) and the Northwest Power and Conservation Council. The studies "identify an urgent and immediate challenge to the regional electricity system's ability to provide reliable electric service."[77] They also note that "studies have shown that it is possible to cost-effectively replace coal generation with… lower carbon resources and significantly reduce electricity sector carbon emissions."[78]

The Western Power Pool's findings helped spur the creation of the Western Resource Adequacy Program (WRAP). The WRAP is still under development. If it succeeds, it may change how the IRP examines power market availability, resource adequacy and resource capacity contributions (more information on the WRAP is in **Section 3.2, Regional planning: resource adequacy**).

As part of the Western Interconnection, PGE routinely buys and sells power with other Western power market participants. As noted earlier in this section, predicting how much power will be available to buy and sell in future years is challenging. However, the IRP considers short-term power markets as a resource adequacy tool. To accomplish this, the IRP includes an analysis that approximates how much power will be available in future years during peak hours. This analysis focuses more on power availability in Oregon, Washington,

[74] Available at: https://www.utilitydive.com/news/california-sweeping-climate-package-carbon-neutrality-2045-clean-electricity-2035-diablo-canyon/631099/
[75] Available at: https://www.oregon.gov/deq/rulemaking/Pages/CleanCarsII.aspx
[76] Available at: https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/washington-state-to-require-electric-heating-in-building-code-update-69960737
[77] See "Exploring a Resource Adequacy Program for the Pacific Northwest", Northwest Powerpool, October 2019, at page 7, available at: https://www.westernpowerpool.org/private-media/documents/2019.11.12_NWPP_RA_Assessment_Review_Final_10-23.2019.pdf
[78] *Id.* at page 8.

Idaho and Western Montana and is used as an input into the resource adequacy model, Sequoia, that determines PGE's need for power. More information on the analysis is in **Appendix G, Market capacity study**.

For the Reference Case, the amount of market power available to the Sequoia model is in **Table 6.** Heavy load hours defined as 6:00 AM to 10:00 PM, Monday-Saturday, excluding holidays. Light load hours are all other hours. The light load hour range is dependent on load (lower load is associated with more market availability). The decrease in winter market availability starting in 2026 is largely due to coal unit retirements.[79]

Table 6. PGE 2023 IRP spot market power availability assumptions for resource adequacy

All values in MW	2025 and earlier		2026 and later	
	Winter	Summer	Winter	Summer
Heavy load hours	200	0	150	0
Light load hours	400-999	400-999	400-999	400-999

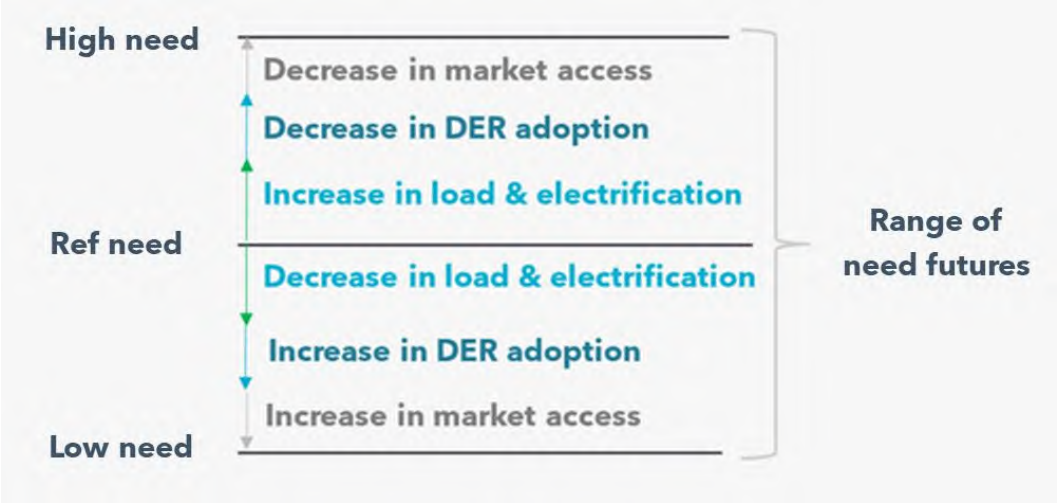
4.2 Need Futures

One of the two key objectives of the IRP process is to estimate system need under a variety of scenarios.[80] The IRP creates individual Need Futures that aggregate the impact of load growth, distributed energy resources (DERs) and market access assumptions. Different permutations of the load, DERs and market access assumption form the basis for the range of Need Futures in the IRP. The range of Need Futures is a vital input to determine the robustness of the proposed set of resource additions to a variety of conditions. The Need Futures not only capture the costs and risks associated with large and long-lived resource actions given the uncertainty in future resource needs but also highlight critical considerations for PGE's non-GHG-emitting resource procurement strategy.

PGE designed the Need Futures to capture a broad variation from the Reference Case by varying drivers that would impact the resource need.[81] **Figure 18** visually represents the driving variables that change the Reference Case to the High and Low Need Futures.

[79] The coal fired Centralia Unit 2 and Valmy Unit 2 are expected to retire at the end of 2025.
[80] The other key objective is to propose the optimal combination of resources, their size and timing, to address the identified system need. This culminates in **Chapter 11, Portfolio analysis**.
[81] The Reference Case refers to the collection of assumptions made across all applicable variables. These assumptions were made based on analysis and studies. Low and High Case assumptions are applied in relativity to the Reference Case.

Figure 18. Visualization of the range of Need Futures captured within the IRP



Articulated in this section is a comprehensive list of variables that result in the three Need Futures, which are summarized in **Table 7.**

- **Top-down Load Forecast.** This IRP considers three scenarios related to macroeconomic and policy trends and impacts on future loads. In addition to the reference load forecast, the low and high growth scenarios capture uncertainty in economic drivers and forecast model uncertainty. The top-down load forecast and associated high and low growth scenarios are detailed further in **Section 6.1, Load forecast,** and **Appendix D, Load forecast methodology**.
- **Energy Efficiency.** This IRP considers three scenarios related to energy efficiency adoption. In addition to the Reference Case, the Low Need Future assumes a higher acquisition of energy efficiency than the Energy Trust of Oregon's (ETO's) cost-effective forecast based on the ETO's high avoided cost scenario (which assumes a 25 percent increase in avoided costs as defined by UM 1893).[82] Similarly, the High Need Future is based on Energy Trust's low avoided cost scenario, which assumes a 25 percent decrease in avoided costs relative to the Reference Case. Energy efficiency that was deemed cost-effective by ETO is discussed in **Section 6.2, Distributed Energy Resource (DER) impact on load**.

[82] *In the Matter of Public Utility Commission of Oregon, Investigation Into the Methodology and Process for Developing Avoided Costs Used in Energy Efficiency Cost-Effectiveness Tests*, Docket No. UM 1893, available at: https://apps.puc.state.or.us/edockets/DocketNoLayout.asp?DocketID=20999

- **Market Capacity.** This IRP considers three scenarios for the availability of capacity from the market across seasons, years and hours of the day. The High Need Future assumes reduced market capacity, indicating the minimal ability to serve load via market purchases during summer and winter high load hours. Conversely, the Low Need Future assumes higher market availability during the high load hours in summer and winter. These assumptions are based on the findings and recommendations in **Appendix G, Market capacity study**.

This IRP leverages the analytical work within PGE's Distribution System Plan Part 2 (DSP) to determine the range of impact of DER, using it as the primary source of data for the adoption of rooftop PV, building and transportation electrification loads and their integration with PGE through demand response programs.[83]

- **Distributed Photovoltaics (PV).** This IRP aligns with the three adoption cases developed within the DSP. High adoption of PV results in a lower resource need and is consequently included in the low Need Future. Similarly, low adoption of solar PV is included in a high Need Future, as shown in **Table 7**.
- **Transportation Electrification (TE) Load.** High TE adoption results in a higher resource need and is included in the high Need Future. Conversely, low adoption of TE load is included in the low Need Future.
- **TE-related Demand Response (DR) programs.** Unlike TE load, the low participation in TE-related DR programs is included in the High Need Future to ensure we capture the broadest range of potential futures. However, in the Low Need Future, we use a Reference Case of the adoption of TE-related DR programs because the low adoption of EVs would not have sufficient vehicles to be combined with a high adoption of TE-related DR programs.
- **Demand Response (DR).** Like energy efficiency and PV, this IRP models an inverse relationship between Need Futures and customer participation in DR programs.[84]
- **Building electrification (BE) Load.** This IRP introduces three BE load adoption scenarios to align with the DSP's adoption scenarios, so the high adoption scenario of BE load is included in the high Need Future.

[83] PGE's Distribution System Plan Part 2, available at: https://apps.puc.state.or.us/edockets/edocs.asp?FileType=HAD&FileName=um2197had151613.pdf&DocketID=23043&numSequence=21

[84] High adoption of demand response programs results in lower needs and low adoption of demand response programs results in higher needs. The customer adoption of batteries is included within the demand response variable of each Need Future.

- **BE-related Demand Response (DR) programs.** However, just as with TE-related DR load, low participation in BE-related DR programs is included in the High Need Future to ensure we are capturing the broadest range of potential futures, and in the Low Need Future, we use a Reference Case of the adoption of BE-related DR programs creating an appropriate lower bound to the Need Future.

Table 7. Need Future variables

	Low need	Reference need	High need
Top-down Load Forecast	Low growth	Reference	High growth
Energy Efficiency	High EE	Reference	Low EE
Distributed PV	High adoption	Reference	Low adoption
Transportation Electrification (TE) load	Low adoption	Reference	High adoption
TE-related DR programs	Reference	Reference	Low adoption
Demand Response programs	High adoption	Reference	Low adoption
Market capacity	High availability	Reference	Low availability
Building electrification load	Low adoption	Reference	High adoption
Building electrification-related DR programs	Reference	Reference	Low adoption

In addition to the three Need Futures, PGE examined sensitivities to provide insight into other uncertainties that may impact need. These are described in **Section 6.10, Need sensitivities**.

4.3 Energy technology capital cost scenarios

Throughout **Chapter 2, Accessing support for energy transition** and **Chapter 3, Planning environment**, PGE describes the developments since the 2019 IRP that impact the current and expected costs of resources:

- Tax credit changes (see **Section 2.1, Federal support for energy transition**)
- Clean Energy Policy (a reference to **Section 3.1, Federal and state law and regulatory policy**)

Capital cost estimates are uncertain. Evaluating this capital cost uncertainty in a period of rapid technological change, inflation and supply chain shortages is critical to creating a long-term plan robust to potential changes. In addition to the reference costs (see **Chapter 8, Resource options**, and **Appendix M, Supply-side options**), PGE uses low and high capital cost trajectories for supply-side resources. Reference Case trajectories are primarily informed by the Energy Information Administration (EIA) 2020 Annual Energy Outlook (AEO) and the National Renewable Energy Laboratory (NREL) 2021 Annual Technology Baseline (ATB) analyses.[85,86] The high- and low-cost sensitivities generally rely on the scenarios presented in the NREL ATB; however, resource-specific assumptions are discussed in **Appendix M, Supply-side options**. Capital costs are included in PGE's IRP resource modeling via the revenue requirements model (**Section 10.1, Fixed costs**).

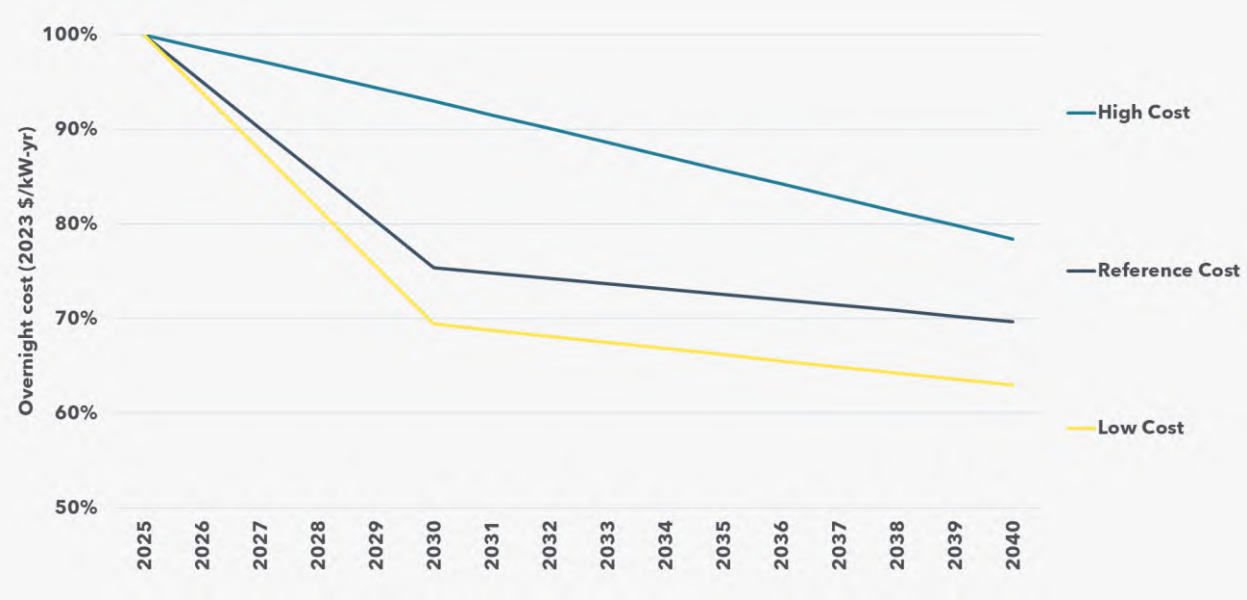
NREL summarizes the general technology innovation scenarios as follows:[87]

- Conservative scenario (high cost) In the NREL ATB Conservative scenario, historical investments come to market with continued industrial learning. The technology available is similar to the current day with a few technological innovations. Public and private investment in research and development (R&D) decreases.
- Moderate scenario (reference) NREL ATB describes this scenario as the expected level of technological innovation. The innovations observed in today's marketplace have become more widespread, and nearly market-ready innovations have come into the market. Public and private R&D investments continue at the current levels.
- Advanced scenario (low cost) Innovations far from market-ready today are successful and have become widespread in the NREL ATB Advanced scenario. Innovative technology architectures could look different from those observed today due to increased public and private R&D investment.

To illustrate the relationship between these three technology capital cost scenarios, fixed cost trajectories for the Christmas Valley Solar resource under each are presented in **Figure 19**.

[85] EIA 2020 Annual Energy Outlook, available at: https://www.eia.gov/outlooks/archive/aeo20/
[86] NREL 2021 Electricity ATB, available at: https://atb.nrel.gov/electricity/2021/index
[87] NREL 2021 Electricity ATB, available at: https://atb.nrel.gov/electricity/2021/definitions

Figure 19. Christmas Valley solar resource overnight cost trajectory (2023$)



See also the discussion of technology costs with respect to the Scenarios discussed in **Chapter 11, Portfolio analysis**.

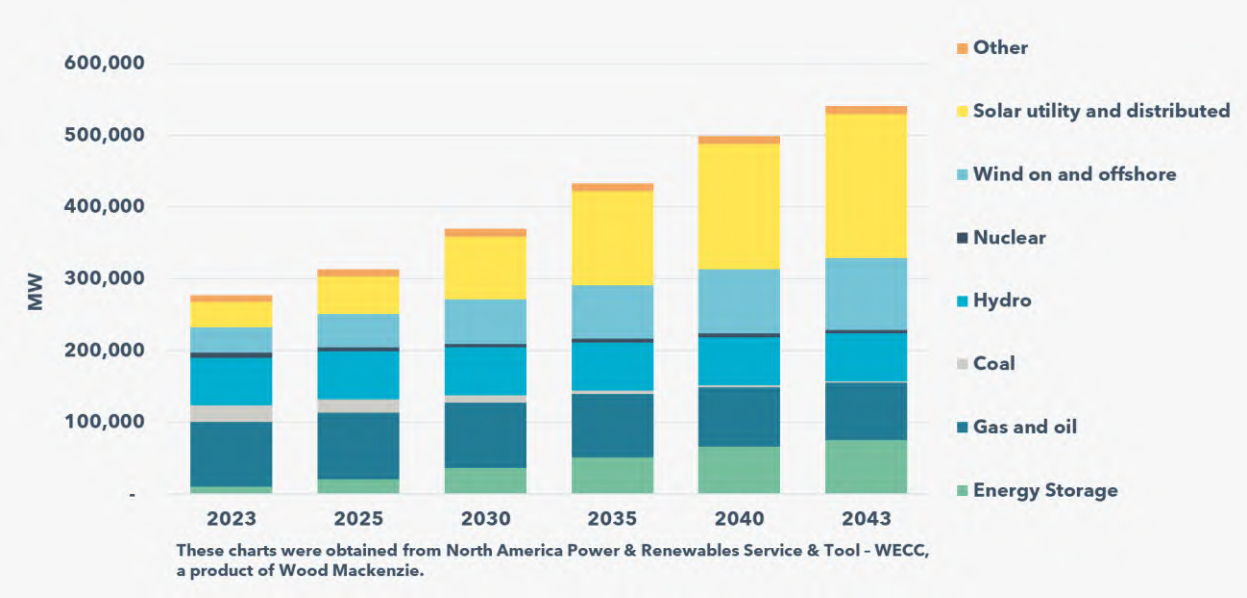
4.4 Long-term fundamental price forecast

The natural gas price forecast strongly influences the forecast of wholesale market prices for electricity.[88] PGE relies on the expertise of a power research consultancy, Wood Mackenzie (WM), to project the Western Electricity Coordinating Council (WECC) resource development and its impact on electricity prices in this IRP. Consequently, PGE incorporates WM's natural gas price forecasts into its long-term price forecasts, which reflects a declining reliance on the thermal fleet in the WECC as the region transitions to non-GHG-emitting resources. PGE also uses WM's WECC resource buildout outlook, shown in **Figure 20.**

The figure reflects the magnitude of the WECC effort to decarbonize, with resource additions being mainly renewables and storage. While the contribution share of gas and oil capacity is forecasted to decline over time as loads increase and non-GHG resources are brought on-line, the capacity of gas and oil capacity remains steady. The WECC capacity will nearly double the current level by 2043, with solar having the majority share and on and offshore wind being the next major contributor.

[88] Coal price forecasts have some influence on the wholesale electricity prices up until the end of 2029 as PGE's candidate resource portfolios include a coal-fired resource, Colstrip, that PGE is set to exit by January 1, 2030.

Figure 20. WECC capacity installed by year and generation source



PGE benefitted from extensive discussions on our electricity price forecasts with stakeholders in several IRP Roundtables.[89] These identified the following risk drivers to be considered in the IRP forecasts:

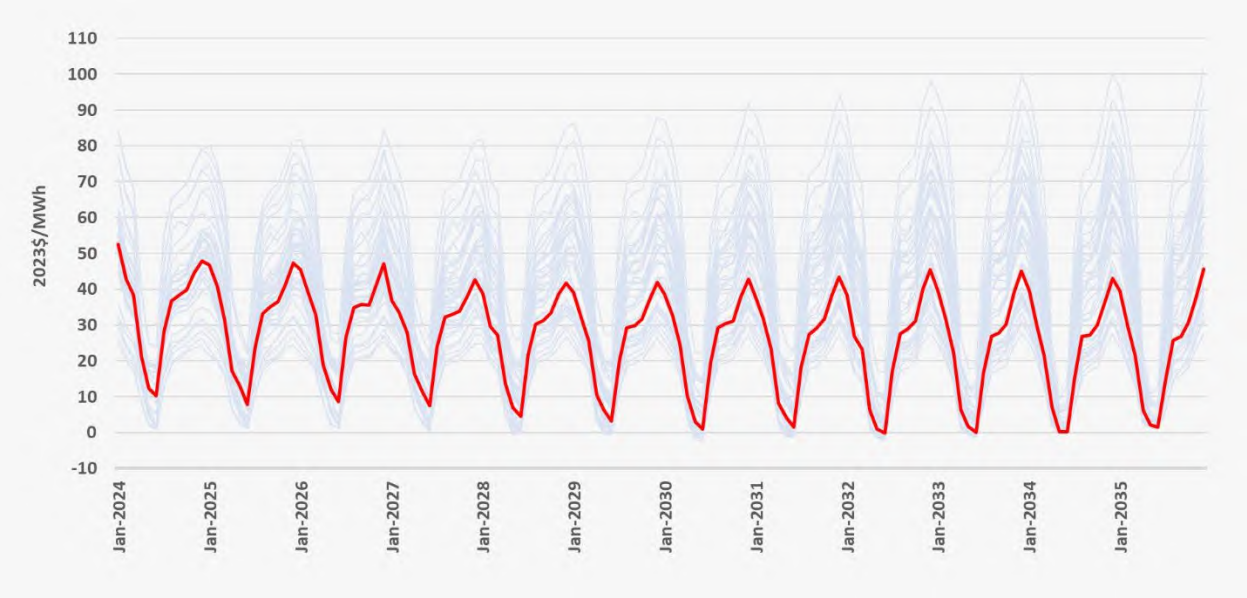
1. Gas prices and hydro conditions
2. Cost of compliance with carbon policies
3. Uncertainty in net load
4. Scarcity of committed dispatchable resources

PGE used the planning software Aurora with the WM WECC assumptions to generate 39 electricity price futures from permutations of risk drivers and carbon policy. This analysis aimed to identify a reference electricity price and a range of reasonable electricity prices in the Pacific Northwest in the next 20 years.[90] **Figure 21** displays forecasted monthly average electricity prices for each future, with the red reflecting reference prices. Simulated electricity prices then become an input for dispatch of existing PGE resources and are used to create energy value for new candidate resources.

[89] See **Appendix C.1.3, 2022 Public meetings** and **Appendix C.1.4, 2023 Public meetings** for more detail

[90] To reflect plausible scenarios in the simulation model, PGE capped energy prices at $1000 per MWh to reflect the price level that would trigger the FERC to investigate the incremental price increase. For price futures where significant commitment errors are considered and may consequently observe frequent breaches to the price cap, PGE reduced the price cap to $250 per MWh to reflect the price experienced during the 2000 energy crisis.

Figure 21. Average annual PNW electricity price futures



Results suggest that the forecasted growth in renewable generation resources across the WECC will generally reduce annual average prices, but the variability associated with their generation profiles will have a significant impact throughout the planning horizon. Winters continue to be forecasted times of high average monthly prices. The months of May and June exhibit low average monthly prices given low demand and high generation supply. The large distribution of potential market outcomes of forecasted prices highlights the uncertainty in forecasts of economic conditions. An important consideration is that IRP price forecasts do not necessarily represent the operational prices that utilities might face in real time due to the operating conditions utilities face and the unpredictable forward procurement costs. Instead, the IRP's forecasted prices are the results of a balanced system and normal conditions, and they benefit from a good forecast of load and renewable production. The prices are representative of hour-of-dispatch cost once reserves are procured. The long-term assumption is that the system finds adequate supply to meet demand and reserves. In contrast, operational prices do not have any of the mentioned elements. Operational prices, instead, are strongly dependent on short-term market variables.[91]

[91] Short-term market variables are factors that influence the operational prices of natural gas because of shocks to the supply or demand side of the natural gas market. These shocks, for example, could be caused by weather events or political events that increase or decrease the level of supply or demand in energy markets.

Acknowledging that our model will likely not accurately predict actual prices, PGE forecasted hourly prices with a variety of market price drivers: the quantity of available renewable capacity across the WECC, carbon policies, natural gas prices and hydropower generation in the Pacific Northwest. **Section 4.5, Uncertainties in price forecasts,** describes these market price drivers in more detail.

4.5 Uncertainties in price forecasts

PGE uses a scenario approach to model economic and technological uncertainty. In this section, we describe the risks and uncertainties that are evaluated in price forecasting, along with the price futures summarized in **Section 4.4, Long-term fundamental price forecast**.

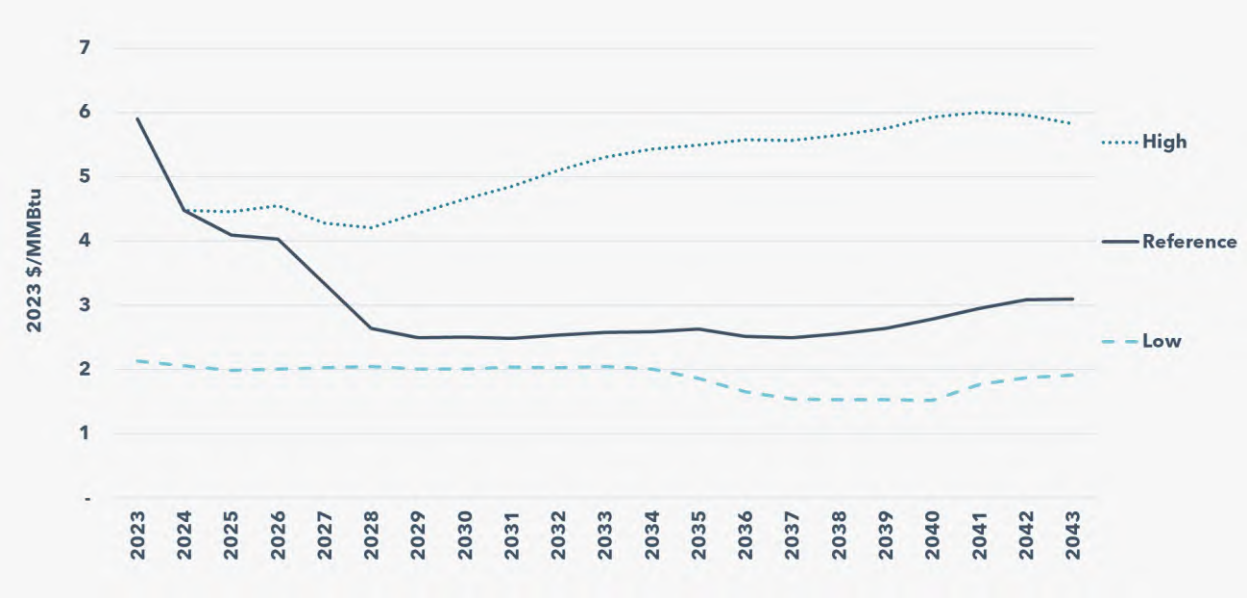
4.5.1 Commodity risk: natural gas prices

The price of natural gas has been and will continue to be a significant driver of wholesale electricity prices as natural gas-fueled power plants are used to meet loads, particularly during times of energy scarcity. The marginal units of power generated by natural gas-fueled power plants often set the market clearing price. While the contribution of gas-fueled power plants in the WECC declines in a high-renewable transition, the capacity of individual plants remains unchanged. With the significant increase of energy scarcity events, the forecasted price and availability of natural gas will continue to influence the electric power market while storage resources are not yet long-term multi-day capable.

PGE updated the gas price forecast input with Wood Mackenzie's long-term gas price forecast available in June 2022 to reflect the market sentiment prices following Russia's invasion of Ukraine in February 2022. The war triggered market volatility as the global sanctions against Russia's gas supply and increased export of liquefied natural gas (LNG) put a strain on the US oil and gas supply, causing historically high gas prices. WM's forecast also reflects the expectation of declining natural gas demand as states transition away from fuel-powered plants toward renewable generation.

Figure 22 shows the resulting Sumas hub gas price levels and trends. When simulating WECC prices, all gas hubs are input using the same input methodology previously described so that all WECC hubs are stressed simultaneously.

Figure 22. Natural gas price forecast Sumas Hub



4.5.2 Commodity and scarcity risk: hydropower generation

Hydropower generation (hydro) in the Pacific Northwest also strongly influences electricity prices. In addition to average hydro, PGE simulated a high and low hydro future. The average hydro is the Wood Mackenzie default and equal to the 2000-2011 average generation published by EIA. High hydro is 10 percent more than default and low hydro is 10 percent lower. See **Appendix H, 2023 IRP modeling details**, for more detail on this assumption. This hydro generation variability assumption is in line with the results observed in **Ext. Study-III, Climate adaptation**.

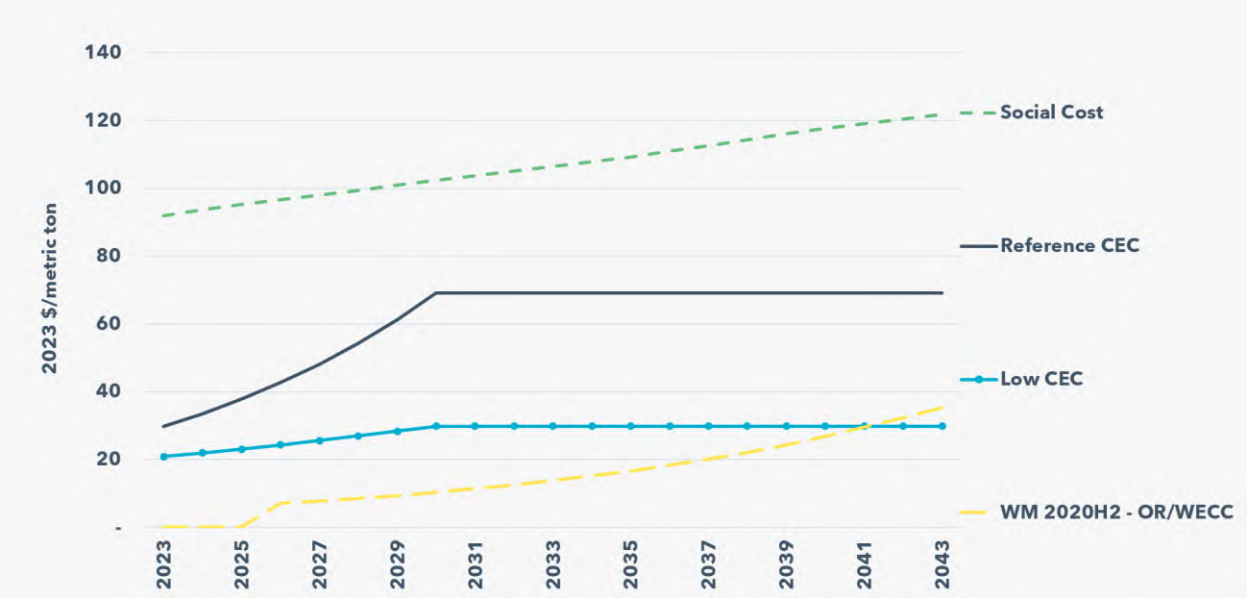
4.5.3 Carbon policies and emissions targets in WECC

This section explains how PGE modeled carbon price risk to market prices and unit dispatch simulations. PGE developed carbon adders to represent the cost of carbon policy compliance on power generation. These adders are added to dispatch cost based on individual resource fuel type and location.[92] The carbon adders are incorporated into three different carbon futures for the US portion of the WECC:

[92] A carbon adder is a modeling step in the PGE Zone Model (PZM) simulation where a cost is added to the dispatch cost of a carbon-emitting resource proportional to its emissions rate.

- Reference Case: No carbon adders are applied to WECC except for California and Washington, where there is existing carbon pricing legislation. California and Washington carbon adders apply the 2019 Reference GHG Allowance Price Projections published by the California Energy Commission (CEC).[93]
- Low carbon: No carbon adders are applied to WECC except for California and Washington, where there is existing carbon pricing legislation. California and Washington carbon adders apply the 2019 Low GHG Allowance Price Projections published by the California Energy Commission (CEC).[94]
- High carbon: California, Washington and Oregon apply the social cost of carbon (SC-CO2) defined by the United States Environmental Protection Agency (US EPA) and other federal agencies.[95] PGE selected 2.5 percent as the discount rate in intergenerational discounting to represent the social cost of carbon. For the rest of WECC, PGE applied Wood Mackenzie's reference carbon adder forecast to proxy for the cost of compliance with new carbon regulation.[96]
- Across each future, British Columbia and Alberta have a carbon tax adder that reflects Canadian legislation. **Figure 23** shows the forecasted level of the carbon adders.

Figure 23. Carbon adders in WECC economic analysis



[93] CEC's Integrated Energy Policy Report (IEPR) 2019, available at: https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2019-integrated-energy-policy-report
[94] *Id.*
[95] See, The Social Cost of Carbon, US Environmental Protection Agency, available at: https://19january2017snapshot.epa.gov/climatechange/social-cost-carbon_.html
[96] Wood Mackenzie 2020H2 WECC Carbon Adder Forecast, shown in **Figure 23**.

4.5.4 Uncertainty and scarcity risk

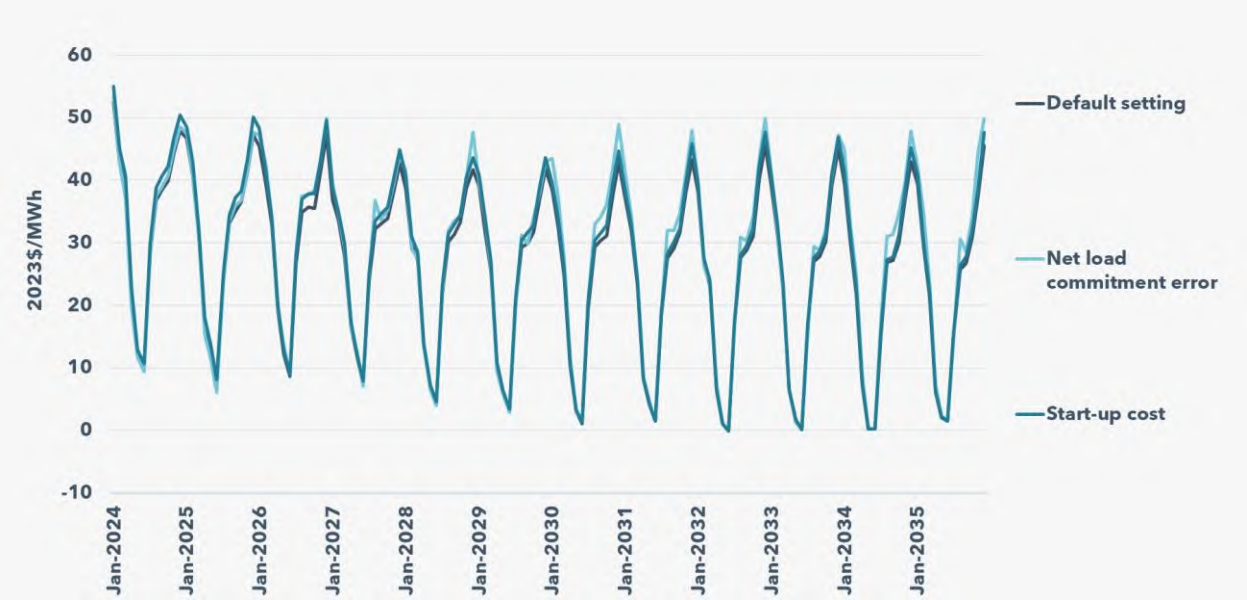
An important outcome of the public process leading to this IRP was the recognition of a disconnect between operational prices and fundamentals forecast, as mentioned in **Section 4.4, Long-term fundamental price forecast**. Traditionally, fundamental models do not embed operational difficulties experienced in actual operations as the model assumes that new dispatchable resources can be added to overcome operational obstacles. However, stakeholders and PGE agreed that the energy transition to non-dispatchable new additions would likely result in increasing difficulty in committing the resources at the right time. This volatility and scarcity price premiums have never been modeled in PGE's IRP. Hence, PGE created resource imbalance and scarcity premiums on prices by:

- **Introducing commitment error.** PGE purposely input a discrepancy between the wind forecast and the actual wind generation to represent the possibility of not having the right resources online and ready to generate when the net load is not what is expected. A 15 percent increase or decrease forecast error is randomly imposed on wind nameplate capacity hourly.
- **Adding start-up costs to simulated prices.** In our model, electricity prices are set by the marginal cost of the most expensive resource in the stack that is used to meet loads. When capacity is scarce, the marginal cost might underestimate prices, which demands a trade/bidding premium. We add the start-up cost to prices to reflect this premium.

This approach attempts to mimic the large generation and load swings with limited spare dispatchable resources. Additionally, we anticipate the magnitude of intermittent generation is and will increasingly be unprecedented, and climate change's impact on load, hydro and wind generation is largely unknown. The uncertainty and scarcity risk drivers were discussed in the April 22-3 roundtable, and more modeling detail is described in **Appendix H, 2023 IRP modeling details**.

Figure 24 illustrates the average electricity prices of the 39 price futures created in the WECC-wide Aurora simulation, organized into three categories: no modeling input, net load commitment error and start-up cost price futures. There is a pattern of more volatile electricity prices in the summer when net load commitment error, represented in light blue, is introduced. **Appendix H, 2023 IRP modeling details**, compares the intra-month hourly price range of reference and reference price future with start-up cost introduced.

Figure 24. Monthly average electricity prices across modeling specifications



By combining all the economic risk factors previously listed, we generated 39 price futures identified by a four-letter code for each risk model shown in **Table 8**.

Table 8. Simulated price futures

	Aurora Setup			Carbon Adder			Gas Price Forecast			Hydropower Generation		
	WM Model	Start-up cost	Net load commitment	Reference	Low	High	Reference	Low	High	Reference	Low	High
Number of price futures with risk factor	27	6	6	21	9	9	15	9	15	13	13	13

4.6 Addressing uncertainties

When the Capacity Need, Market Price and Technology Cost Futures are considered together, they explore a wide range of potential future conditions that influence the size and timing of resource additions. **Table 9** describes how these 39 price futures are combined with three Need Futures and three technology cost futures to consider 351 unique futures for each portfolio. Conducting portfolio analysis across these 351 alternative futures allows us to evaluate portfolios that meet system needs across a wide range of potential futures and score them based on cost and risk performance. While cost and risk metrics vary across all futures, resource builds do not vary by hydropower condition.

Table 9. Number of futures evaluated in portfolio analysis

	Market Price Futures		Capacity Need Futures		Technology Cost Futures		Total Futures Evaluated
Number of Futures	39	x	3	x	3	=	351

The WECC-wide simulation (conducted in Aurora) process is the first step to portfolio analysis and GHG emission forecasting. The simulated WECC electricity prices of the 39 price futures become the input for the PGE Zone Model simulation. Sequentially, the economic dispatch simulation results of new resources become inputs for the capacity expansion model, ROSE-E and the results of GHG-emitting resources become inputs for GHG emission forecasting. The following section discusses the GHG emission forecasting process in greater detail, and **Appendix H, 2023 IRP modeling details** explains the construct and relationships among models.

Chapter 5. GHG emissions forecasting

Under House Bill (HB) 2021, Portland General Electric (PGE) must reduce its greenhouse gas (GHG) emissions associated with electricity sold to Oregon retail customers. This chapter begins with a discussion of historical GHG emissions and the HB 2021 GHG targets. It then moves to describe the emissions reporting requirements of the Oregon Department of Environmental Quality (ODEQ). Finally, this chapter describes the emissions forecasting process that follows the ODEQ methodology and highlights five GHG reduction glidepaths PGE is studying as part of the 2023 Integrated Resource Plan (IRP).

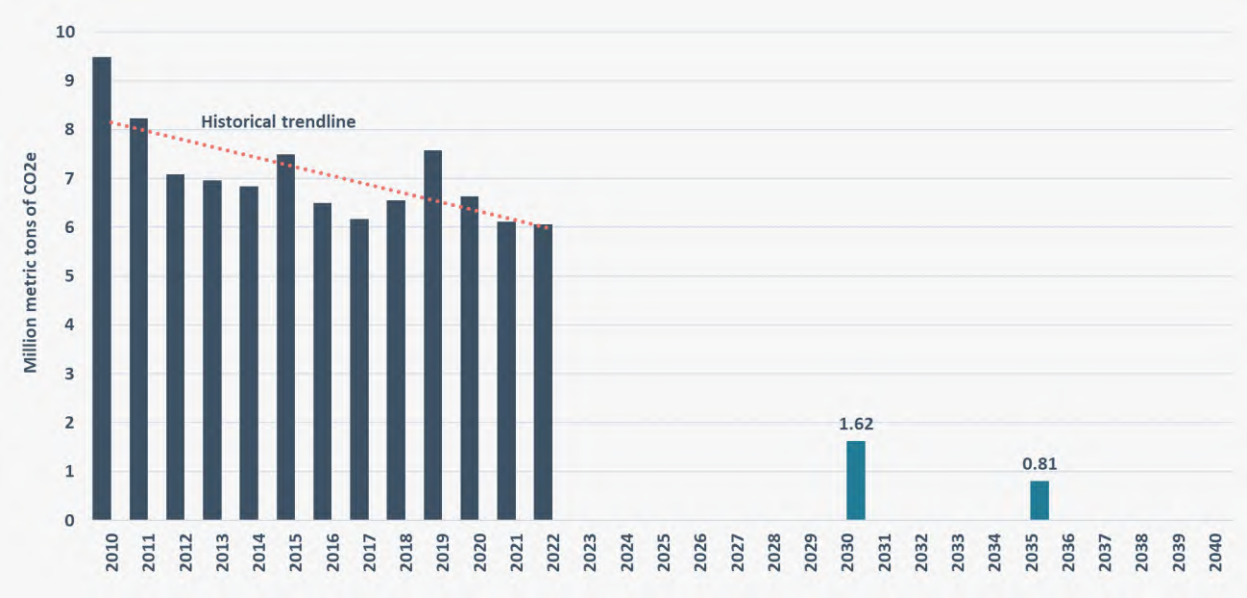
Chapter highlights

- HB 2021 sets 2030, 2035 and 2040 greenhouse gas (GHG) targets for energy associated with PGE retail load of 1.62, 0.81 and zero million metric tons of GHG emissions, respectively.
- PGE reports its GHG emissions associated with sales to Oregon retail customers to the ODEQ annually, and those reported emissions will be the basis for determining compliance with HB 2021.
- New for the 2023 IRP, PGE uses an Intermediary GHG model to account for differences in regulation of GHG emissions associated with serving Oregon retail customers and wholesale market sales.
- The IRP studies five different glidepaths for GHG reductions. Actual emissions may differ from those predicted here due to weather, resource procurement realities and other factors.

5.1 HB 2021 targets

House Bill (HB) 2021 sets Greenhouse Gas (GHG) emissions targets for PGE to meet. PGE must reduce GHG emissions associated with Oregon retail load as reported under ORS 468A.280 to 1.62 million metric tons CO2 equivalent (CO2e) by 2030, 0.81 million metric tons by 2035 and zero metric tons by 2040 and every year after. **Figure 25** shows PGE's historical GHG emissions under ORS 468A.280 and the HB 2021 targets.[97] As of the close of 2022, PGE's emissions have already fallen 25 percent from the baseline emissions level of 8.1 MMTCO2e.

Figure 25. Historical emissions for Oregon retail load service and HB 2021 targets



GHG emissions from generation and power purchases fluctuate year to year, often due to variations in economic conditions, temperature, wind/solar conditions, water conditions and other factors beyond the control of PGE. For example, higher-than-expected temperatures can increase the need for mechanical cooling (air conditioning), which increases load and the emissions associated with serving that load.[98] Water conditions can change hydroelectric power availability, with low water years increasing reliance on GHG emitting generation. An increase or decrease in macroeconomic activity can alter energy demand and the emissions associated with serving load. **Figure 25** demonstrates the non-linear pattern of year-to-year reported emissions, with a declining trend from 2010 through 2022. Due to these annual

[97] ORS 468A.280, available at: https://www.oregonlegislature.gov/bills_laws/ors/ors468a.html
[98] Since non-emitting resources dispatch first, an increase in load above the expected basis would likely be met by gas, coal or market purchases.

GHG variations, the Public Utility Commission of Oregon (OPUC or the Commission) has stated that utilities should "achieve the 2030 and 2035 clean energy targets under typical or expected weather and hydro conditions…".[99] More discussion and analysis on how temperature and hydropower conditions impact GHG emissions is in **Appendix I, C-level analysis**.

Because of the correlation between load and emissions, GHG emissions intensity, defined as metric tons of CO2e per megawatt hour (MWh), is a useful decarbonization metric as it normalizes changes in load to better account for the resource mix that is serving that load. **Figure 26** shows PGE's Oregon retail GHG intensity from year 2010 through 2022. While GHG intensity provides useful information, HB 2021 requires an absolute reduction in utility GHG emissions, not a decrease in GHG intensity.

Figure 26. Historical GHG intensity for Oregon retail load service

HB 2021 does not explicitly set GHG limits for years prior to 2030. ORS 469A.415 (4)(e) states that electric utilities, like PGE, must demonstrate continual progress towards meeting clean energy targets in a Clean Energy Plan (see **Chapter 1, Clean energy plan**). HB 2021 did not define progress as actual annual emissions reductions. PGE believes that demonstrating continual progress includes planned annual actions to procure non-emitting resources to transition away from fossil fuel resources at a pace to reduce emissions to the targets in 2030, 2035 and 2040. The Clean Energy Plan (CEP) will detail actions sufficient to reduce emissions

[99] *In the Matter of Public Utility Commission of Oregon, House Bill 2021 Investigation into Clean Energy Plans*, Docket No. UM 2225, Order No. 22-446 (Nov 14, 2022), Appendix A at 31, available at: https://apps.puc.state.or.us/orders/2022ords/22-446.pdf

to at or below required thresholds under typical conditions. To examine the optimal progress toward 2030 GHG targets in portfolio analysis, PGE employs various GHG glidepaths to arrive at the HB 2021 targets. See **Section 11.4.1, Decarbonization glidepath portfolios,** for more detail.

The IRP assumes future load growth after cost-effective energy efficiency and distributed energy resources (DERs) are acquired and incorporated into PGE's system. Therefore, emissions reductions occur due to non-emitting resource procurement displacing coal or gas generation (as opposed to reductions from net demand reduction). In actual reporting, there will likely be a non-linear GHG decline due to various factors, including but not limited to:

- Weather variations: for example, the same power system will produce different emission levels in a mild temperature year vs. an extreme temperature year.[100] This is discussed by the OPUC in Order 22-446 and is further explored in **Appendix I, C-level analysis**.[101]
- Procurement timelines: GHG emissions decline when PGE acquires additional non-emitting energy. These acquisitions will occur in blocks and may lead to a staircase-like GHG reduction pathway. However, while each portion of resource procurement may lead to a 'blocky' reduction of GHG emissions, from a portfolio perspective, balancing regulatory, operational, financial and resource procurement risks point to the advantages of continual acquisition of non-emitting resources rather than delaying acquisition until just before the 2030 compliance window. Achieving a continual reduction pathway will necessitate procurement of non-emitting resources throughout the decade, which is likely to provide the best opportunity to add resources that offer an optimal combination of geographic location, resource characteristics, technological advancements and access to needed transmission rights.
- Unexpected economic conditions impacting loads: higher or lower than expected load may impact GHG emissions. Higher loads could arrive from faster-than-expected industrial growth (potentially from data centers) and/or faster-than-expected electrification.

5.2 Annual ODEQ reporting process

The HB 2021 GHG targets applicable to PGE include an 80 percent below baseline emissions level by 2030, a 90 percent below baseline emissions level by 2035 and 100 percent below baseline emissions level by 2040. ODEQ determines the baseline period for the investor-owned utilities as the average annual GHG emissions for 2010, 2011 and 2012 associated

[100] See **Section 6.1, Load forecast**, for more discussion on extreme temperature events.
[101] *In the Matter of Public Utility Commission of Oregon, House Bill 2021 Investigation into Clean Energy Plans*, Docket No. UM 2225, Order No. 22-446 (Nov 14, 2022), Appendix A at 13-14, available at: https://apps.puc.state.or.us/orders/2022ords/22-446.pdf

with the electricity sold to retail electricity consumers in Oregon as reported to the Oregon Department of Environmental Quality (ODEQ).

Regulated entities will continue to report annual GHG emissions to ODEQ, as they do today. In compliance years 2030, 2035 and 2040 and every year thereafter, the OPUC will use the data reported to ODEQ for that compliance year to determine whether the emissions targets are met.

Per the ODEQ's instructions for reporting greenhouse gas emissions, "Investor-owned utilities and electricity service suppliers must report their greenhouse gas emissions resulting from electricity served to end-users in Oregon to ODEQ, as prescribed by OAR 340-215-0120."[102]

As PGE's service area is only within the State of Oregon and PGE is not an "asset-controlling supplier" (as defined in the rule), PGE reports emissions following the non-multijurisdictional investor-owned utility methodology. This reporting must reflect emissions from the previous calendar year (Jan. 1 to Dec. 31) and be submitted to the ODEQ by June 1 of the following year. PGE is required to report the MWh of electricity generated or purchased to serve end users in Oregon for the previous emissions year for both unspecified and specified power sources.

From the total MWh of electricity generated or purchased to serve end users in Oregon, PGE then adjusts its reporting for sales to the wholesale markets, as prescribed by OAR 340-215-0120 (1)(d), "For electricity suppliers that are not multi-jurisdictional utilities, proportionally adjust all resources on an annual basis to account for the sale of power to the wholesale market that is not known to be just specified or unspecified."[103] PGE specifically adjusts certain resources for specified sales to the wholesale market for:

- Colstrip sales that are not wheeled into PGE's system and do not serve Oregon retail customers,
- Sales that are generated at a PGE-owned facility and delivered into the energy imbalance market (EIM), and
- Specified sales to California.

The remaining amount of wholesale sales is not known to be just specified or unspecified. As such, PGE proportionally adjusts all resources annually to account for the remaining sale of power to the wholesale market, as required by OAR 340-215-0120 (1)(d).

[102] ODEQ's instructions for reporting greenhouse gas emissions, available at: https://www.oregon.gov/deq/aq/Documents/GHGRP-IOUESSProtocol(non-MJ).pdf
[103] OAR 340-215-0120 (1)(d), available at: https://secure.sos.state.or.us/oard/viewSingleRule.action?ruleVrsnRsn=269300

5.2.1 Specified sources

A "Specified source of electricity" means a facility or unit allowed to be claimed as the source of electricity delivered.[104] PGE is required to report power as generated from a specified source when PGE is (1) a full or partial owner or operator of the generating facility or unit or (2) party to a power contract for a fixed percentage of generation from the facility or unit, or (3) party to a tolling agreement and rents a facility or unit from the owner, or is an exclusive power deliverer that is not a retail provider and that has prevailing rights to claim electricity from the specified source.[105] PGE is required to report power as purchased from a specified source when PGE can provide documentation that a power contract designated purchases from a specific generation power facility, unit or ODEQ-approved asset controlling supplier (ACS) at the time the transaction was executed.[106]

Per the ODEQ's instructions for reporting greenhouse gas emissions, reporting requirements for specified power include:

> *"If power is purchased or generated from specified sources, report the MWh of electricity disaggregated by facility or unit, and by fuel type or ACS, as measured at the busbar. Utilities must use a 2 percent transmission loss correction factor when reporting electricity not measured at the busbar of the generating facility.*
>
> *Annually, ODEQ will assign facility-specific or unit-specific emission factors for all registered specified sources by dividing the emissions (Metric tons of CO2 equivalent) by the net generation (MWh) from a specified facility or unit for the most recent year data is available.*
>
> *Emissions from specified sources are calculated by multiplying the MWh served to end users in Oregon by the ODEQ assigned facility or unit specific emission factor, and by transmission loss factor, where applicable."*[107]

[104] See Greenhouse Gas Reporting Protocols at: https://www.oregon.gov/deq/aq/Documents/GHGRP-IOUESSProtocol(non-MJ).pdf
[105] *Id.*
[106] *Id.*
[107] *Id.*

5.2.2 Unspecified sources

An "Unspecified source of electricity" means a source of electricity that is not a specified source at the time of entry into the transaction to procure the electricity. [108] Unspecified sources of electricity in PGE's system typically come from short-term market purchases, including the EIM. Currently, all unspecified market purchases receive the ODEQ-specified rate of 0.428 metric tons per MWh.[109] This rate is determined by ODEQ and is not updated at regular intervals. As a result, it may result in certain MWh receiving a higher CO2e intensity compared to the actual CO2e intensity of unspecified market purchases.

Per the ODEQ's instructions for reporting greenhouse gas emissions, reporting requirements for unspecified power include:

> *"Utilities must report the MWh provided to end users in Oregon from any unspecified power source.*
>
> *Electricity imported, sold, allocated or distributed to end users in this state through an EIM or other centralized market administered by a market operator is considered to be an unspecified source. Separately identify the MWh for power purchased from these markets from other unspecified sources.*
>
> *The default emission factor for calculating emissions from unspecified power is 0.428 MT CO2e/MWh.*
>
> *Emissions from unspecified sources are calculated by multiplying the MWh served to end users in Oregon by the default emission factor for unspecified power, and by the transmission loss factor, where applicable."*

5.2.3 Third-party verification of annual emissions

Beginning in 2021, ODEQ requires annual reporting of GHG emissions to be verified by a third party.[110] Third-party verifiers must be certified by ODEQ, and use of the same verifier for more than three consecutive years is prohibited. The annual deadline for verification is September 30th. PGE received a positive verification statement by the deadline of September 30, 2022, for the 2021 annual ODEQ Investor-Owned Utility emissions reporting.

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[108] *Id.*
[109] See OAR 340-215-0120, available at: https://secure.sos.state.or.us/oard/viewSingleRule.action?ruleVrsnRsn=269300
[110] See Greenhouse Gas Reporting Protocols, available at: https://www.oregon.gov/deq/aq/Documents/GHGRP-IOUESSProtocol(non-MJ).pdf

5.3 Components of IRP emissions reporting

Emissions flow through the IRP in three main steps. First, the PGE-Zone Model (PZM, conducted in Aurora) estimates the economic dispatch of all dispatchable resources, including the existing GHG-emitting resources. More information on economic dispatch and the PZM model is in **Appendix H, 2023 IRP modeling details**. Second, these data and historical GHG emitting market and contract purchases are input into the Intermediary GHG model. This model, described in the following section, estimates how much energy from GHG emitting sources is retained for serving retail load and how much is sold on the wholesale market. This information determines the yearly energy position used by the capacity expansion model (ROSE-E) that creates new resource portfolios. More information on the energy load resource balance is in **Section 6.5.1, Energy-load resource balance**, and **Appendix F, Load resource balance**.

5.3.1 Intermediary GHG model

The Intermediary GHG model inputs data from the PZM simulation, historical market transactions and GHG intensity values from the ODEQ to allocate GHG emitting generation between serving Oregon retail load and wholesale market sales. As discussed in **Chapter 4, Futures and uncertainties**, PGE creates 39 forecasts of electricity prices using a Western Interconnection simulation and then dispatches PGE owned/contracted generation against those prices.[111] This results in 39 forecasts of total power plant utilization. The 39 resource-level generation forecasts feed into the Intermediary GHG model.

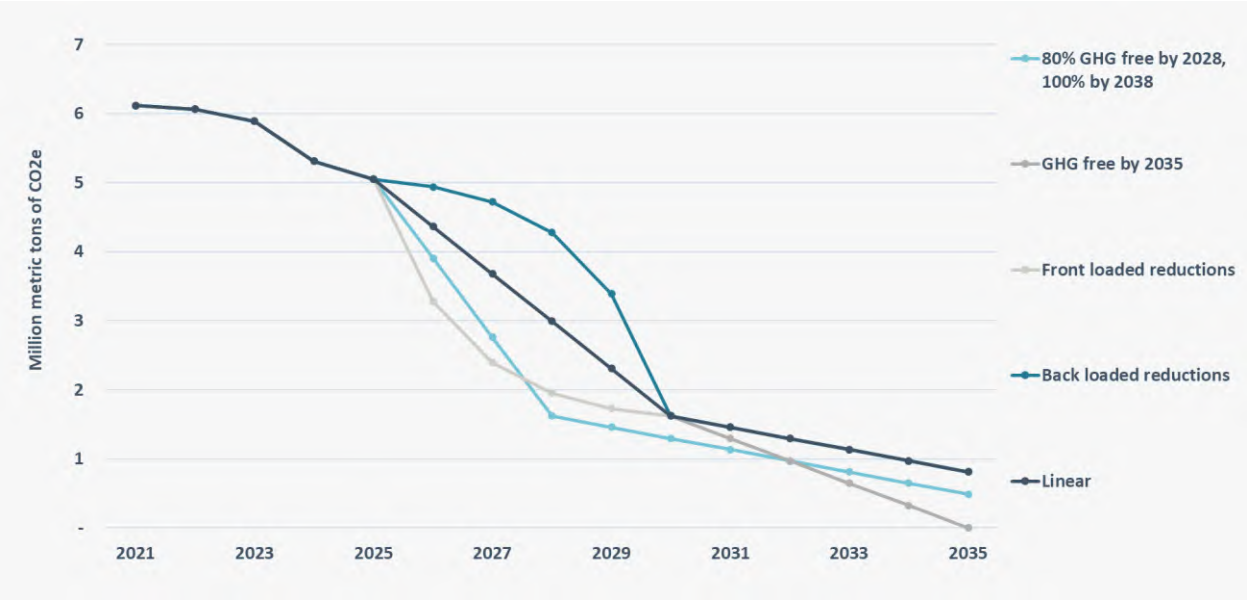
The PZM simulation forecasts total resource generation but does not distinguish between generation associated with retail load (regulated under HB 2021) and wholesale sales (not regulated under HB 2021). ROSE-E, the capacity expansion model, requires the amount of retail energy associated with GHG emissions as an input.[112] To bridge the gap between the PZM simulation and ROSE-E, the Intermediary GHG model performs two primary functions:

[111] The WECC-wide simulation simulates the power system through the end of the IRP planning horizon and takes Western carbon policies into consideration. These polices include carbon pricing, like in California and Washington, and decarbonization targets like Oregon's HB 2021. In aggregate, decarbonization policies add roughly 180,000 MW of solar, 70,000 MW of wind and 70,000 MW of storage to the Western Interconnection model from 2022 through 2045. PGE purchases the WECC-wide resource build database from Wood Mackenzie. More information on the resource buildout is in **Appendix H, 2023 IRP modeling details**.

[112] If instead the total existing thermal generation were used as an input by ROSE-E, the energy position would have an inappropriate amount of energy. This would lead to fewer non-emitting resources being built and the emissions targets would not be met on a planning basis.

1. Incorporates a GHG emission reduction glidepath to HB 2021 targets in 2030, 2035 and 2040: The GHG glidepaths for the 2023 IRP are in **Figure 27**. They are a linear reduction glidepath, a glidepath where emissions reductions until 2030 occur more rapidly (front loaded), another where reductions until 2030 occur less rapidly (back loaded) and two glidepaths with accelerated targets (non-emitting by 2035 and meeting HB 2021 targets two years faster).[113] Using these glidepaths, the Intermediary GHG model determines the amount of GHG emitting generation that PGE can retain to serve retail load.

Figure 27. GHG glidepaths associated with serving Oregon retail load in the 2023 IRP



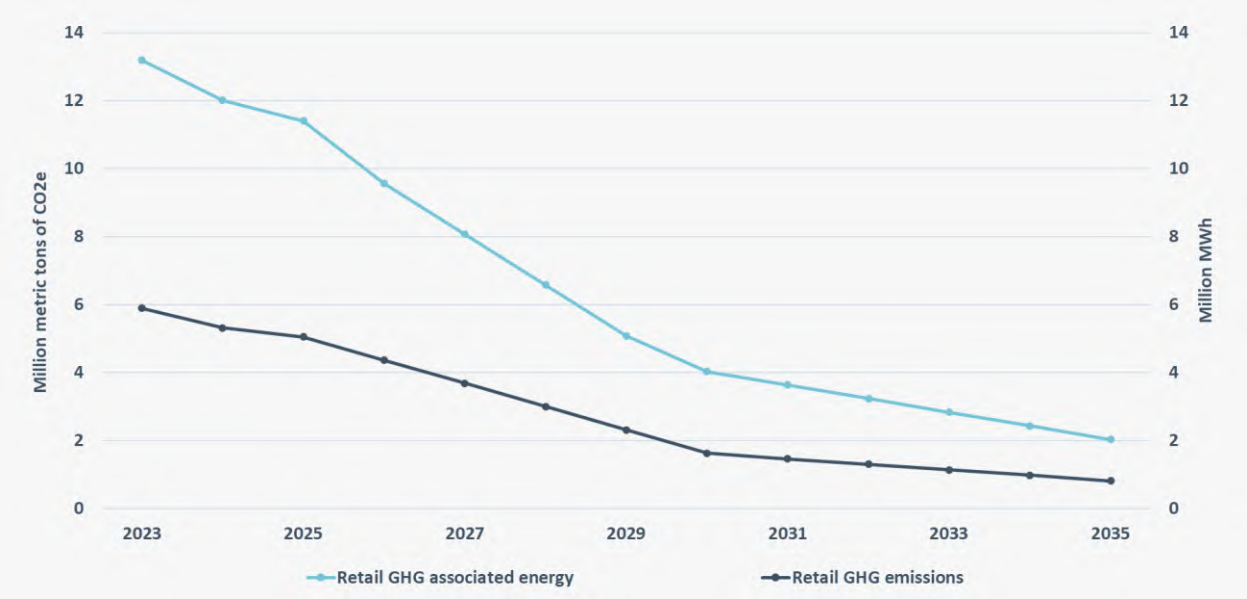
2. Incorporates an estimate of wholesale market transactions: PGE buys and sells power on the wholesale market for various reasons, including risk mitigation and net variable power cost reduction. The Intermediary GHG model estimates the size of market purchases based on historical data while considering the emissions associated with purchases. It also assumes that power not retained for retail load service sells into the wholesale market.

   The primary output of the GHG Intermediary model is an estimate of the energy from GHG emitting sources that PGE can use to meet retail load while meeting the GHG targets. This estimate flows into the energy load resource balance (**Section 6.5.1, Energy-load resource balance**) that is used as an input to the capacity expansion model (ROSE-E). An example of this output is in **Figure 28**, using the Reference Case price future and a linear GHG reduction glidepath. The lower line shows the GHG emissions

[113] With the front loaded-GHG pathway the amount of reduction from 2023 to 2030 half every year, in the back loaded-GHG pathway they double every year. All other pathways are linear to their respective targets.

associated with serving Oregon retail load, and the upper line is the corresponding GHG emitting energy retained for the retail load.

Figure 28. GHG emissions and energy associated with serving Oregon retail load (Reference Case)



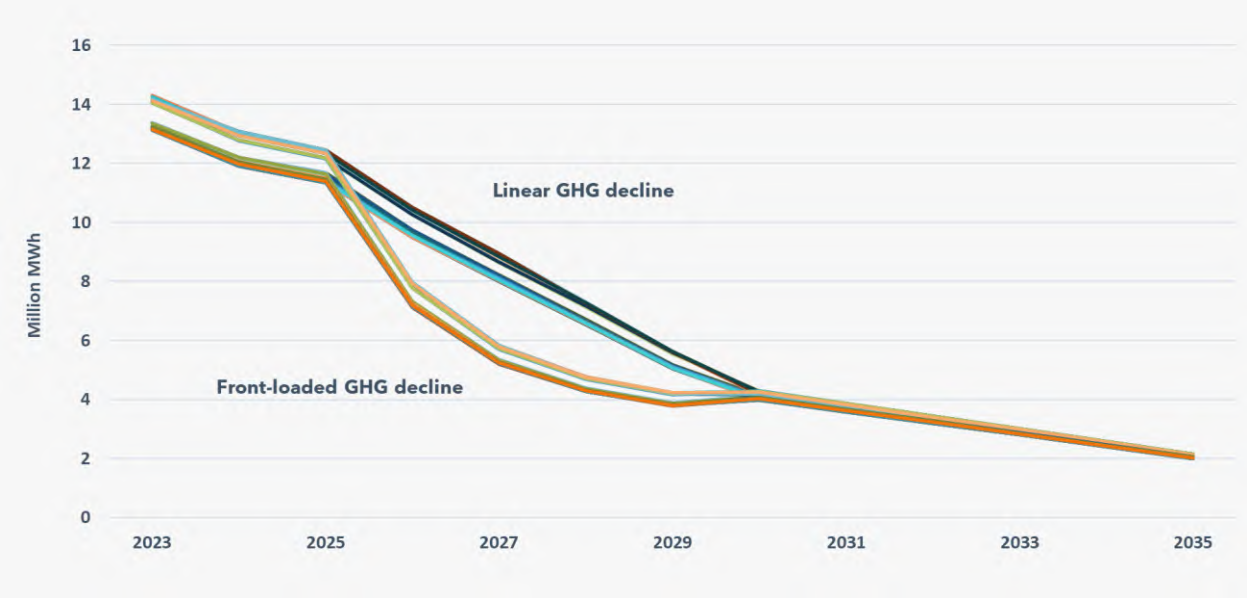
Other than Colstrip, most GHG-emitting energy in the PGE portfolio has a GHG intensity rate of around 0.37 to 0.43 MTCO2e/MWh (Colstrip is 1.00 MTCO2e/MWh).[114] Gas plants dispatch in order of economic efficiency, with the lowest emitting and most efficient plants usually operating at the highest capacity factors. As a result, unit dispatch generally plays a small role in determining how much energy from GHG emitting generation PGE can retain for retail load. For example, in 2030, retail GHG emissions must be 1.62 million metric tons or fewer. If PGE were to obtain all its GHG-related generation from unspecified market purchases with an intensity rate of 0.428 MTCO2e/MWh, it would result in 3.79 million MWh of generation. If PGE were to obtain all its GHG-related generation from Carty Power Plant with an intensity rate of 0.389 MTCO2e/MWh, it would result in 4.16 million MWh of generation, a relatively small difference of 0.37 million MWh (42-megawatt average (MWa)).

The difference in GHG emitting energy retained for Oregon retail load by price future (which impacts dispatch) is shown in **Figure 29**. It shows multiple price future outcomes under the linear glidepath and the front-loaded glidepath. While there are large energy differences

[114] Power Plants Beaver & Port Westward II, as well as some specified market purchases, have higher emissions rates in some years, but annual energy from these sources is typically low. BPA power has a much lower rate (0.013 MTCO2e/MWh as provided by DEQ for use in the CEP/IRP), but the variation of BPA power used for retail load is somewhat small across price futures.

between the two glidepaths, within the individual glidepaths, the energy differences are relatively small.

Figure 29. GHG emitting energy from serving Oregon retail load under different glidepaths and price futures



Beyond Oregon retail emissions, the GHG Intermediary model also calculates emissions and the associated energy from wholesale activities. The bulk of this estimate comes from the PZM simulation, which forecasts the generation levels of the major PGE thermal units and the GHG glidepath, a key input into how much energy is kept for Oregon retail load service.[115] In the PZM simulation thermal units economically dispatch against Western power prices. The prices are created taking carbon pricing and GHG reduction policies into consideration. For example, the PZM simulation includes carbon pricing in California and Washington and adds non-emitting resources to the West to meet emissions targets. Actual wholesale emissions will differ depending on the western resource buildout and future electric power policies.

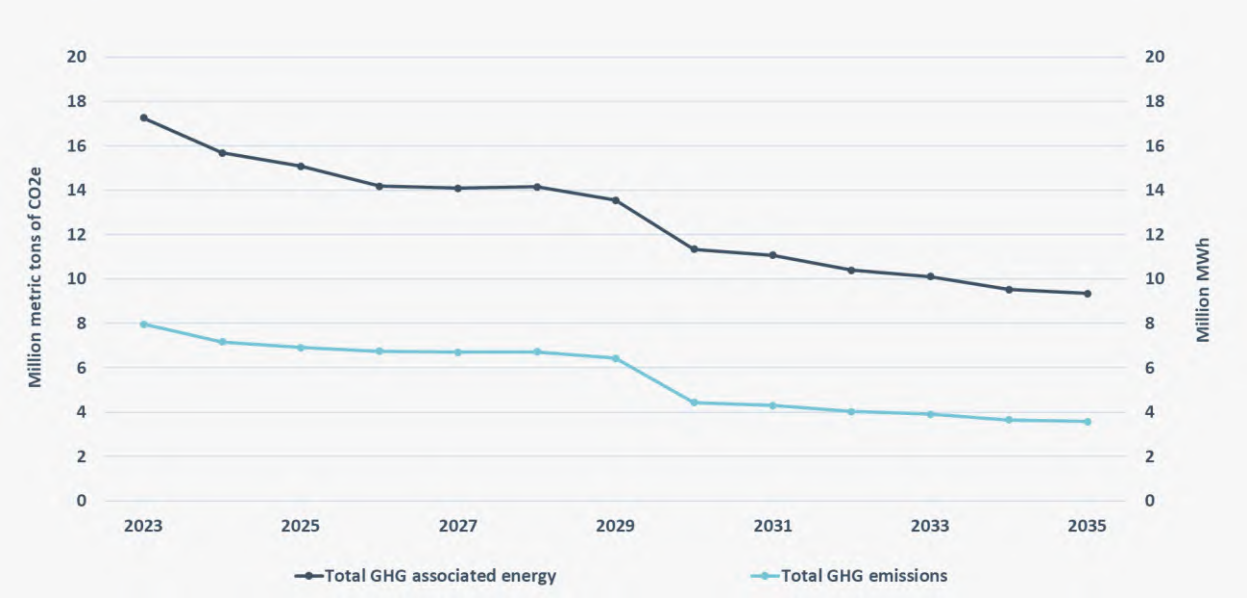
Economic dispatch also assumes an efficient dispatch order across the Western Interconnection. Operating gas plants less than economic dispatch may increase GHG emissions. For example, if the Carty power plant ran below economic dispatch, it would generate less energy. A less efficient gas plant elsewhere in the West would likely operate more to make up for this shortfall. The less efficient plant would emit more CO2e than Carty for each MWh of power produced, increasing GHG emissions across the West. This scenario would likely also increase PGE net-variable-power-costs if it reduced total wholesale

[115] These units are power plants Beaver, Carty, Colstrip (20 percent ownership), Coyote, Port Westward 1, & Port Westward 2.

transactions. Additional information on economic dispatch and the PZM simulation is in **Appendix H, 2023 IRP modeling details**.

Beyond PGE thermal units, the Intermediary GHG model adds additional energy and associated emissions with select contracts and wholesale market transactions. The total system (retail and wholesale) GHG emissions and associated energy from the Reference Case future is in **Figure 30**. More information on GHG-emitting resources (including requirements established in UM 2225) is in **Appendix O, Thermal Operations/ Output**.

Figure 30. Total GHG emissions and associated energy forecast



The Intermediary GHG model also passes to ROSE-E energy values from GHG-emitting resources. It does this using the retail and wholesale energy generation values in conjunction with annual forecasted power prices. The model is essentially a data pass-through from the PZM simulation to ROSE-E for this function.

5.3.2 ODEQ review of PGE forecasted emissions accounting

PGE will provide information to ODEQ to allow for a review of PGE's forecasted emissions accounting methodology as reported in this Clean Energy Plan. This will enable ODEQ to determine that emissions have been forecasted in alignment with ODEQ Greenhouse Gas Reporting protocols.

In forecasting emissions associated with portfolios, PGE will use ODEQ's emission factors for each existing GHG-emitting resource, and PGE will provide the associated forecast of the retail load generation of each plant, purchases and power sales by technology type for each year being forecasted.

Chapter 6. Resource needs

This chapter quantifies the drivers of system demand and their impact on energy, capacity and system flexibility need. Estimating these values is the first critical step in ensuring resource actions result in an adequate system that meets decarbonization and other policy objectives while minimizing long-term costs and risks.

Chapter highlights

- Load growth, expiring non-GHG emitting resource contracts and decreasing retail sales from existing thermal resources drive the need for more non-GHG emitting resources through the planning horizon.
- The load forecast has increased since the 2019 Integrated Resource Plan (IRP) Update due primarily to higher industrial load growth projections. In addition, the persistent impacts of COVID-19 have increased residential usage.
- Distributed energy resources (DERs), including transportation and building electrification, are having a more significant impact on total Portland General Electric (PGE) loads as compared to past IRPs.
- Capacity needs step upwards in 2026 and grow through the planning horizon due to expiring contracts, exiting resources and load growth. In the Reference Case, the 2028 capacity need is 624 megawatts (MW) in the summer and 614 MW in the winter.
- Flexibility needs in 2026 are estimated at 80 MW in the Reference Case, growing to 122 MW in 2030.
- Although capacity needs increase in both summer and winter throughout the planning horizon, climate change drives relatively more need in the summer and less need in the winter.

6.1 Load forecast

PGE's estimated demand for electricity is called its 'load forecast.'[116] Our load forecast has been influenced by rapidly evolving trends (such as those related to COVID-19 or extreme temperatures) and the slower-moving, longer-term trends in energy deliveries. Each is accounted for in different ways. The primary components of PGE's load forecast are:

- Top-down econometric load forecast: This model comprises two segments that capture business cycle impacts and long-term trends. **Section 6.1.1, Top-down econometric load forecasting**, describes the top-down econometric forecast mode and **Section 6.1.2, Load trends**, describes current load trends.[117]
- Incremental impacts associated with passive DERs: The impact of nascent and rapidly evolving end uses, including transportation electrification, rooftop solar and building electrification, is forecasted in PGE's Distribution System Planning process. The load impacts of DERs are accounted for in **Section 6.2, Distributed Energy Resource (DER) impact on load**.

6.1.1 Top-down econometric load forecasting

PGE's top-down forecasting models take an econometric approach by estimating the relationships between PGE service area historical load and exogenous drivers. These exogenous drivers include seasonal and weather variables and macroeconomic indicators (population, employment and income) used to describe regional economic trends.

Weather, specifically ambient temperature, is the most significant factor affecting customer electricity demand. PGE uses several weather variables in its energy and peak models, including heating and cooling degree days and wind speed. Energy use is also correlated with economic activity. PGE's econometric models forecast monthly energy deliveries by customer class and peak demand for the total PGE system. The primary model inputs are weather, population, employment, income, customer counts and historical loads. **Appendix**

[116] The Corporate Load Forecast is described in Section 3.3 of PGE's DSP, available at: https://assets.ctfassets.net/416ywc1laqmd/46I2n65SyTv3TUMMdq1I55/a993aebb7b7a84ebd3209d798454a33a/DSP_Part_2_-_Chapter03.pdf

[117] *In the Matter of Portland General Electric Company, 2019 Integrated Resource Plan*, Docket No. LC 73, Order No. 21-129 (May 3, 2021), Appendix A at 5 states: "Staff concurs with CUB that the impact of large customers in the industrial load forecast should be closely monitored. Staff supports PGE's plan on page 8 of its Reply Comments to 'review… peer electric utility industrial load forecasts and… summarize findings in an IRP roundtable participant discussion during the next IRP.'" PGE presented results of its benchmarking of economic drivers used in peer regional electric utilities' industrial load forecasts and performance of a broad range of economic drivers in PGE's industrial load forecast model at the July 22, 2021, public roundtable meeting to meet this commitment. Available at: https://apps.puc.state.or.us/orders/2021ords/21-129.pdf

H, 2023 IRP modeling details, provides additional details on the models that constitute this IRP top-down forecast and how those models were tested and selected.

Econometric models assume that certain structural relationships captured represent the future. In addition, PGE's Reference Case load forecast incorporates several key model input assumptions:

- **COVID Recovery:** An indicator variable is used in PGEs models to capture the impact of COVID-19 on energy deliveries. The input assumption for this variable implies how those impacts taper during the forecast period. While we expect this input to continue to evolve to reflect current expectations, this IRP forecast assumes the long-term equilibrium for residential customers was reached in mid-2022. This level is estimated to be approximately 30 percent of the impact seen in the early months of the COVID-19 lockdowns.
- **Weather:** PGE's load forecasts reflect normal or expected weather conditions throughout each year. For this IRP, the expected weather conditions are represented by a trended model for heating and cooling degree days to reflect the gradually warming regional climate. The forecasts do not attempt to predict, for example, an El Niño winter, a particularly hot summer or any weather event in any given year. A discussion of additional climate analysis is included in **Section 6.9, Climate adaptation**.
- **Direct access:** Customers with approximately 270-megawatt average (MWa) of combined commercial and industrial load in PGE's service area have opted out of PGE's cost-of-service (COS) supply rates and receive energy from electricity service suppliers (ESS).[118] In IRP Guideline 9, in Order No. 07-002, the Commission prohibits the inclusion of long-term direct access customer loads in long-term planning for both energy and capacity needs.[119] This IRP portfolio analysis excludes these customer loads. However, as discussed in **Section 3.1.6, Local climate action planning** nine counties and cities served by PGE have already established climate-related goals through community processes and plans, and at least four more are in the process of developing plans. These plans typically cover a variety of goals and objectives, including those concerning greenhouse gases, energy use, transportation, waste, land use, health and safety, and economic development. **Table 5** captures a list of local governments with existing plans (or in some phase of developing one) and some key electricity and emissions goals.

Several cities and counties have timelines for their decarbonization goals that align with our HB 2021 targets. For those local governments that want to decarbonize on a faster timeline, PGE's Green Future Enterprise and Green Future Impact are being used to support clean

[118] This includes 1-year direct access (STDA), long-term direct access (LTDA) and new load direct access (NLDA) schedules.
[119] *In the Matter of Public Utility Commission of Oregon, Investigation Into Integrated Resource Planning*, Docket No. UM 1056, Order No. 07-002 (Jan 8, 2007) at 19, available at: https://apps.puc.state.or.us/orders/2007ords/07-002.pdf

energy goals. Many of our large commercial and industrial customers also use these and other programs to meet their decarbonization goals.

PGE has been working with local governments since 2020 to develop a community-supported renewable program to support those local governments that have adopted community-wide climate goals. During the 2021 legislative session, PGE worked in partnership with several of our local governments to pass language within HB 2021. The program will allow local governments to work with PGE to accelerate the procurement of non-emitting energy to meet their climate goals. Since the bill's passage, PGE staff have been meeting regularly with local governments to solicit feedback on the design so that the program will meet their goals and desired approach. As PGE continues to engage with local governments, collectively we will determine the right time to file the tariff to support the program.

- Regulatory policy: Direct access, this interpretation presents reliability and cost risks to cost-of-service supply customers. Consistent with prior IRPs, PGE includes one-year direct access customers in its IRP planning because they may return to PGE's COS rates with little notice.

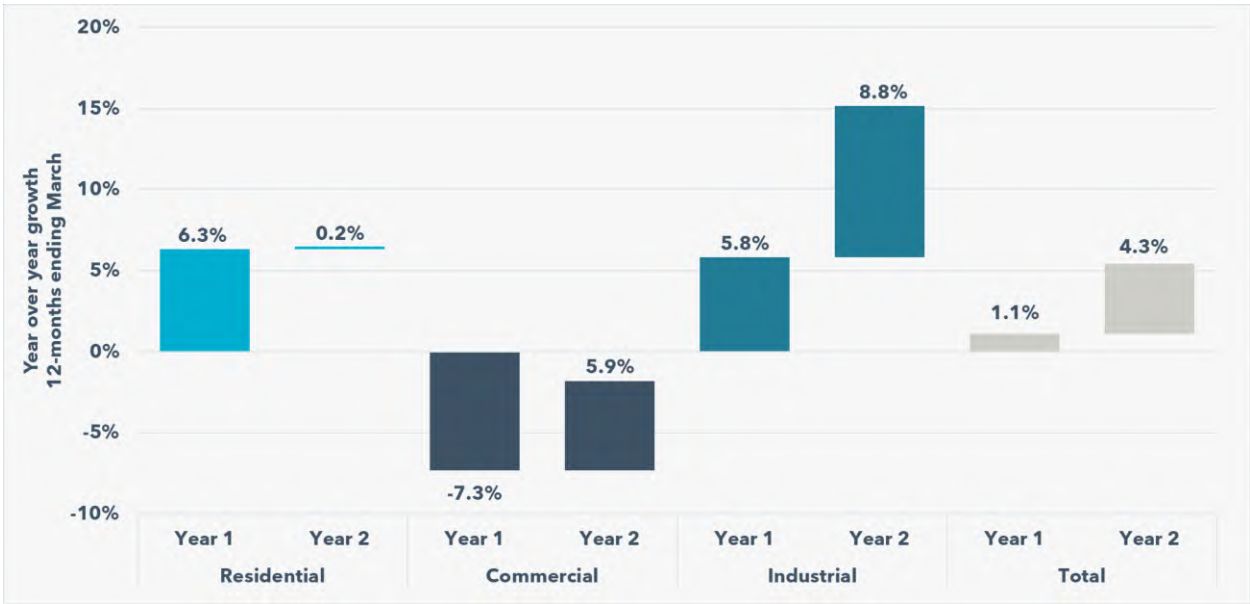
6.1.2 Load trends

6.1.2.1 Impact of COVID-19

Recent load trends (marked by the impact of COVID-19) have influenced how PGE's customers use electricity. The prevalence of work-from-home policies increased average residential usage, which remains high. As these changes to remote work will persist, we believe the impact of the last two years marks a longstanding change in average residential usage. In the commercial segment, initial shutdowns had a stark but short-lived impact on energy deliveries. We believe prior structural relationships, including long-term trends and relationships to macroeconomic indicators, hold true. PGE's industrial segment was impacted least by COVID-19 and has grown since the 2019 IRP.[120] **Figure 31** depicts changes in usage between customer classes since the March 2020 lockdowns.

[120] *In the Matter of Portland General Electric Company, 2019 Integrated Resource Plan*, Docket No. LC 73, filed July 19, 2019.

Figure 31. PGE's annual energy deliveries growth since the initial COVID-19 lockdown



Given the limited duration since the onset of COVID-19, PGE used out-of-model forecast adjustments to account for COVID-19 in its 2019 IRP Update load forecast.[121] Since the 2019 IRP Update load forecast was finalized, PGE developed a methodology to account for COVID-19 in its econometric models by using indicator variables to reflect various stages of closure and recovery. This method applies to most, but not all, of PGE's forecast segments and is discussed in further detail in **Appendix D, Load forecast methodology**. The evolution of the modeling approach was shared with stakeholders in IRP Roundtables, first on October 28, 2020, when out-of-model adjustments were used as a temporary approach, and then on July 22, 2021, where the indicator variable approach was presented.

6.1.2.2 Industrial growth

Energy deliveries to PGE's industrial segment have increased rapidly over the past few years. Industrial growth has been focused on the semiconductor manufacturing and data center segments. The construction of new customer facilities continues at a rapid pace as discussed in **Chapter 3, Planning environment**.

With respect to electric load, the number of projects and the average project size assessing sites in PGE's service area for new data center projects have increased. Additional projects may see investment opportunities associated with CHIPS and Science Act funding in coming years. The realization and timing of large projects present heightened uncertainty around

[121] Docket No. LC 73, PGE's Integrated Resource Plan Update, filed January 29, 2021.

PGE's load forecast. However, the rate at which the industrial sector incorporates energy efficiency also presents uncertainty in demand.[122]

6.1.2.3 Severe temperature

Since the 2019 IRP, PGE's service area experienced an unprecedented maximum temperature event, the "heat dome" of June 2021, and the warmest month on record in August 2022 based on average temperature.[123] Concurrent with these events came unprecedented hourly peak demands. PGE's net system peak on June 28, 2021, set a new system record at 4,453 MW. During the summer of 2022, PGE's net system exceeded 4,000 MW - a load level not seen in over 10 years prior to 2021 - on nine different days, including reaching 4,100 on five consecutive days in late July. These events, coupled with more time spent in the home due to work-from-home policies and national macroeconomic trends of strong consumer expenditures on home upgrades, will likely continue the long-term trend of increasing saturation of air conditioning in PGE's service area. Air conditioner saturation is included in PGE's peak demand forecast. Several sector-level energy delivery models have been modified to account for this additional cooling demand.

In addition to extreme heat events, winter weather continues to be a significant driver of PGE's peak loads. On December 22, 2022, PGE's service area set a record for its winter season net system peak at 4,113 MW. This event occurred during severe weather, with a daily average temperature of 23 degrees Fahrenheit at Portland International Airport and surpasses PGE's prior winter system peak set in 1998. This event highlights that while PGE has transitioned towards a summer peaking service area, the regional climate still faces the challenges of planning for a dual peaking system.[124]

6.1.3 Load uncertainty

All forecasts have inherent uncertainty. For example, uncertainty is associated with the model input data, the selection of the model itself and the relationships established within it, and factors external to the model. To reflect uncertainty in the model input data and the

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[122] PGE and the ETO presented opportunities for energy efficiency at data centers at the February 2023 IRP roundtable; greater adoption by the industrial sector could mitigate demand growth.

[123] Mesh, Aaron. "August Was Portland's Hottest Month Ever: The key factor: warm nights." Willamette Week (Sept 2, 2022, 2:14 pm PDT), available at: https://www.wweek.com/news/environment/2022/09/02/august-was-portlands-hottest-month-ever/#:~:text=The%20key%20factor%3A%20warm%20nights.&text=This%20August%20was%20the%20hottest,record%3A%2074.1%20in%20July%201985. Accessed October 27, 2022.

[124] **Appendix I, C-level analysis**, provides discussion on how extreme temperature can impact system GHG emissions. These extreme weather trends were first discussed in the "Climate Change Projections in Portland General Electric Service Territory" that PGE commissioned Oregon State University's Oregon Climate Change Research Institute, Prepared by Meghan Dalton. The report is available in Docket No. LC 66, PGE's 2016 Integrated Resource Plan (filed Nov 15, 2016) at 391, available at: https://edocs.puc.state.or.us/efdocs/HAA/lc66haa144338.pdf

relationships estimated in the load forecast, PGE empirically develops high- and low-load growth scenarios. These scenarios focus on alternate futures for macroeconomic drivers and incorporate stochastic load risk analysis by adding or subtracting one standard deviation in model uncertainty. **Table 10** shows the inputs used to create the low, reference and high top-down load forecasts.

Table 10. Inputs to top-down econometric load forecast scenarios

Economic driver	Low load	Reference Case	High load
Population	0.0%	0.7%	1.5%
Employment	0.5%	1.3%	2.5%
Income	1.0%	2.1%	3.5%
Model uncertainty	-1 SD	None	+1 SD

Electrification is also a key area of load uncertainty. This is modeled outside PGE's top-down econometric forecast and discussed in **Section 6.2, Distributed Energy Resource (DER) impact on load**.

The resulting load scenarios are summarized in **Table 11**.

Table 11. Top-down econometric load forecast scenarios

	Low load	Reference Case	High load
Peak demand	0.4%	0.8%	1.1%
Total energy	0.5%	1.2%	1.7%
Residential	0.0%	0.5%	0.9%
Commercial	-0.4%	0.0%	0.3%
Industrial	2.3%	3.5%	4.3%

*Table reflects 20-year average annual growth rate for years 2023-2042, before the impacts of electrification, discussed in **Section 6.2, Distributed Energy Resource (DER) impact on load**.

6.2 Distributed Energy Resource (DER) impact on load

PGE's 2022 Distribution System Plan (DSP) Part 1 and 2 form the basis for DER actions within this IRP except for energy efficiency, which is sourced from Energy Trust of Oregon

(ETO).[125,126,127] The DSP leverages PGE's AdopDER model to perform bottom-up site-level adoption of over 60 DER technologies and technology combinations. The model accounts for key site-level factors such as access to garage parking, breaker space and equipment turnover to determine the technical, achievable and economic potential, as illustrated in **Figure 32**. The AdopDER model simulates the market adoption of passive DERs and the expected participation of customers in current and potential demand response programs. Within the DSP, we simulated the adoption across three scenarios with varying parameters such as cost and policy interpretation. Additional details on the DER forecast methodology, assumptions, and outputs can be found within the DSP filing. The Inflation Reduction Act (IRA) was signed into law after filing the DSP. Thus, its impact is not captured as it pertains to the market adoption of passive DERs such as rooftop solar, electric vehicles and building electrification. While this impact is not explicitly modeled, PGE has modeled both a high adoption case of these technologies and conducted a sensitivity to understanding how resource actions and system needs vary along the range of passive DER adoption. This is further described in **Section 4.2, Need** , and **Section 6.10.2, Accelerated load growth sensitivity**.

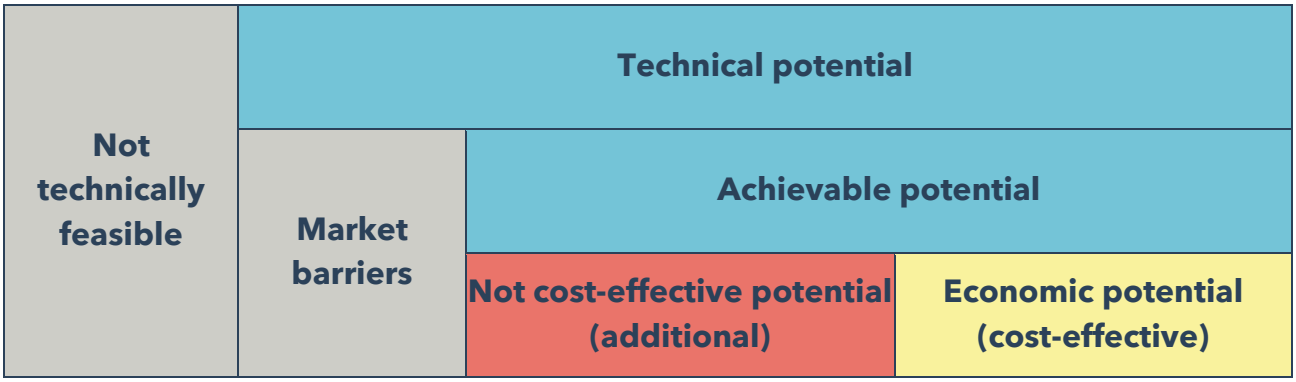
In this chapter, we first focus on the market adoption of passive DERs (rooftop solar, transportation electrification and building electrification). Then, we discuss the integration of cost-effective or economic potential of DR and EE through customer programs. The cost-effective potential is highlighted in yellow in **Figure 32**. The treatment of non-cost-effective or additional energy efficiency and demand response is described in **Section 8.2, Additional distributed energy resources**.

[125] PGE's DSP Part 1, available at: https://apps.puc.state.or.us/edockets/edocs.asp?FileType=HAA&FileName=um2197haa85326.pdf&DocketID=23043&numSequence=1

[126] PGE's DSP Part 2, available at: https://apps.puc.state.or.us/edockets/edocs.asp?FileType=HAD&FileName=um2197had151613.pdf&DocketID=23043&numSequence=21

[127] For the purposes of PGE's IRP, we utilize the OPUC's definition of DERs which includes distributed generation resources, distributed energy storage, demand response, energy efficiency and electric vehicles that are connected to the electric distribution power grid. See *In the Matter of Public Utility Commission of Oregon, Investigation Into Distribution System Planning*, Docket No. UM 2005, Order No. 20-485 (Dec 23, 2020), Appendix A at 15, fn. 2.

Figure 32. The different potential assessments of DERs

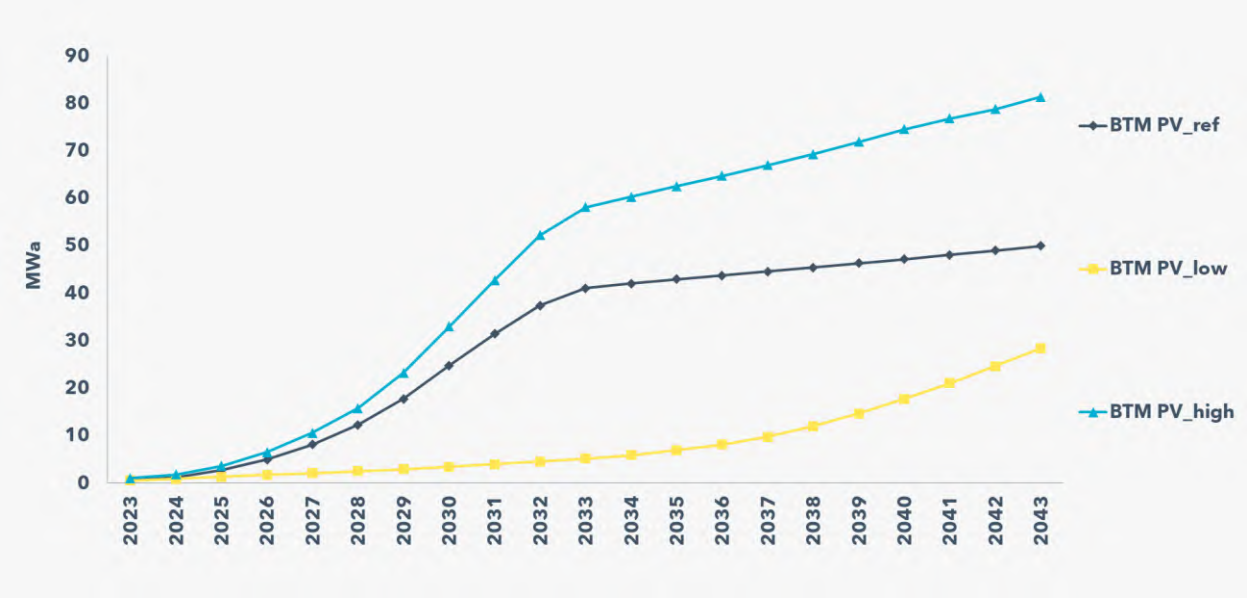


6.2.1 Passive DERs

Passive DERs are driven by direct customer adoption, such as distributed solar PV, electric vehicles and building electrification end uses. As identified in the DSP, distributed solar PV has a high technical potential of approximately seven gigawatts (GW) of nameplate capacity within the service area by 2050. Based on the adoption curves produced within the DSP, we expect annual customer adoption of solar to peak in the early 2030s because of declining solar PV costs, which will lead to favorable customer economics within the current policy environment. Thus, the incremental energy impact from 2023 of customer-adopted solar in the Reference Case is estimated at ~25MWa by 2030, as shown in **Figure 33**.[128] By the end of the planning horizon, this is expected to double. The incremental nature of **Figure 33** ensures that solar PV currently on the system is not double counted.[129] Residential customers drive the bulk of the solar adoption, given the economics between rates (Net Energy Metering (NEM) Incentives) and costs. However, NEM incentives do not require customers to comply with IEEE-1547, 2018 smart inverter standards. This prevents rooftop solar from being properly integrated and thus prevents PGE customers from realizing the full benefit of rooftop solar PV. Additionally, and especially with the IRA extending tax benefits on rooftop solar, the cost shift stemming from the current NEM policy will continue to increase inequities across customers and, consequently, energy burden, which was identified as a key measure by community partners in **Section 7.1.6, Informational community benefits indicators**.

[128] MWa and MW reporting of DERs may vary between the DSP and IRP, though the source data for the locational forecast is consistent between the DSP and IRP. The DSP outputs used for reporting purposes are simplified and do not account for intra-year ramping/adoption. IRP outputs shown here include intra-year ramping. This difference is larger in early years where intra-year ramping is significant and shrinks over time because each new year's incremental contribution decreases.
[129] In response to Docket LC 73, PGE 2019 Integrated Resource Plan, Order 20-152's requirement at 22, "In the next IRP, PGE is to report on trends of sales by customer class and DER installments for 2015 through 2019", PGE has provided this information within the DSP Part 1, Section 1.5 of Chapter 1, available at: https://assets.ctfassets.net/416ywc1laqmd/ELNdf17zyQvQiU9k71pIX/683cd2f7b3098517068c4594100a1025/DSP_2021_Report_Chapter1.pdf.

Figure 33. MWa generation impact of behind the meter (BTM) distributed solar PV over the planning horizon



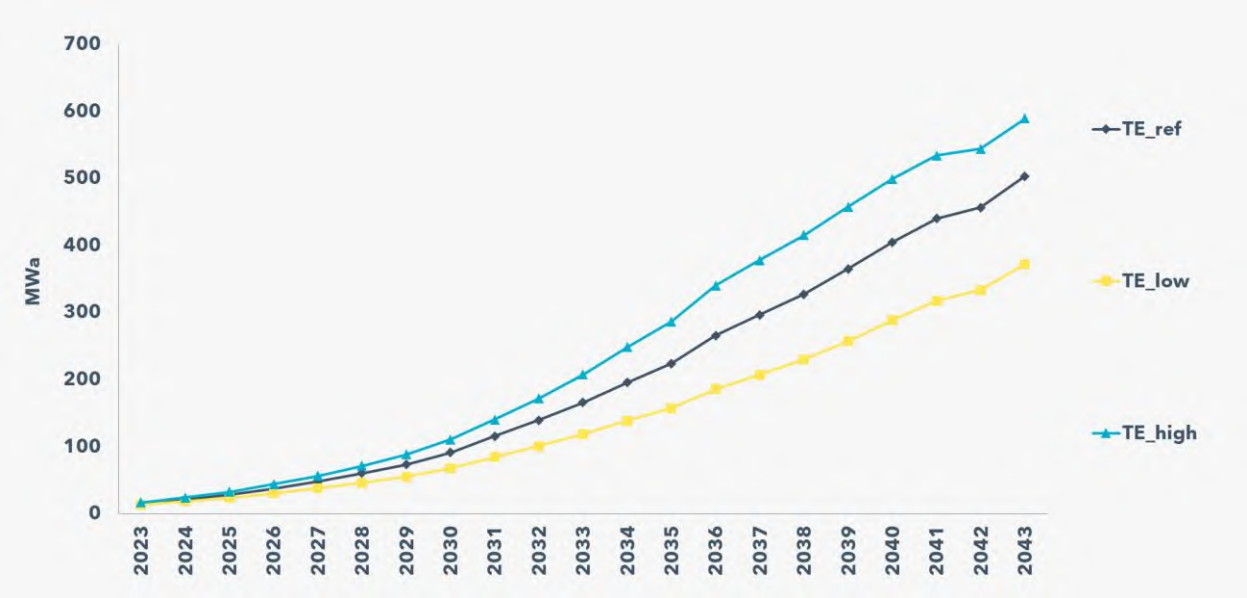
We forecast higher levels of adoption for electric vehicles than in the previous IRP, particularly in the light-duty segment. Based on the DSP, by 2030, we expect 341,280 light-duty electric vehicles on the road, with 298,244 vehicles in the residential sector and 9,817 medium and heavy-duty EVs in the Reference Case. Consequently, we expect the transportation electrification load to be ~91 MWa by 2030, with a fivefold increase by 2043 to ~503 MWa.

Policy assumptions in the DSP do not include the impact of the Advanced Clean Cars II rule passed on December 19, 2022, which requires auto manufacturers to deliver 100 percent new zero-emission battery electric and plug-in hybrid electric vehicles by 2035.[130] **Section 6.10.2, Accelerated load growth sensitivity**, details a demand growth sensitivity analysis that is more aggressive than the Advanced Clean Cars II rule.

Figure 34 represents the gross transportation electrification load across varying adoption scenarios, not accounting for the potential impact of associated demand response programs such as time-of-use or managed charging programs. These demand response programs are represented within the demand response potential in **Section 6.2.2, Demand response**.

[130] The Advanced Clean Cars II, Administrative Order No. DEQ-23-2022, effective 12/19/2022, available at: https://www.oregon.gov/deq/rulemaking/Documents/DEQ232022.pdf

Figure 34. MWa impact of transportation electrification (TE) over the planning horizon

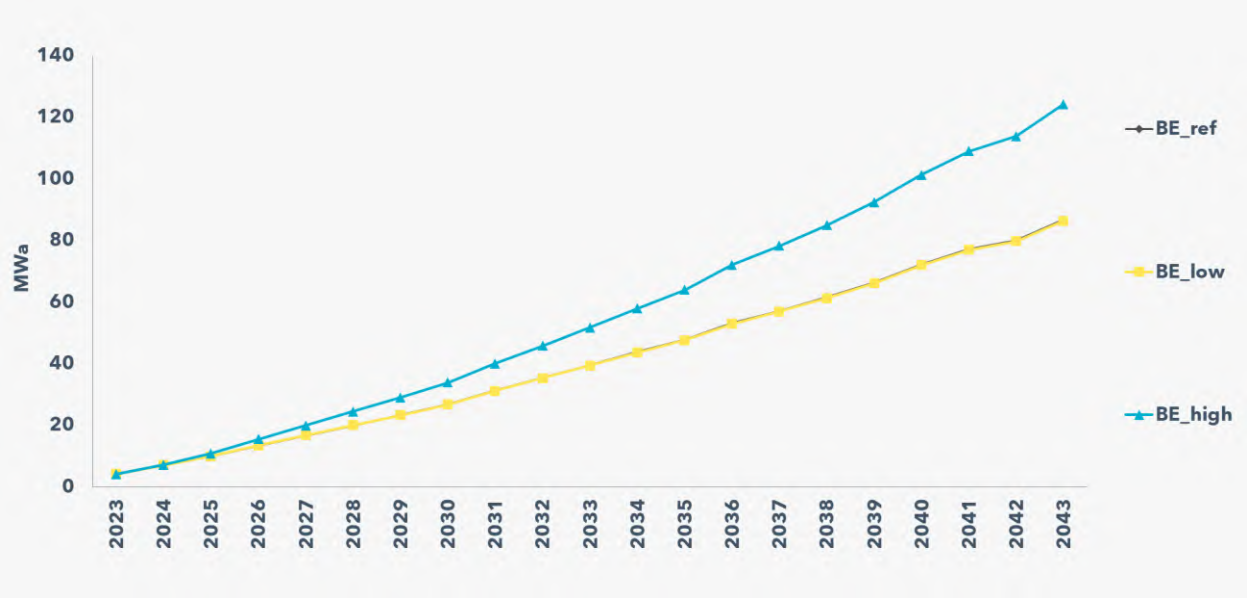


Building electrification has significant potential to decarbonize the economy further. The adoption of electric space heating, water heating and cooking technologies within the new construction sector and fuel switching within existing buildings drives the building electrification forecasts. For this IRP, we leveraged the DSP outputs and associated assumptions. By 2030, we expect a ~27MWa impact from building electrification. While this impact increases both summer and winter resource adequacy needs, the winter needs are impacted more prominently because of the space heating end use, which coincides with the winter peak.

Like transportation electrification, **Figure 35** represents the gross building electrification load across varying adoption scenarios, not accounting for the potential impact of associated demand response programs such as time-of-use or managed charging programs. These demand response programs are represented within the demand response potential in **Section 6.2.2, Demand response**.

In addition to the building electrification scenarios modeled in the DSP, we have also modeled an electrification sensitivity to understand the impact of electrification, assuming the Climate Protection Program's compliance is achieved only through increased electrification. This is further described in **Section 6.10.2, Accelerated load growth sensitivity**.

Figure 35. MWa impact of building electrification (BE) over the planning horizon



6.2.2 Demand response

As noted earlier in the section, the DSP informs DER[131] implications within the IRP, including demand response. PGE's DSP modeled current and potential demand response programs, including technologies (storage, smart thermostats, electric vehicles and water heaters) and strategies (peak time rebates and time of use pricing programs) across all customer classes. Three adoption cases, which are the inputs to the IRP, are produced based on industry trends, such as technology cost, heuristics of customer adoption from other utility territories, and policy. **Table 12** and **Table 13** detail the achievable potential by season through the Action Plan period, with the cost-effective potential broken out. The cost-effective potential is integrated within the Need Futures and the Action Plan as the procurement target. The difference between achievable and cost-effective potential is the non-cost-effective potential, included within the IRP as potential resource options and further described in **Section 8.2, Additional distributed energy resources**.

[131] For the purposes of PGE's IRP, we utilize the OPUC's definition of DERs which includes distributed generation resources, distributed energy storage, demand response, energy efficiency and electric vehicles that are connected to the electric distribution power grid. See, UM 2005, Order No. 20-485, Appendix A at 15, fn. 2.

Table 12. Summer demand response/flex load peak impacts

Summer MW peak impacts, achievable potential							
Scenario	2024	2025	2026	2027	2028	2029	2030
High	271	298	310	326	343	359	385
Ref	146	183	211	236	257	274	294
Low	98	118	137	155	173	187	201
Cost-effective, achievable potential (TRC >=1)[132]							
Scenario	2024	2025	2026	2027	2028	2029	2030
High	256	273	278	282	287	287	294
Ref	133	162	183	199	211	218	228
Low	93	110	126	141	155	166	177

Table 13. Winter demand response/flex load peak impacts

Winter MW peak impacts, achievable potential							
Scenario	2024	2025	2026	2027	2028	2029	2030
High	174	191	204	219	234	259	282
Ref	106	134	158	177	194	213	231
Low	68	83	99	113	127	141	152
Cost-effective achievable potential (TRC >=1)							
Scenario	2024	2025	2026	2027	2028	2029	2030
High	165	176	183	188	192	199	205
Ref	98	119	137	149	158	167	174
Low	66	79	92	104	115	126	134

As noted in the DSP Part 2, we expect approximately 228 MW of summer and 174 MW of winter economic achievable demand response (including behind-the-meter storage enrolled

[132] The Total Resource Cost (TRC) test compares the costs and benefits of a resource and determines if the benefits are equal to or outweigh the costs, *i.e.*, TRC >=1, or if the resource is not cost-effective, *i.e.*, the projected costs are not greater than the expected benefits. The TRC test is the primary determinant in the implementation of a demand response and energy efficiency program in Oregon.

in a program) by 2030.[133] The demand response portfolio will likely be dominated by Peak Time Rebates, Energy Partner and Thermostat programs in the near-term. In the latter years of the planning horizon, post 2030, the adoption of building and transportation electrification end-uses increase the demand response potential, especially for programs such as Time of Use when combined with technologies such as smart thermostats, batteries or EVs. Details on the procurement targets across these programs can be found in the DSP Part 1 and Part 2, the 2021 Flexible load Multi-year Plan (MYP) and the 2019 Transportation Electrification Plan (TEP).[134,135,136]

Figure 36 describes the Commission-filed resource plans that help PGE move from planning to procurement for demand response. This process will evolve as PGE's virtual power plant (VPP) capabilities mature. Presently, the DSP forms the basis for all DER forecasts. Demand response forecasts go through the IRP process, where they may be layered with additional demand response previously deemed not cost-effective. Thus, the IRP Action Plan sets a target that combines both the cost-effective and currently non-cost-effective resources. The MYP is where PGE details the programs and procurement strategies for those programs to meet this DR target. The MYP will also highlight any operational concerns that may prevent achievement of the target, which may result in increasing the current targets for the supply side Request for Proposals (RFP) or undertaking a new RFP.

[133] PGE Distribution System Plan (DSP) Part 2 (August 15, 2022), available at: https://downloads.ctfassets.net/416ywc1laqmd/2Fr2nVc4FKONetiVZ8aLWM/b209013acfedf1125ceb7ba2940bac71/DSP_Part_2_-_Full_report.pdf

[134] PGE Distribution System Plan (DSP) Part 1 (October 2021), available at: https://assets.ctfassets.net/416ywc1laqmd/i9dxBweWPkS2CtZQ2lSVg/b9472bf8bdab44cc95bbb39938200859/DSP_2021_Report_Full.pdf

[135] PGE Distribution System Plan (DSP) Part 2 (August 15, 2022), available at: https://downloads.ctfassets.net/416ywc1laqmd/2Fr2nVc4FKONetiVZ8aLWM/b209013acfedf1125ceb7ba2940bac71/DSP_Part_2_-_Full_report.pdf

[136] *In the Matter of Portland General Electric Company, Flexible Load Plan*, UM Docket No. 2141 (filed Nov 3, 2021), the 2021 Flexible Load Multi-Year Plan, available at: https://apps.puc.state.or.us/edockets/edocs.asp?FileType=HAD&FileName=um2141had16243.pdf&DocketID=22696&numSequence=19;

Figure 36. Planning to procurement Demand Response

6.2.3 Energy efficiency

This IRP incorporates the ETO's most recent long-term cost-effective EE savings forecast from May 2022. Additional details on ETO's forecast are provided in **Ext. Study-II, EE methodology**. ETO is working to understand how IRA tax credits might reduce costs. This work is in its infancy and is not captured directly in the IRP. However, the different Need Futures account for how cost changes impact the EE forecast, as described in **Section 4.2, Need Futures**.

From 2026 through 2030, ETO projects that cost-effective energy efficiency will provide ~156 MWa of energy savings averaging about ~31 MWa each year. **Table 14** provides the breakdown of the annual energy efficiency savings by sector and program from 2024 through 2030.

Table 14. Energy efficiency MWa savings breakdown by year, sector and program

Sector	Program	2024	2025	2026	2027	2028	2029	2030
Commercial	New buildings	3.5	3.8	3.8	3.9	3.6	3.5	3.4
Commercial	Existing buildings	9.4	9.2	9.0	9.0	9.1	9.2	9.1
Commercial	Multifamily	1.1	1.0	1.0	1.2	1.5	1.9	2.2
Commercial Total		14.0	14.0	13.8	14.1	14.1	14.6	14.8
Industrial Total		11.0	10.0	9.9	10.0	10.0	10.2	10.2
Residential	Existing homes	3.6	3.9	4.1	4.0	4.5	5.5	6.0
Residential	New homes	1.6	1.8	1.8	2.2	2.0	2.4	2.3
Residential Total		5.2	5.7	6.0	6.2	6.5	7.9	8.4
Yearly Total		30.2	29.7	29.6	30.2	30.6	32.7	33.3

Figure 37 highlights the annual EE forecast or cost-effective potential in MWa that is considered within the Need Futures, as noted in **Chapter 4, Futures and uncertainties**. **Figure 38** provides the same data in a cumulative approach to highlight the aggregate impact of the cost-effective EE. **Ext. Study-II, EE methodology,** also includes details on the annual energy efficiency trends. **Section 8.2.1, Additional energy efficiency**, provides more information on the additional energy efficiency evaluated within this IRP.

Figure 37. Annual EE forecast by adoption scenarios in MWa

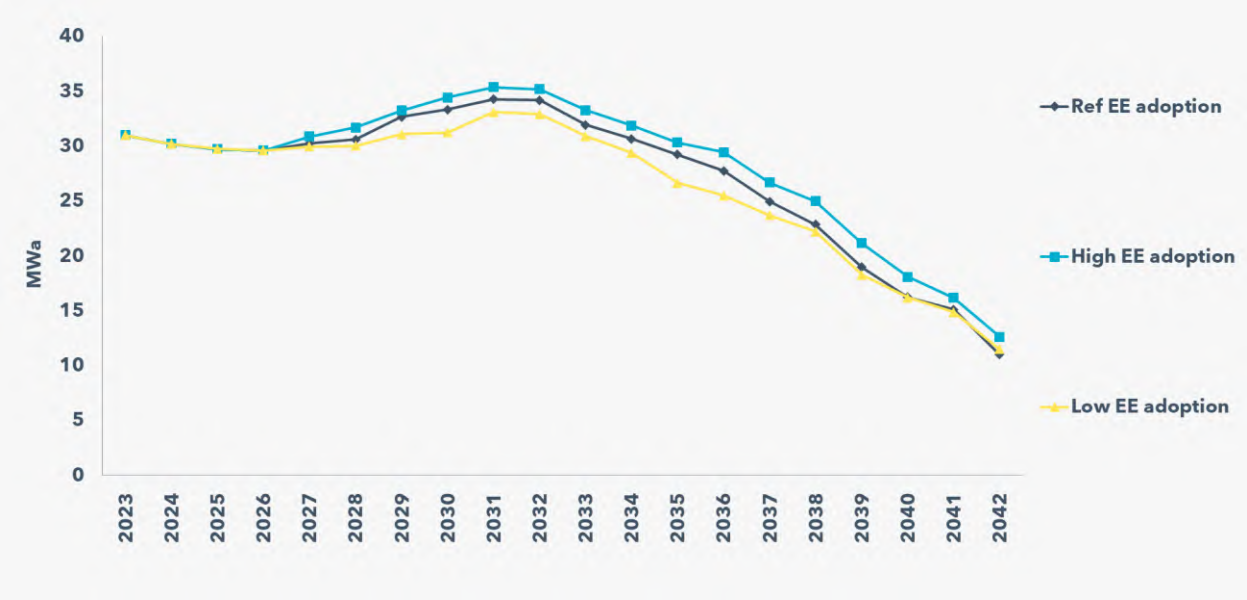
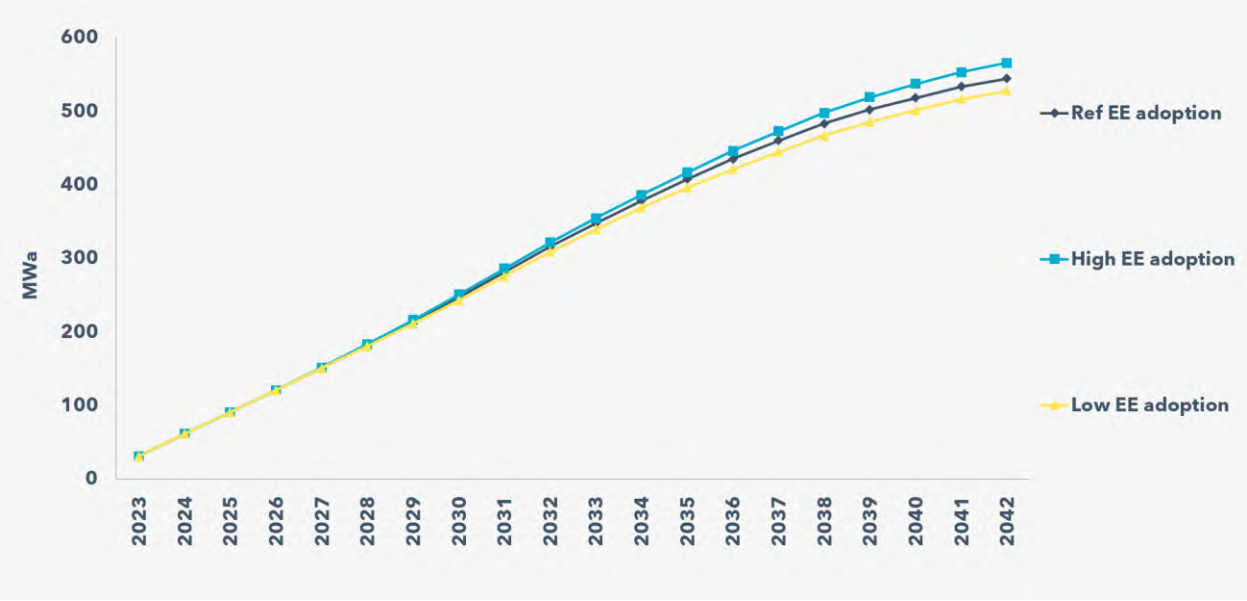


Figure 38. Cumulative EE impact over the planning horizon

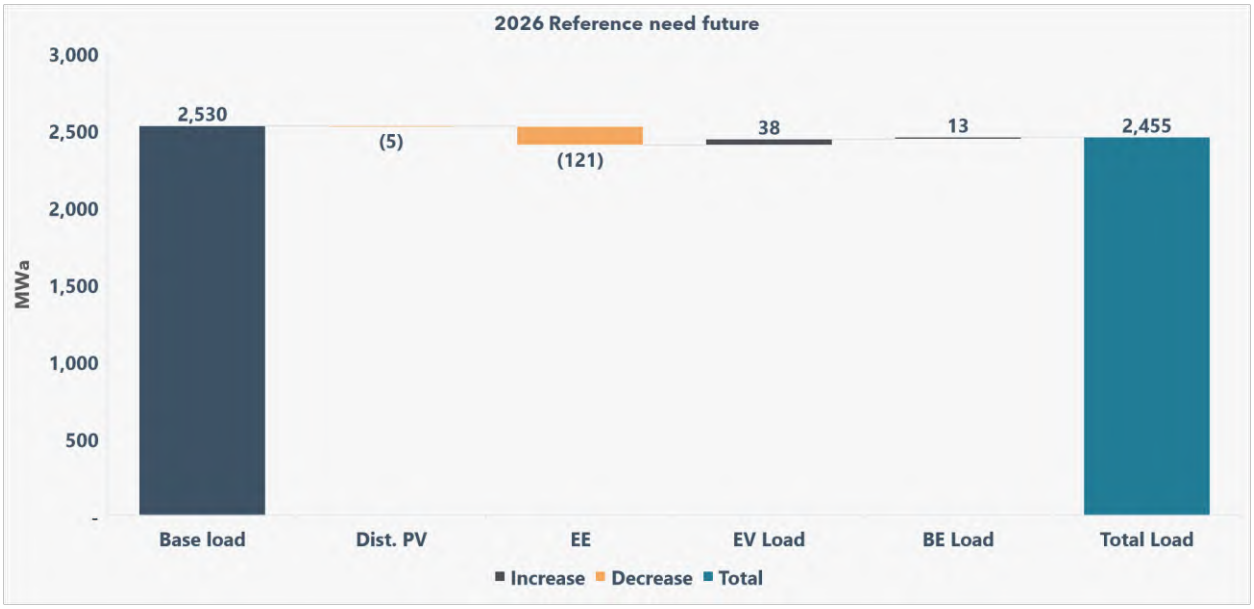


6.3 Load scenarios

The aggregate impact of energy efficiency, other passive DERs and the top-down economic forecast (or Base load forecast) yield the total load used within the IRP. In this section, we graphically present this information. **Figure 39** shows the energy impact of EE savings, distributed PV generation, building electrification and transportation electrification load in the Reference Case for 2026 and 2040. As mentioned earlier, key data considerations for **Figure 39** include the following:

- The base load forecast includes all DER impacts through 2022. The DER impacts highlighted here are the forecasted incremental impacts from 2023 to the year in question.
- The transportation and building electrification loads are gross loads, meaning they do not include the impact of associated demand response programs such as managed charging or time of use, which could increase or decrease loads based on the program design.

Figure 39. Aggregate impact of DERs on base load in 2026 and 2040



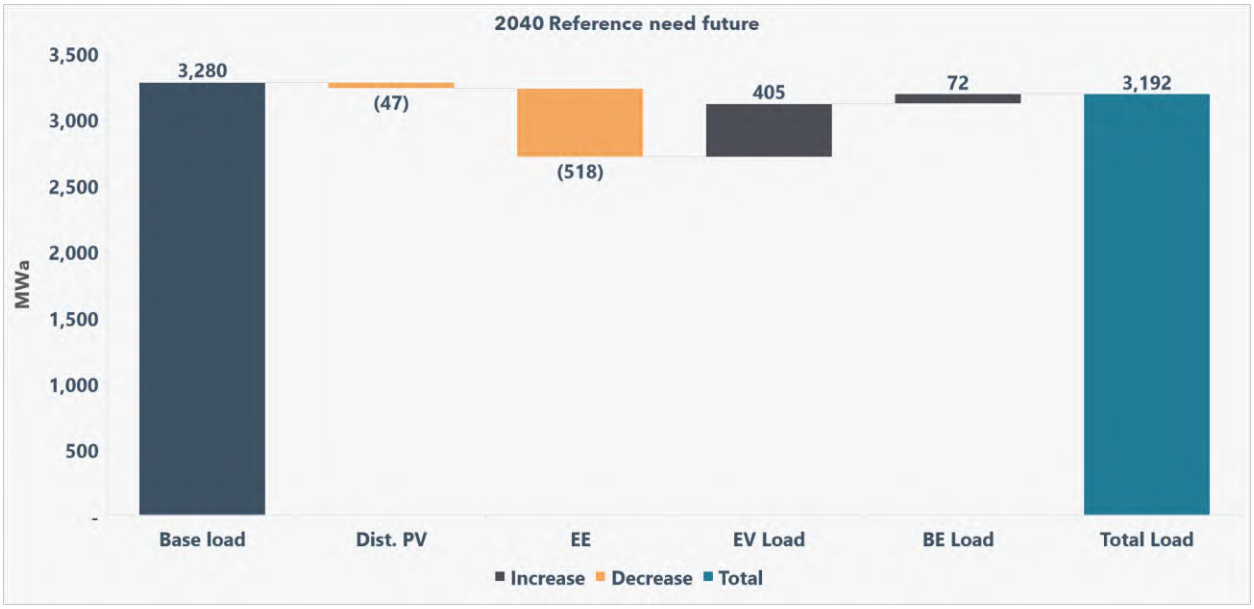
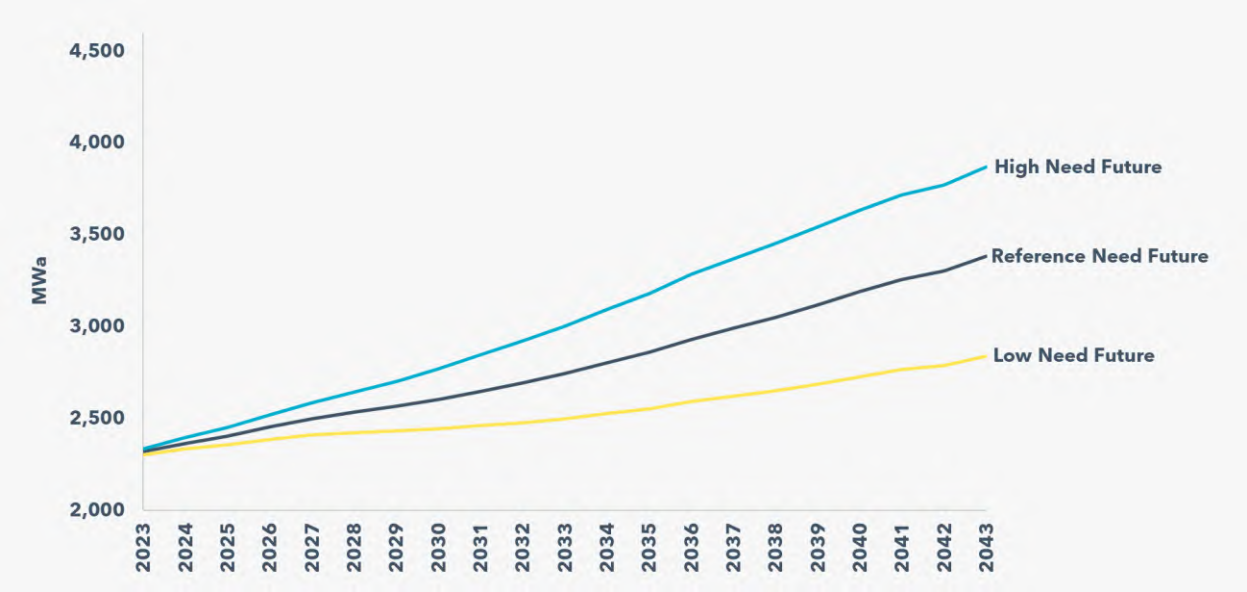


Figure 40 describes the expected total load of each Need Future over the planning horizon showing the divergence between the Need Future over time. By 2030, we expect the total load to be ~2604MWa, growing to just under ~3192MWa by 2040. This represents a 2.1 percent growth between 2030 and 2040. By 2040, the impact of building and transportation electrification is forecast to be ~13 percent of the total load of the system.

Figure 40. Total load for each Need Future over the planning horizon[137]



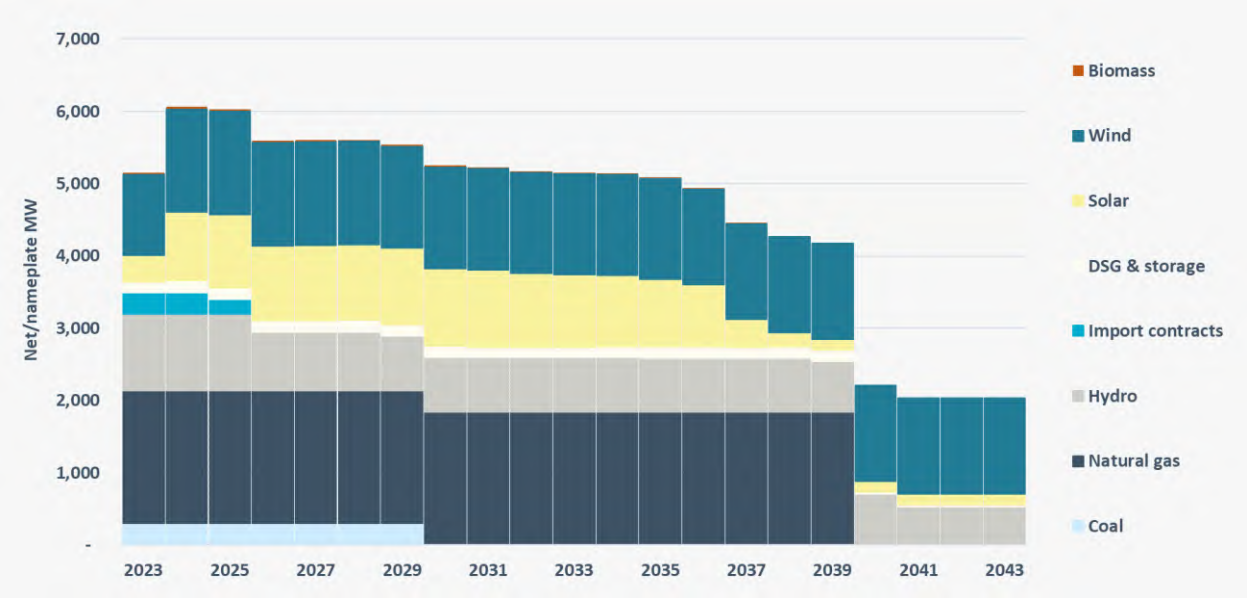
6.4 Existing and contracted resources

PGE owns and contracts a diverse set of resources to meet customer needs. Driven by state policy and company sustainability goals, PGE has been accelerating its transformation to a non-emitting power provider in recent years. This involves acquiring new non-emitting resources, like the Wheatridge Renewable Energy Facility, extending hydroelectric contracts like the Pelton and Round Butte projects, and moving away from coal resources, like the Boardman power plant, which was retired in 2020.

Figure 41 shows the net/nameplate MW of PGE-owned and contracted generating resources, including committed but not yet online resources (like the Clearwater wind project).[138] It does not show future resources from the IRP Preferred Portfolio and assumes no renewals of existing contracts. In 2023, 52 percent of capacity comes from PGE-owned resources, 31 percent from contracted resources and 17 percent from co-ownership and community resources. Net/nameplate MW indicates resource size but is not a good indicator of how much energy or capacity resources can contribute to the system. For a view of PGE's energy position, see **Section 6.5, Energy need**. For a view of PGE's capacity adequacy, see **Section 6.6, Capacity need**.

[137] The figure shows annual energy load forecasts, not peak load forecasts. Peak loads may grow at a different pace due to changing load shapes, demand response programs and other factors.
[138] The figure does not include demand-side resources other than distributed system generation. Net MW may differ from nameplate. Values are approximate.

Figure 41. PGE owned & contracted resources



The forecasted amount of solar on the system grows through 2025 due to bilateral contracts and qualifying facilities coming online.[139] In 2025 and 2026, there is a reduction in resources from the loss of the Avangrid capacity contract (100 MW), the BPA capacity contract (200 MW) and a contract with Douglas PUD. Later in the decade, additional hydro contracts expire, and Colstrip exits the portfolio at the end of 2029. In the mid/late 2030s, the quantity of solar resources on the PGE system declines due to contract expirations.

The IRP only assumes existing contracts will renew if there is a high degree of confidence that the specific contract (or something closely resembling it) will be executed. Contract uncertainty affects IRP resource adequacy and energy needs. PGE would, upon an extension of a contract or entering a new bilateral contract, update the resource need picture (and adjust RFP procurement levels if applicable). **Section 6.10.3, Contract extension sensitivity,** includes additional discussion on the impact of contracts on resource needs.

6.5 Energy need

After detailing forecasts of system demand (in **Sections 6.1-6.3**) and existing supply (**Section 6.4, Existing and contracted resources**), estimates of resource needs in terms of energy and capacity can be derived. This section describes PGE's resource needs through the lens of energy, which represents the amount of electricity demanded and supplied each year and is

[139] These solar projects are largely schedule 202 qualifying facilities and GFI resources.

discussed in terms of megawatt average (MWa) or megawatt hours (MWh).[140,141] **Section 6.6, Capacity need**, describes PGE's needs for capacity, which is discussed in terms of MW, referring to the ability to generate electricity when needed.

6.5.1 Energy-load resource balance

An energy-load resource balance estimates the difference between PGE's forecast customer load (demand) and the expected energy forecasted to be available to serve load (supply). The forecasted amount of energy available annually (in MWa) from owned and contracted non-dispatchable and non-emitting sources is calculated by multiplying the nameplate of each facility by the forecast capacity factor in each year.

The calculation of energy available annually from sources with associated GHG emissions requires a different methodology than was employed in the past due to the GHG emissions regulation created by House Bill (HB) 2021. Prior to the existence of GHG emissions targets, the availability of energy from thermal resources was calculated assuming the availability of the total capacity of PGE's thermal resources to serve load, with adjustments for expected maintenance and outages.

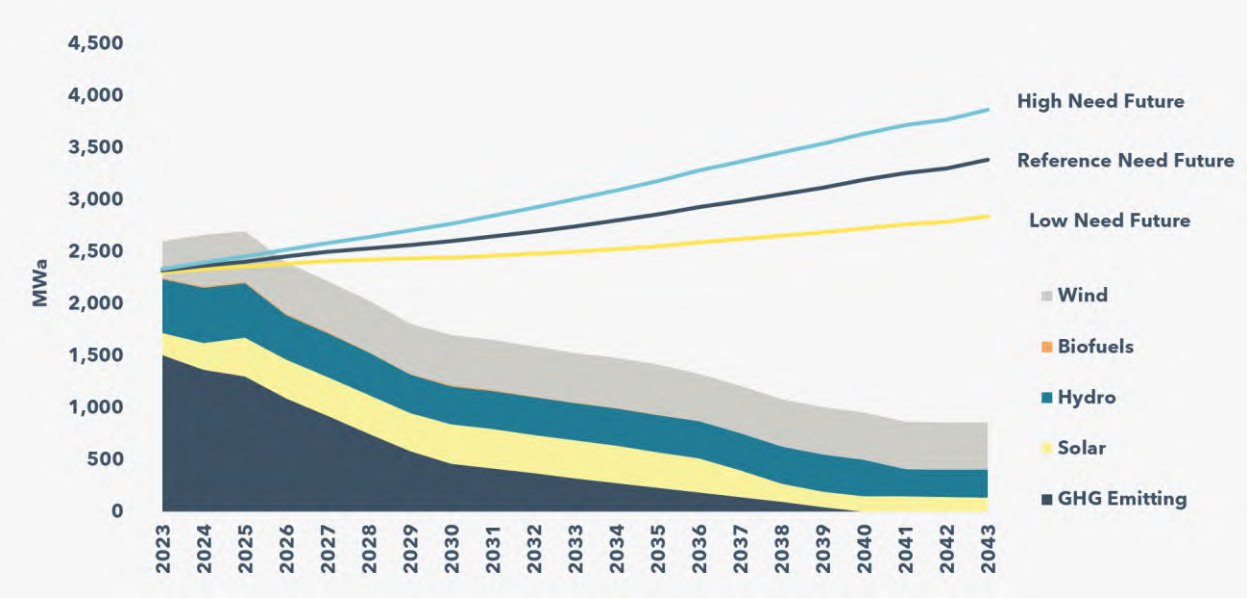
As described in **Section 5.3, Components of IRP emissions reporting**, the total generation levels from PGE's dispatchable thermal plants are determined through economic dispatch from the PZM simulation. To comply with HB 2021 emissions targets, only a portion of the total energy produced by those plants through economic dispatch can be retained to serve Oregon retail load. The amount of energy retained to serve Oregon retail load is determined using PGE's Intermediary GHG model. The amount of energy that can be retained from market purchases and contracts with associated GHG emissions intensity is also accounted for in the Intermediary GHG model.

When combined, the energy retained from GHG-emitting sources and the total energy from non-emitting sources determines the amount of energy allowed to serve Oregon retail load. The forecast of Oregon retail load and the amount of allowed energy that can be used to serve that load are shown in **Figure 42**. The quantity of allowed energy does not include new supply-side resources outside of those from the 2021 RFP and the continued acquisition of energy efficiency, demand response and other demand-side resources.[142] Before any additional incremental resource additions, the Oregon retail load is expected to surpass the

[140] One megawatt is 1 million watts. One megawatt delivered continuously 24 hours a day for a year (8,760 hours) is called an average megawatt.
[141] A megawatt hour (MWh) is equal to 1,000 kilowatts of electricity used continuously for one hour.
[142] As described in **Section 6.2, Distributed Energy Resource (DER) impact on load**, cost-effective EE and DERs are incorporated into PGE's load forecast as a reduction in future loads. Forecast of cost-effective EE and DERs used in this IRP are consistent with what was used in PGE's 2022 Distribution System Plan. Available at: https://portlandgeneral.com/about/who-we-are/resource-planning/distribution-system-planning

allowed energy on PGE's system starting in 2027, with the gap growing through the end of the 20-year planning horizon. The gap between Oregon retail load and allowed energy grows through time because of reductions in the amount of energy retained to serve retail load from GHG-emitting sources, expiration of certain contracts and growth in Oregon retail load through time. Because the entirety of PGE's GHG emissions budget is allocated through the dispatch of owned thermals and energy from contracts and purchases with associated GHG emissions, the future gap between load and allowed energy must be bridged with new non-emitting resources or specified-source non-emitting market purchases.[143]

Figure 42. Energy-load resource balance in linear GHG glidepath in Reference Case future



6.6 Capacity need

Capacity needs describe the effective capacity required to achieve a resource-adequate power system. For example, in 2026, the PGE system has a forecasted capacity need of 506 MW in the summer. This implies that the system needs additional resources that, in the aggregate, provide 506 MW of power during key summer hours.[144] These estimates come out of the PGE resource adequacy model, Sequoia.

[143] Assuming no change in the emissions rate used to account for GHG emissions associated with market purchases from unspecified sources.

[144] An effective load-carrying capability study (ELCC), described in **Chapter 10, Resource economics**, determines how much power different resources can effectively provide. In most cases, a resource's effective capacity is lower than the resource nameplate.

The IRP uses the Sequoia model to calculate the capacity needed to maintain resource adequacy in future years. Sequoia is an hourly model that simulates tens of thousands of weekly combinations of loads and resources to assess power system adequacy under a wide range of conditions.[145] Loads in the model represent all retail customers. Resources include owned and long-term contracted facilities (including Green Future Impact (GFI) resources), the recently signed Clearwater Wind project plus proxy resources that provide capacity and energy expected via the 2021 RFP, cost-effective levels of demand-side resources, and spot power market assumptions (see **Chapter 4, Futures and uncertainties**, for a discussion on the changing region and power market assumptions).[146] The capacity need assessment is performed before the portfolio model is run. As a result, the capacity need assessment does not include new resources identified by the IRP portfolio model. A list of major changes made to the Sequoia model between the 2019 IRP Update and the 2023 IRP is available in **Appendix H, 2023 IRP modeling details**.

GHG-emitting resources are available for use in Sequoia through the year 2039. There may be multiday periods with high GHG-emitting resource utilization to maintain resource adequacy (for example, a period of cold, non-windy weather in the winter). To support this assumption and meet HB 2021 GHG targets, the IRP must select sufficient non-emitting resources to offset GHG-emitting generation usage annually.[147]

For the IRP, a resource-adequate system must average 2.4 hours of lost load or fewer per season (2.4 LOLH), an interpretation of one outage every 10 years. This standard is for supply and demand-caused outages, not outages due to transmission and distribution system issues (like a downed power line). Additionally, the capacity needs assessment does not examine flexibility needs, like having quick-to-react resources to balance variable energy resources and mitigate forecast errors. See **Section 6.8, Flexibility adequacy**, of this chapter for a discussion on system flexibility needs.

The IRP examines power system capacity needs on a seasonal, summer and winter basis. **Figure 43** shows system capacity needs for summer and winter from 2024 through 2043 in the Reference Case in the solid lines.[148] The dashed lines show capacity needs with a 200 MW hydro-based contract renewing from 2026 through 2030.

[145] PGE developed Sequoia following the 2019 IRP. It was developed to better model energy limited resources and to incorporate process efficiency improvements. Sequoia was used in the 2019 IRP Update and in the PGE 2021 RFP. More information on Sequoia is in **Appendix H, 2023 IRP modeling details.**
[146] The GFI projects in Sequoia are Bakeoven Solar, Daybreak Solar and Pachwáywit Fields solar.
[147] The selection of sufficient non-emitting resources is done in ROSE-E, the capacity expansion model.
[148] Winter is defined as October through March; summer is defined as April through September.

Figure 43. Seasonal capacity need

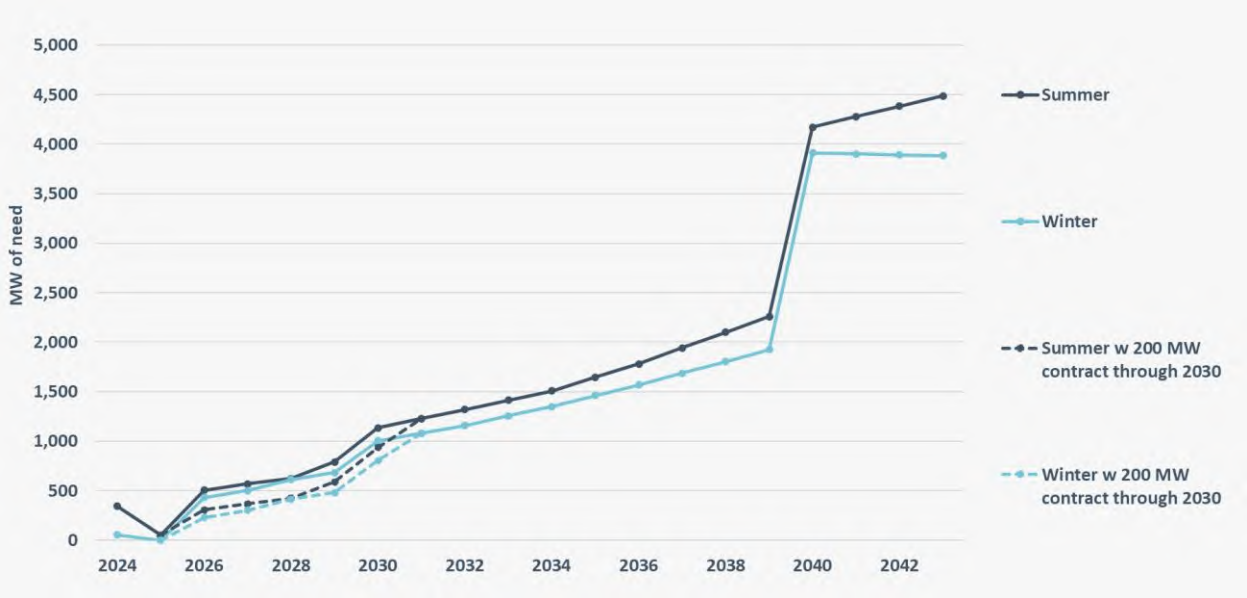
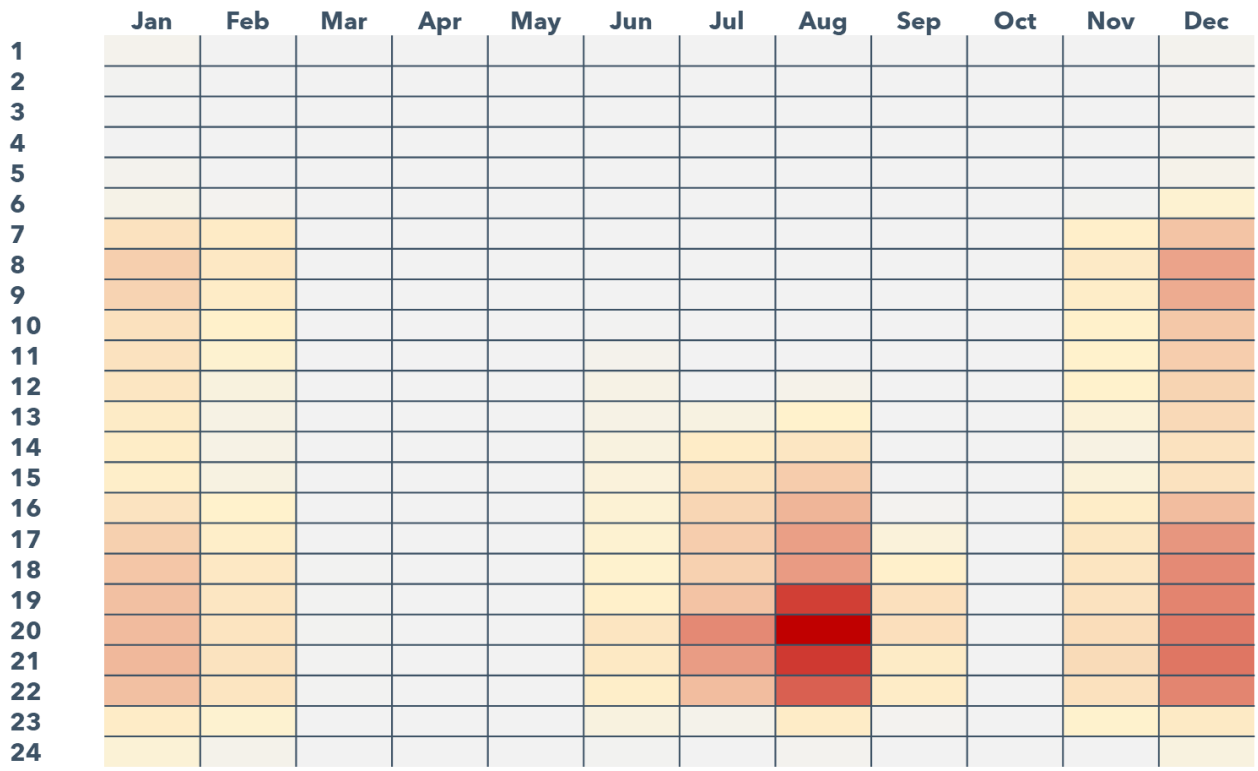


Figure 43 demonstrates larger capacity needs emerging in 2026 (lower levels of needs exist prior to 2026 as well). The increased 2026 need is due to various capacity contracts expiring in 2024 and 2025.[149] A second upward step in capacity need occurs in 2030 when Colstrip exits the portfolio. After 2030, the need for power will grow via two primary drivers. First, steady forecasted load growth for the core system and quickening electrified end-use growth projections push the need up. Second, resource reductions, like the loss of solar contracts in the mid/late 2030s, add to the need. In 2040, the need steps upward when existing GHG emitting resources, like natural gas power plants, can no longer serve retail load (the 2040 need increase could be reduced if existing gas plants are able to convert to a non-emitting fuel).

Figure 44 presents a 12x24 (monthly by hourly) look at 2026 capacity needs. The graph gradients from gray (zero/minimal outages) to red (higher levels of outages). PGE's system sees adequacy challenges in the winter and summer evening hours and the morning in the winter (hours in the heatmap are all Pacific standard time). In 2026, under the Reference Case assumptions, there is a need for 430 MW of effective capacity in the winter and 506 MW in the summer to achieve an adequate system (2.4 LOLH per season).

[149] Contracts may fail to renew for many reasons. These include actions by the seller, like keeping the power to serve local load and/or selling to another entity. The seller may also price the contract higher than other resource/contract options, causing PGE to pursue other options.

Figure 44. 2026 Reference Case capacity need heatmap



6.6.1 Capacity under different Need Futures

There is capacity need uncertainty in the next decade. The uncertainty is due to many factors, including:

- Load growth uncertainty, both from the core forecast and electrification
- Uncertainty regarding the level of demand-side resources PGE will acquire
- Existing contract renegotiation uncertainty
- This IRP examines low and High Need Futures to test uncertainty associated with loads and demand-side resources. See **Chapter 4, Futures and uncertainties**, for more information on Need Futures. **Figure 45** shows the capacity needs of the low and high-needs futures and the Reference Case. In 2026, summer need ranges from 364 MW in the low case to 617 MW in the high case. **Section 6.10, Need sensitivities**, examines how different qualifying facility forecasts, electrification projections, contracts and Colstrip impact capacity needs.

Figure 45. Capacity need under different futures

6.7 RPS need

The Renewable Portfolio Standard (RPS) was established as a law in Oregon in 2007. In 2016, Senate Bill (SB) 1547 escalated the RPS requirements for electric utilities to meet customer energy needs with 50 percent of electricity from renewable resources by 2040 (see **Table 15**).[150]

Table 15. RPS obligations per SB 1547

Year	RPS requirement (% of retail sales)	RPS requirement MWa (reference need)
2025	27%	491
2030	35%	691
2035	45%	975
2040	50%	1207

[150] SB 1547 (2016), available at: https://olis.oregonlegislature.gov/liz/2016R1/Downloads/MeasureDocument/SB1547/Enrolled

In conjunction with meeting HB 2021 requirements, PGE projects that without incremental renewable resource actions, RPS obligations will exceed the quantities of Renewable Energy Certificates (RECs) available from generation from existing RPS-eligible resources in the Low, Reference and High Cases beginning in 2030 when RPS requirements increase from 27 percent to 35 percent of the retail load. PGE's forecasted physical RPS shortage[151] in 2030 is illustrated in **Figure 46** and **Table 16**. For details regarding PGE's expected compliance with the RPS requirements, see **Section 11.5.2, Resulting RPS position**, which compares the RPS requirements with PGE's corresponding RPS position within its Preferred Portfolio.

Figure 46. PGE's physical RPS shortage across Need Futures

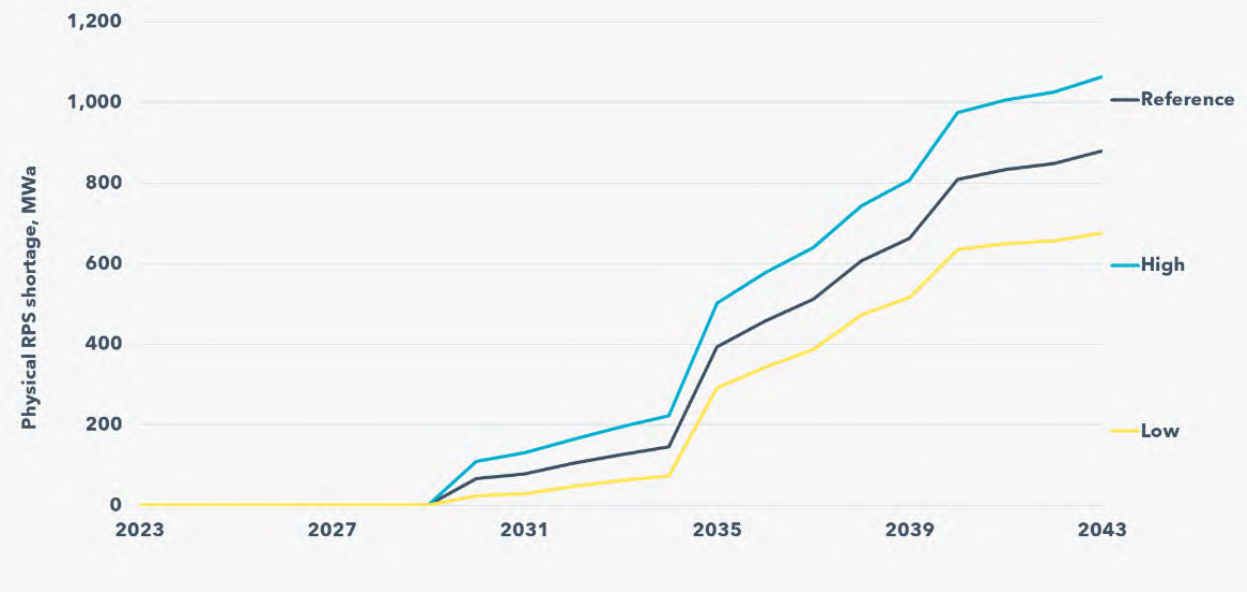


Table 16. Physical RPS shortage in 2030

Need future	2030 physical RPS shortage (MWa)
Reference Case	53
Low Need Future	11
High Need Future	97

[151] A physical RPS shortage is forecasted when RPS obligations exceed PGE's physical RPS position. Physical RPS position is the comparison of forecast-generated Renewable Energy Credit (REC) to the forecast RPS obligation over time. PGE includes information about physical RPS compliance as informational only and does not include any resource additions based on physical compliance. For more detail, see **Section 11.4.6, Targeted policy portfolios**.

6.8 Flexibility adequacy

Resource adequacy need is a vital part of the IRP process to ensure resource actions result in a reliable system. An element of this assessment is understanding operational challenges associated with the need for operating reserves, operational constraints of power plants and errors in supply forecasts and commitments. Unserved energy from these sources can be attributed to a deficit in the system's operational flexibility. Accordingly, flexibility adequacy is an element of resource adequacy that highlights the deficit in a system's operational capabilities hourly and is denoted by a MW flexible adequacy target.

In addition to the hourly flexibility adequacy, the importance of more granular flexibility analyses, from hourly to sub-hourly, is growing as more Variable Energy Resources (VERs) are integrated across the Western Interconnection. Sub-hourly resource integration impacts are a growing body of research across the industry. PGE is still in the learning phase on this topic, focusing on how it can be assessed, understanding its connection with other elements of resource adequacy and hourly flexibility adequacy, and its impact on resource selection.

As part of the flexibility assessment in this IRP, three key critical concepts are analyzed:

- **Flexibility adequacy.** A MW number that represents the magnitude of fast-acting dispatchable resources needed to meet the operational flexibility needs of the system and ensure system reliability. This metric is incorporated within our capacity expansion model, ROSE-E, to address this need by selecting an adequate amount of fast-acting dispatchable resources within the portfolio, such as batteries, pumped storage hydro and other dispatchable resources.
- **Flexibility value.** Represents a benefit value stream that fast-acting dispatchable resources such as batteries and certain DERs should receive for addressing flexibility adequacy. This benefit is integrated into resource economics and is described further in **Section 10.3, Flexibility value and integration cost**.
- **Integration cost.** Represents a cost value stream for VERs such as wind and solar that increase the need for flexibility adequacy due to their variability. This cost is integrated into resource economics and is described further in **Section 10.3, Flexibility value and integration cost**.

For this IRP, PGE worked with Blue Marble Analytics, a third-party consultant, to model all three elements. Blue Marble Analytics used its Grid Path Model to perform the analysis, calibrating the model to the 2019 IRP's flexible adequacy analysis. The findings of the Flexibility Adequacy Study are summarized in the following section, and the entire Blue Marble Analytics study is included in **Ext. Study-IV, Flexibility study**.

6.8.1 Study takeaways and implications

From **Ext. Study-IV, Flexibility study**, we gathered the following findings on flexibility adequacy (**Table 17**):

- **Flexibility challenges in the near- and mid-term are driven by forecast error**. In both the 2026 and 2030 test years, the system experiences inadequate flexibility driven by forecast error. This is where the system, after adjusting hydropower and gas generation, does not have sufficient capacity intra-day to address the magnitude of forecast error during the hours with the highest net load.
- **Flexibility adequacy grows in magnitude and frequency from near- to mid-term.** The study results indicate that in 2026, the system will require an additional 80 MW and 158 MWh of flexible resources to meet the needs of the system, which occur about 0.1 percent of the time. This inadequacy grows to 122 MW and 501 MWh by 2030, with the frequency increasing to 0.3 percent of the time.

Table 17. Flexibility adequacy in 2026 and 2030

	2026	2030
% Timepoints	0.1%	0.3%
Total MWh	158	501
Max MW	80	122

- **Flexibility adequacy challenges are experienced in both summer and winter seasons.** In 2026, the model sees that winter outages are most common in the evenings. In summer, outages are later in the evening, with most outages during hours with the highest net load, usually in the evenings from 6-10 PM. By 2030, as the magnitude and frequency of these outages increase, the outages also occur in the spring and fall seasons. However, the largest outages still occur during evening peaks in summer and winter.
- **System headroom is constrained during summer and winter.** Headroom is defined as how close the system is to experiencing a flexibility-related event. Blue Marble Analytics also assessed the system headroom and found that on a seasonal basis, the system is most constrained in the winter. System headroom is 300 MW or less 25 percent of the time in December and reaches zero in all three winter months as well as in November. Headroom is also frequently constrained in the summer and falls to zero in July, August and September.

- **Diverse resources can help mitigate the increasing flexibility adequacy issues of the system.** Blue Marble found that fast-responding battery storage is required to address flexibility adequacy issues caused by forecast errors. The magnitude of storage required can be reduced when the portfolio includes more diverse VERs. Thus, resource actions that maximize the diversity benefits of VERs that reduce the magnitude of storage needed to address flexibility adequacy issues is one of the more cost-effective methods to address the increasing flexibility challenges. However, given PGE's growing transmission constraints, the costs associated with new transmission for VERs may offset their diversity benefits for flexibility adequacy.

6.8.2 Future improvements/limitations of current data and analysis

As noted, performing a flexibility assessment at the hourly granularity is a critical step in ensuring the reliability of a VERs-dependent system. There is a growing need to understand flexibility needs at the sub-hourly level. Sub-hourly flexibility assessments ensure the system has adequate operational capabilities to balance real-time generation changes of VERs. Assessing the sub-hourly flexibility needs is not only an extremely data and computationally intensive exercise but also raises several questions such as:

- Is there sufficiently granular data of a future system to perform this analysis within resource planning?
- Is there an industry standard or accepted modeling practices to perform such an assessment?
- How do we apply annual reliability targets and standards to a sub-hourly analysis?
- How do we account for the interaction between the different adequacy analyses, ensuring that the needs are not under or over-represented?

PGE is committed to exploring these questions, among others, to ensure we are accurately assessing the system's needs and are developing resource plans to deliver clean energy to customers reliably.

6.9 Climate adaptation

As the climate warms, PGE is adapting its planning process to reflect future temperature and hydrologic conditions. Generally, continued warming in the Northwest will lead to higher temperatures and reduced snowpack (as more precipitation falls as rain rather than snow). Higher temperatures will increase summer electric demand (more AC) and decrease winter demand (less heating). Less snowpack but similar precipitation levels will result in more

hydropower in the winter (more rain increases stream flows) but less hydropower in the summer (due to less snowpack and an earlier melt).[152] The impact of these changes will result in relatively higher capacity needs in the summer (due to more demand and less hydropower) and relatively lower capacity needs in the winter (due to less demand and more hydropower).

6.9.1 Climate change in the 2023 IRP Reference Case

PGE incorporates some elements of climate change into the IRP Reference Case scenario and is studying other aspects of climate change via sensitivities. PGE also engaged a consultancy, Creative Renewable Solutions, to review climate change incorporation in the IRP and to provide recommendations for future improvements. The consultancy's work is in the **Ext. Study-III, Climate adaptation**.

The IRP Reference Case incorporates climate change by:

- Including a warming assumption based on historical temperature trends in the load forecast. See **Section 6.1, Load forecast**, of this chapter for more information on the load forecast.
- Using a reduced number of historical years (30) for both temperature and hydropower sampling in the adequacy model to better reflect climate trends.
- Using climate change model data in the market capacity study.[153] This study dictates how much market power is available to the PGE resource adequacy model, Sequoia. Switching to climate change model data played a role in allowing market power access in the winter and restricting power market access in the summer.

Information on how historical temperature trends align with climate change model data are in **Appendix D, Load forecast methodology**. **Appendix G, Market capacity study**, discusses how climate change data impacted that analysis.

6.9.2 Temperature years in the 2023 IRP adequacy model

The IRP uses the Sequoia model to examine resource adequacy and determine capacity need in future years. The IRP uses the corporate load forecast and historical weather years to create the hourly load profile used in Sequoia and provide load variations based on weather. In past planning work, Sequoia used temperature data from 1980 through the most current year

[152] There is some ability to store/move water from month to month at select Northwest hydroelectric projects, but the overall trend is towards more water/hydro generation in the winter, and less in the summer.
[153] The market capacity study uses data from the Northwest Power & Conservation Council. Their switch to climate change data for the 2021 Power Plan led to the switch in the study.

available. For the 2023 IRP, the model uses the most recent 30 years (1992-2021). The rationale for the switch is that more recent temperature data should better reflect the changing climate.

To test the impact of switching to the 30-year record, Sequoia ran with two sets of temperature years:

- 1980-2021, a 42-year temperature record
- 1992-2021, a 30-year temperature record (created by shortening the 42-year record)

Table 18 shows how the seasonal capacity need in the year 2026 varies depending on the number of temperature years used in the model. In both summer and winter, the capacity need is higher in the 30-year record than in the 42-year record.

Table 18. Seasonal capacity needs in year 2026 under different weather years (MW)[154]

	42 load years	30 load years
Summer	452 MW	506 MW
Winter	417 MW	430 MW

6.9.3 Hydropower climate change data sensitivities

Resource adequacy needs can vary due to hydro conditions. Some years have relatively high levels of hydropower generation due to high levels of snow and rainfall. Due to the higher levels of hydropower generation, those years may have fewer adequacy issues than average. Other years have low levels of hydropower generation due to decreased rain/snow and may face more adequacy challenges than average.

Incorporating a wide and realistic array of hydro conditions in resource adequacy modeling is important to provide an accurate picture of system needs. In past planning work, Sequoia used a 79-year (1929-2007) hydro record. For the 2023 IRP, the model uses the most recent 30-year record (1989-2018). The rationale for the switch is that more recent hydrological records should better reflect the changing climate.

[154] These tests use the 30-year hydro record from the 2023 IRP.

The IRP tests how six different hydro generation records impact resource adequacy needs.[155] The first test uses the historical 1929-2007 record. The second test uses the 30-year historical hydro record (1989-2018). The third through sixth tests use climate change model forecasts for 2020-2048.[156]

Table 19 shows how summer and winter capacity needs in the year 2026 differ by the hydro record. Compared to the 79-year record, all other hydro records result in equal or increased summer capacity needs and decreased winter capacity needs. Going forward, PGE will continue to explore using climate change hydro data in planning work.

Table 19. Year 2026 capacity need (MW)

	79-year record	30-year record	CanESM2	MICRO5	HadGEM2	GFDL
Summer	506 MW	506 MW	514 MW	508 MW	507 MW	506 MW
Winter	432 MW	430 MW	423 MW	426 MW	423 MW	431 MW

6.10 Need sensitivities

For the 2023 IRP, PGE examined the capacity and energy need impacts of different qualifying facility success rates, accelerated load growth beyond the high Need Future, contract renewals, market emissions rates and Colstrip exiting the portfolio four years early.

6.10.1 Qualifying facility sensitivities

PGE ran two qualifying facility (QF) success rate sensitivities focusing on years 2026 and 2030. These sensitivities primarily impact the amount of solar energy on the PGE system. The Reference Case QF assumptions and the two sensitivities follow. In all cases, the IRP assumes that QF contracts do not renew after they end.

[155] For all of the tests, the data which are changing are for the larger PGE owned/contracted projects which are Mid-C contracts associated with specific dams and the Pelton Round Butte projects. The impact of changing the hydro record for smaller hydro projects is not assessed in the IRP.
[156] The 30-year hydro record and climate change hydro data are from BPA/US Army Corps of Engineers and processed by the consultancy Creative Renewable Solutions. More information on the climate models is available in **Ext. Study-III, Climate adaptation**.

- Reference Case: All QFs that are currently online plus 50 percent of executed Schedule 201 projects and 100 percent of executed Schedule 202 projects are included.[157]
- Low QF sensitivity: All QFs that are currently online plus 50 percent of executed Schedule 201 projects and 50 percent of executed Schedule 202 projects are included.
- High QF sensitivity: All QFs that are currently online plus 100 percent of executed Schedule 201 projects and 100 percent of executed Schedule 202 are included.

Table 20 shows capacity needs for winter and summer under the Reference Case and high/low QF case assumptions. With fewer QFs on the system, capacity needs increase; with more QFs on the system, capacity needs decrease or stay the same.

Table 20. Qualifying facility sensitivity Capacity need (MW)

Capacity impact	2026 summer	2026 winter	2030 summer	2030 winter
Low QF	537	431	1,156	1,008
Reference	506	430	1,136	1,004
High QF	505	430	1,136	1,004

On an energy basis, in 2026, the Low QF sensitivity results in a 36MWa decrease in energy, increasing PGE's energy shortage and requiring additional resources. The High QF sensitivity results in a 1MWa increase in energy, reducing the need for new resources.

This analysis shows that delays or terminations of executed QF projects have an impact on capacity and energy needs. To minimize these risks, PGE will continue to monitor the status of QF projects and provide updates within the docket if changes materially impact the Action Plan (**Chapter 12**)**.** PGE continues to advocate in OPUC policy and rulemaking dockets for changes in the power purchase agreements and the contracting process for QFs that would reduce speculative contracting and increase the success rate of QFs that sign power purchase agreements.

[157] Schedule 201 resources are 10 MW nameplate in size or fewer; Schedule 202 resources are greater than 10 MW, not to exceed 80 MW.

6.10.2 Accelerated load growth sensitivity

In addition to the High Need Future which includes the high building and transportation electrification adoption cases from the DSP, the IRP includes an electrification and load sensitivity to understand the combined impact of the following possibilities:

1. Increased building electrification from building-related Climate Protection Program compliance being achieved through electrification only (this results in higher building electrification than the high Need Future).[158]
2. Transportation electrification growth that is more aggressive than the Advanced Clean Cars II policy (this results in higher transportation electrification than the high Need Future).[159]
3. A base load forecast with higher load growth in part due to increased industrial growth.

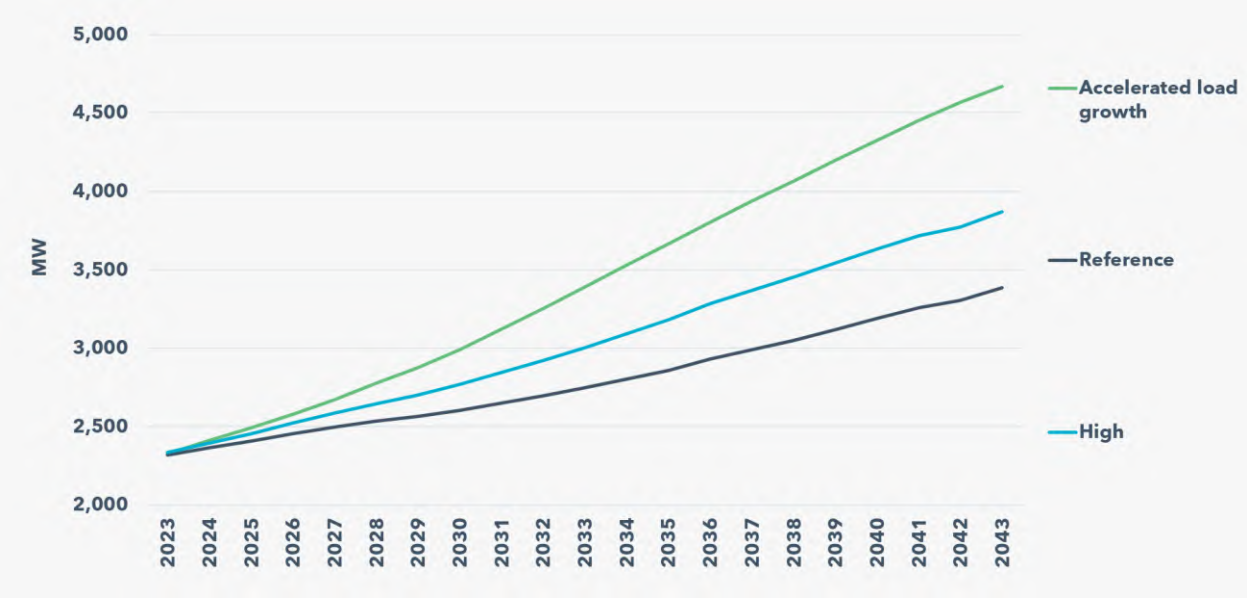
PGE created this sensitivity to test the capacity need and load impact of these possibilities in aggregate. **Table 21** compares the capacity need of this accelerated load growth sensitivity against the IRP's reference Need Future and high Need Future for years 2026 and 2030. **Figure 47** provides the same comparison on an annual energy load basis.

Table 21. Capacity need (MW), high electrification & load sensitivity

Case	2026 summer	2026 winter	2030 summer	2030 winter
Reference	506	430	1,136	1,004
Accelerated load growth	788	870	2,020	2,036
High Need Future	617	628	1,357	1,302

[158] The Climate Protection Program reduces GHG emissions from multiple sources, including space heating, available at: https://www.oregon.gov/deq/ghgp/cpp/pages/default.aspx
[159] Advanced Clean Cars II puts Oregon on a trajectory to 100 percent EV sales for passenger cars, SUVs and light-duty trucks by 2035, available at: https://www.oregon.gov/deq/rulemaking/Pages/CleanCarsII.aspx

Figure 47. Comparison of the accelerated load growth sensitivity with the IRP reference and high Need Future



6.10.3 Contract extension sensitivity

Table 22 estimates how the IRP's capacity and energy needs change based on existing contract renewal. The contracts included in the table are:

- A 100 MW capacity contract to Avangrid that expires in 2024
- A 200 MW capacity contract to BPA that expires in 2025
- Contracts with Douglas PUD that expire in 2025 and 2028

In the following table, all contracts extend through the year 2030. Contract extension reduces both energy and capacity need in all impacted years.

Table 22. Energy and capacity needs with and without select contract extensions

Year	Ref. case energy need (MWa)	Energy need with extensions (MWa)	Ref case summer capacity (MW)	Summer cap with extensions (MW)	Ref case winter capacity (MW)	Winter cap with extensions (MW)
2024	0	0	344	252	55	2
2025	0	0	51	-	-	-
2026	58	0	506	-	430	-
2027	277	167	568	48	502	-

Year	Ref. case energy need (MWa)	Energy need with extensions (MWa)	Ref case summer capacity (MW)	Summer cap with extensions (MW)	Ref case winter capacity (MW)	Winter cap with extensions (MW)
2028	504	388	624	104	614	28
2029	757	603	791	164	683	96
2030	905	756	1,136	540	1,004	458

6.10.4 Market emissions rate sensitivity

PGE buys unspecified power on the market. **Table 23** estimates how energy needs would change in 2030 if half of the recent quantity of unspecified market power purchased by PGE were instead specified as non-emitting. As existing thermal resources are considered always available for resource adequacy purposes, this change in purchases would have no effect on estimated capacity needs. However, such a change would significantly reduce PGE's yearly energy needs, which in turn would reduce the quantity of non-emitting generation and customer price increases. These results suggest that determining the appropriate emission factor of market purchases will be critical going forward to accurately determine resource needs.

Table 23. 2030 energy need with 50 percent of unspecified market purchases designated as non-emitting

2030 Energy Need	MWa
Low Need Future	746
Reference Need Future	905
High Need Future	1,071
Reference Need Future with 50% of unspecified market purchases designated as specified/non-emitting	686

6.10.5 Colstrip sensitivity

Table 24 estimates how capacity and energy needs change in years 2026 through 2029 if Colstrip no longer provides power to retail customers starting in 2026. This differs from the Reference Case assumption of Colstrip providing power to retail customers through the end of 2029. Capacity needs increase when Colstrip no longer provides retail power starting in 2026, but energy needs decrease. The decrease in energy needs is due to Colstrip having a higher GHG intensity than other resources in the portfolio. Its higher GHG intensity results in higher GHG emissions per MWh in the portfolio; thus, fewer MWhs from GHG-emitting sources are kept for retail load service. This accounting happens in the Intermediary GHG model (see **Chapter 5, GHG emissions forecasting**, for details on that model).

Table 24. Energy and capacity needs with and without Colstrip

Year	Ref. case energy need (MWa)	Energy need w/o Colstrip (MWa)	Ref case summer capacity (MW)	Summer cap w/o Colstrip (MW)	Ref case winter capacity (MW)	Winter cap w/o Colstrip (MW)
2024	0	0	344	344	55	55
2025	0	0	51	51	-	-
2026	58	0	506	799	430	726
2027	277	138	568	858	502	797
2028	504	406	624	917	614	902
2029	757	683	791	1,083	683	974
2030	905	905	1,136	1,136	1,004	1,004

Chapter 7. Community benefits indicators and community-based renewable energy

While our Integrated Resource Plan (IRP) has historically focused on least-cost, least-risk modeling as the foundation for providing safe, reliable and affordable power to customers, House Bill (HB) 2021 and OPUC guidelines for utilities' Clean Energy Plans expand the focus of resource planning to be more inclusive of the broader community benefits of resource options and the opportunities for Community-based Renewable Energy resources (CBREs). This chapter describes PGE's approach to the Community Lens topic as outlined in the OPUC's UM 2225, which provided guidance on the development of community benefits indicators (CBIs), the inclusion of a CBRE potential study and the identification of CBRE opportunities.

Chapter highlights

- Portland General Electric's (PGE's) Community Lens Potential study defines our approach to the CBRE forecast and identifies 155 megawatts (MW) of CBRE potential by 2030.
- PGE incorporates CBIs within our IRP using a 10 percent adder for our Resource CBI pathway and a scoring methodology for our Portfolio CBI pathway.
- PGE will continue to evolve our approach to CBIs and CBREs through our Community Learning Labs and by working with our communities to identify future CBRE opportunities through our community Request for Proposals (RFP) and development of non-wires solutions (NWS).

7.1 Community benefits indicators (CBIs)

7.1.1 Defining community benefits indicators

PGE defines a CBI as an equity tool that can be applied to modeling, analysis, scoring metrics, procurement, programs and reporting to inform decisions related to planning activities. CBIs aim to assist in pursuing equitable outcomes and beneficial long-term impacts to environmental justice (EJ) communities, tribes and the most vulnerable communities.

To begin our work, we reviewed OPUC guidance under Order 22-390 regarding CBIs and their application to CBRE analysis and IRP portfolio analysis. Based on the OPUC's guidance in Order 22-390, CBIs are divided into five categories:

- Resilience (customer and system)
- Economic
- Environmental
- Energy equity
- Health and community wellbeing

Additionally, PGE reviewed the OPUC's Attachment A from Order 22-390 (also referred to as "Attachment A").[160] Attachment A was provided by a coalition of Energy Advocates detailing 15 distinct CBIs the Commission and utilities should consider. We reviewed the list of recommended CBIs from our communities within Attachment A and the broader literature around CBIs and the experiences of other utility jurisdictions (e.g., Washington's Clean Energy Transformation Act requirements). Utilizing this information, we worked with communities and stakeholders within our Community Learning Labs to identify additional CBIs and which CBIs are most important to our communities.

[160] See *In the Matter of Portland General Electric Company, House Bill Investigation into Clean Energy Plans*, UM Docket No. 2225, Order No. 22-390 (Oct 25, 2022), Appendix A at 65 (Attachment A Stakeholder CBI Proposal), available at: https://apps.puc.state.or.us/orders/2022ords/22-390.pdf.

PGE will continue working with our communities and other stakeholders through the Community Learning Labs and other venues to develop more standardized information to guide implementation efforts and accountability around community benefits moving forward. This work includes:

- Developing metrics used to measure these benefits.
- Establishing a baseline of the current state of these benefits, where feasible.
- Determining thresholds/criteria for success.

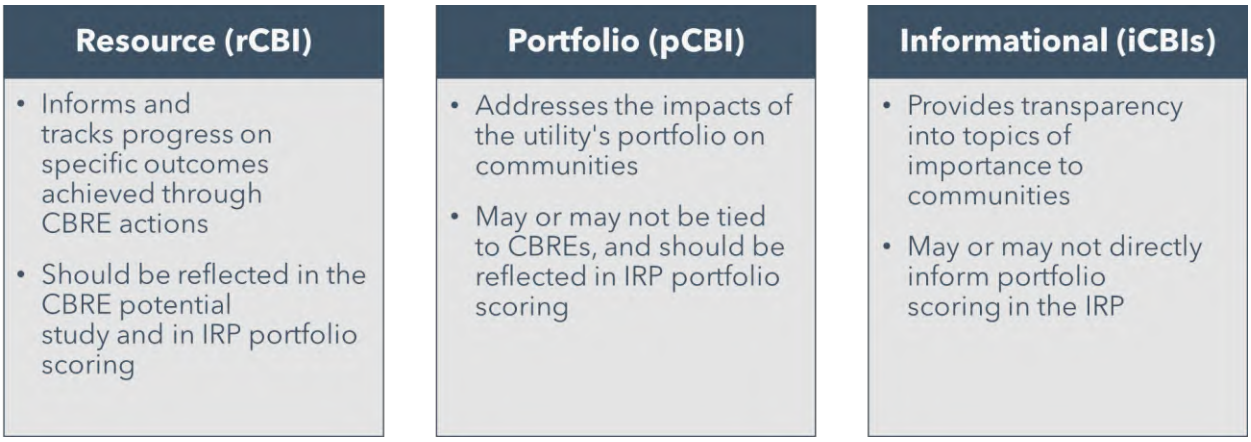
7.1.2 Community benefits indicator pathways

PGE views CBIs as an important component of an inclusive process of the clean energy transition, helping us identify opportunities for communities to benefit from investments to achieve emissions targets. As discussed further in **Chapter 14, Community equity lens and engagement** PGE conducted community engagement within our Community Learning Labs to develop our initial approach to CBIs. Our goals were to identify CBIs of interest to our communities, identify baseline metrics where possible, and share objectives and goals for improving and updating those metrics in subsequent CEP and IRP filings.

PGE heard from our communities and stakeholders that CBIs are important within the planning process because they can influence how utilities make resource investment decisions. We also heard they are important to the implementation of Oregon's HB 2021. Based on this feedback, we developed and categorized CBIs into two groups: quantifiable and qualitative. Quantifiable CBIs refer to benefits that can be measured or expressed as a value. Qualitative CBIs refer to benefits that cannot be expressed as a value but can be described based on quality rather than quantity.

CBIs were then placed into one of three pathways: Resource, Portfolio and Informational, as per OPUC Order 22-390, which states that initial CEPs should include at least one interim CBIs for each pathway. Resource and Portfolio CBIs are considered quantifiable benefits for this CEP and Informational CBIs are qualitative. **Figure 48** illustrates the different pathways related to CBIs as defined by the OPUC's Order 22-390.

Figure 48. OPUC Order 22-390: CBI Pathways



Identifying, measuring and applying CBIs is new to PGE's energy resource planning and resource acquisition process. As described in **Section 7.2.1, Defining CBREs**, for the first step in the IRP portfolio analysis, PGE developed initial CBRE proxy values to reflect a variety of potential CBIs, which allow for distinguishing the energy system benefits of these resources from their relative contribution to community benefits. However, as we move to procure CBREs and initiate program planning and project development, it may be important to develop a set of CBIs that are both quantifiable and measurable.

As a starting point, we apply the Resource and Portfolio pathways to IRP modeling. We use the first pathway, Resource CBIs or rCBIs, to inform and track progress on actions related to CBREs. We use the second pathway, Portfolio CBIs or pCBIs, to address the impacts of the utility's portfolio on communities, which should be reflected in IRP portfolio scoring. For Informational CBIs or iCBIs, we include indicators that may provide transparency into important topics for communities.

7.1.3 Resource community benefits indicators

The OPUC provided guidance within their Community Lens Topics for UM 2225 for Resource CBIs (referred to as CBRE-focused CBIs) that rCBIs are used to "inform and track progress on CBRE actions and should be reflected in the CBRE potential study and in IRP portfolio scoring."[161] When developing rCBIs, PGE evaluated how to incorporate new benefits for the community within portfolio analysis, which is the IRP's process of resource selection. Portfolio analysis is used to understand future long-term resource needs, analyze the expected costs

[161] See *In the Matter of Portland General Electric Company, House Bill Investigation into Clean Energy Plans*, UM Docket No. 2225, Order No. 22-390 (Oct 25, 2022) at 39, available at: https://apps.puc.state.or.us/orders/2022ords/22-390.pdf

and associated risks of the alternatives to meet those needs, and determine the best set of resources to meet those needs for customers.

To integrate rCBIs into portfolio analysis, PGE used a process similar to the 1980 Northwest Power Act for energy efficiency, which allows the flexibility of choosing an adder from 10 percent to 50 percent.[162] Leveraging that approach, PGE created an rCBI adder that reduces the cost of a CBRE resource by 10 percent. We applied this 10 percent credit to the CBRE fixed cost for each of the three proxy CBRE resources evaluated, making them relatively more competitive compared to other supply-side options. A comparison of this credit relative to the other costs and benefits associated with the proxy CBRE resource value is displayed in **Section 10.9, Resource community benefits indicators**.

7.1.4 Portfolio community benefits indicators

The OPUC provided guidance within their Community Lens Topics for UM 2225 for Portfolio CBIs (pCBI) that pCBIs "address the impacts of the utility's portfolio on communities, may or may not be tied to CBREs and should be reflected in IRP portfolio scoring."[163]

PGE defines a portfolio as a fixed set of resource decisions in all scenarios. Our capacity expansion model, ROSE-E, selects the optimal set of incremental resource additions given the parameters in each scenario. As described in **Section 11.1.1, GHG emissions**, all resource buildouts are designed to meet or exceed the GHG emissions targets established in HB 2021. These resources are selected within the IRP process under consultation with our stakeholders to ensure that the best set of resources are selected. While cost and risk have traditionally been included in portfolio analysis, PGE includes pCBIs in this portfolio analysis to ensure that community benefits are maximized.

Portfolio CBIs are meant to adjust portfolio analysis scoring. PGE introduces pCBIs as a proxy for all supplemental community benefits that may come from the addition of CBREs. Portfolio benefits are 1 MW of CBRE equals 1 unit of community benefit. This metric reflects the unspecified portfolio benefits associated with the CBRE additions.

[162] Northwest Power Act, 16 United States Code Chapter 12H (1994 & Supp. I 1995). Act of Dec. 5, 1980, 94 Stat. 2697. Public Law No. 96-501, S. 885, §839a(4)(D), available at: https://www.congress.gov/96/statute/STATUTE-94/STATUTE-94-Pg2697.pdf.

[163] *In the Matter of Portland General Electric Company, House Bill Investigation into Clean Energy Plans*, UM Docket No. 2225, Order No. 22-390, pg. 39, available at: https://apps.puc.state.or.us/orders/2022ords/22-390.pdf

7.1.5 DSP community targeting assessment

As part of PGE's DSP Part 2, we developed a Community Targeting Assessment that evaluated locational distributed energy resource (DER) potential with respect to various customer and community metrics.[164] We view this study as foundational to continued development of the CBRE framework for the CEP and IRP moving forward. During its initial development, we worked with our communities to review which variables and data sources were most relevant to developing a DEI lens to apply to distribution planning.[165] We then combined this information with environmental and resiliency variables to develop a final list, which informed a set of categories for ranking and scoring different investments (**Table 25**). PGE continues to evolve our resiliency analysis and variables; we expect the indicators shown in **Table 25** to progress beyond traditional utility reliability metrics to incorporate customer-centric metrics, resilience measures and grid constraints.

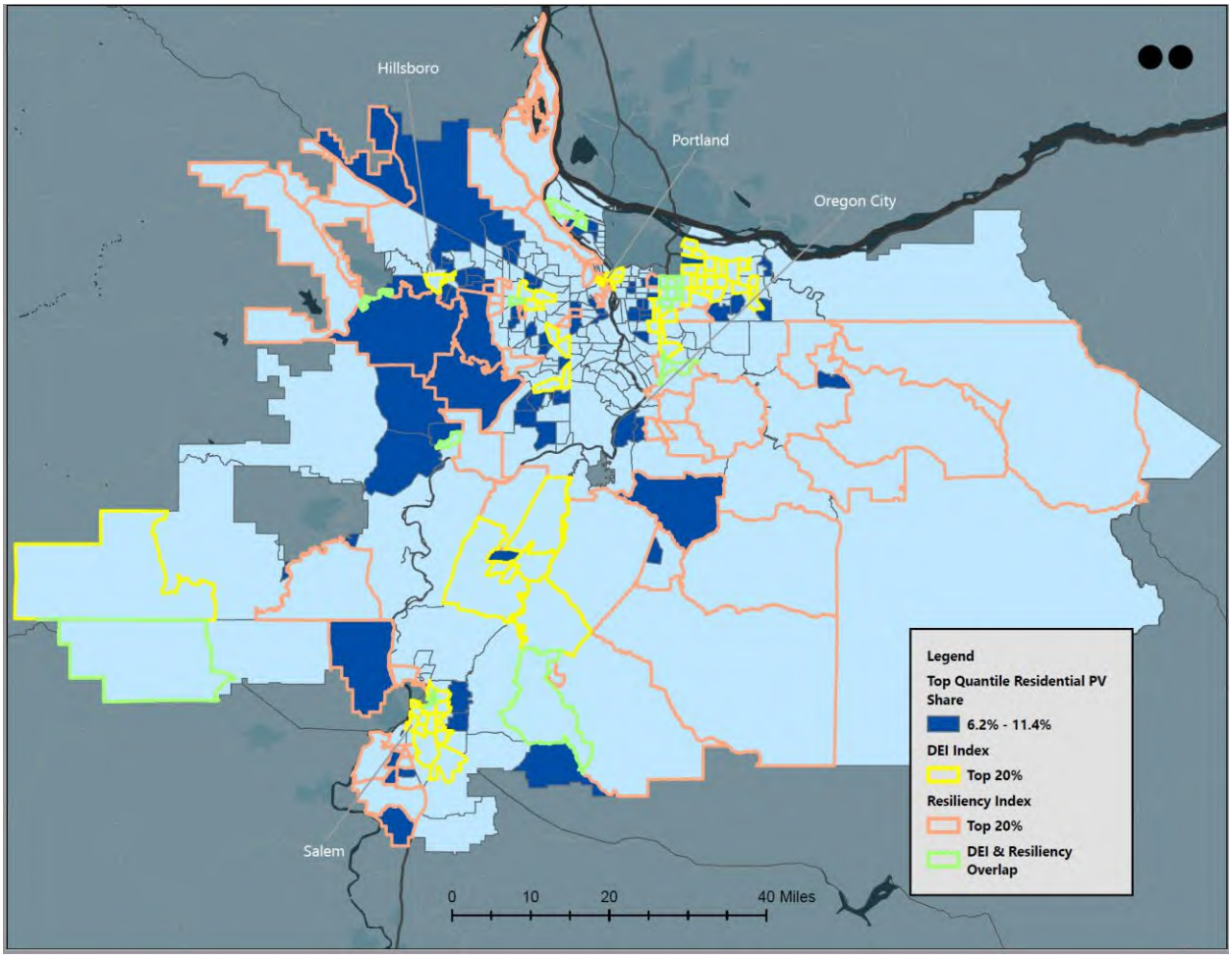
Table 25. DSP variable selection for index development

DEI category	Environmental category	Resilience category
Energy burden	Proximity to environmental hazard waste	Hour-loss power substation
Housing type	Respiratory hazard index	Hour-loss power transmission
Owner/renter	Ozone	System Average Interruption Duration Index (duration of outages)
Race		Seismic risk
Households without internet		
Households with disabilities		

[164] PGE's DSP Part II Appendix N, available at: https://portlandgeneral.com/about/who-we-are/resource-planning/distribution-system-planning/dsp-resources-materials
[165] *Id.* at Chapter 2.

PGE leveraged this work to inform the combined CEP and IRP by assessing baseline metrics for new CBIs and applying these categories to CBREs. For example, **Figure 49** presents a PGE service area map with an overlay of the top quintile of census tracts with the highest scores for DEI and resilience and the top quintile of census tracts with the highest solar photovoltaic (PV) adoption (represented as a percentage of total residential households) by 2030. This work was conducted in 2022 as part of our DSP Part 2. It demonstrates where solar PV adoption may be lower than average and where additional CBREs could add resilience and DEI benefits. Together, these efforts will help to improve the future delivery of community benefits through targeted procurement or program development to identified communities.

Figure 49. PV example strategy Intersection of PV adoption with DEI and resilience by 2030



7.1.6 Informational community benefits indicators

The OPUC provided guidance within their Community Lens Topics for UM 2225 for Informational CBIs (iCBIs) that iCBIs "may or may not directly inform portfolio scoring in the IRP."[166]

PGE described our approach to developing interim rCBI and pCBIs for the purpose of the IRP. This section describes our approach to identifying Informational CBIs, or iCBIs. Informational CBIs will continue to shape our planning activities moving forward. As we continue to iterate with our communities through our Community Learning Labs and develop additional experience designing and implementing CBREs, we will leverage Attachment A and additional CBIs identified through our community engagement efforts. **Table 26** provides an overview of the interim CBIs that have resulted from our work thus far.

PGE intends to further refine and develop quantifiable and measurable CBI metrics where feasible. Our CBI strategy will continue to improve through robust conversations with stakeholders and continued community engagement throughout the CEP and DSP processes.

Table 26. Interim CBI metrics and roadmap for future development

CBI Category	CBI	Metric	Description
Energy Equity, Health & Community Wellbeing	CBI 1: Improve participation in clean energy programs by EJ communities	Metric 1A: DER program participation rates for EJ communities	Rate of improvement in customer participation in customer programs (demand response, solar, storage, energy efficiency) compared to baseline
		Metric 1B: Allocation of budget and/or savings goal within DER programs for EJ communities	Increase in share of budget and/or savings goal in customer programs (demand response, solar, storage, energy

[166] I *In the Matter of Portland General Electric Company, House Bill Investigation into Clean Energy Plans*, UM Docket No. 2225, Order No. 22-390, pg. 39, available at: https://apps.puc.state.or.us/orders/2022ords/22-390.pdf

CBI Category	CBI	Metric	Description
			efficiency) compared to baseline
Economic	CBI 2: Increase energy affordability for EJ communities	Metric 2A: Customers experiencing electricity bill burden	Reduction in electricity bill burden over time for low-income and EJ communities compared to baseline
		Metric 2B: Customer arrearages for customers in EJ communities	Reduction in the number of customers in arrearages in EJ communities compared to baseline
		Metric 2C: Number of customer disconnections for non-payment in EJ communities	Reduction in the number of customer disconnections for non-payment in EJ communities compared to baseline
Resiliency (Customer and System)	CBI 3: Improved grid resiliency	Metric 3A: % of customers experiencing frequent or long-duration outages	Increase in the percentage of customers in EJ communities with access to resilient power through grid infrastructure, customer infrastructure or emergency backup power.

CBI Category	CBI	Metric	Description
		Metric 3B: % of customers with access to emergency backup power in EJ communities.	
Economic	CBI 4: Increased access to jobs/economic impact	Metric 4A: Number of clean energy jobs related to CBRE goals and % held by members of EJ communities	Increase the number of clean energy jobs through future CBRE program and procurement activities
		Metric 4B: Support workforce training opportunities for EJ communities	Participate in diverse workforce development initiatives
Environmental	CBI 5: Environment	Metric 5A: Reduced GHG emissions	Reductions in annual GHG emissions for retail load

CBI Category	CBI	Metric	Description
Energy Equity, Health & Community Wellbeing	CBI 6: Improve efficiency and housing stock in the utility service area, including low-income housing	Metric 6A: Amount of residential energy efficiency achieved in target communities	Increase efficiency of housing stock in the residential sector, including low-income housing, through increased coordination with ETO and other local and state market actors
		Metric 6B: Work with OHCS, CAAs, ETO and other weatherization/energy efficiency implementors to encourage equitable distribution of benefits from energy efficiency programs in the PGE service area	Participate in working groups to support effective and equitable distribution of weatherization and energy efficiency benefits

7.2 Community-based renewable energy (CBRE)

Through Order 22-390, the OPUC set guidance that utilities' first CEPs should include "a potential study (or studies) that identifies opportunities for CBRE projects developed in coordination with communities that are served by the utility, including EJ communities, and with input from stakeholders and Staff". The potential study should:

- "Inform or directly identify annual acquisition targets (e.g., MW, megawatt hours (MWh)) for CBREs,
- Inform or identify the acquisition targets that appropriately balance cost, risk, the pace of greenhouse gas emissions reductions and community impacts and benefits, and

- Measure community impacts and benefits based on interim CBIs established by the utility."[167]

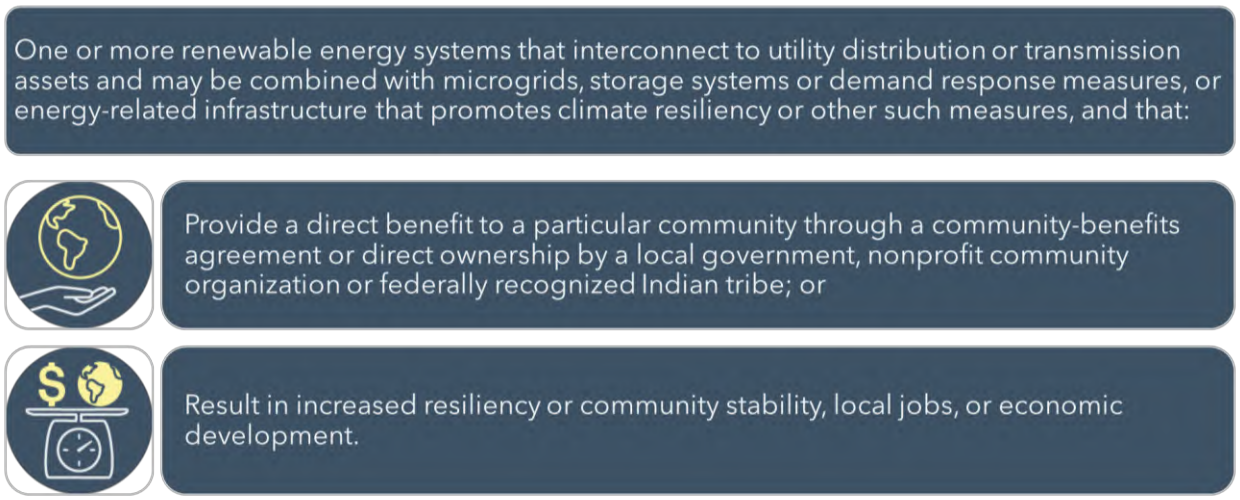
The OPUC also provided guidance that the first CEP should report on the "utility's plan to comply with the state's goal for CBRE projects provided in ORS 469A.210 and explain how the CBRE targets align with this strategy" as well as a "discussion of acquisition targets and actions that the utility will take in the Action Plan window to reach those targets".[168]

7.2.1 Defining CBREs

Oregon has a longstanding public policy interest in promoting small-scale and community-scale renewables.[169] A CBRE is differentiated from other renewable resources, including small-scale renewable energy resources, by the non-energy benefits that it brings to communities. A CBRE results from pairing a range of benefits with a non-emitting generating resource, a storage device, a flexible load program or a combination of investments. HB 2021 builds on that interest while specifically emphasizing resources that provide community benefits and are non-emitting. CBREs are further defined within Section 1(2) of HB 2021 which provides a legal definition for CBREs.[170,171]

[167] *In the Matter of Portland General Electric Company, House Bill Investigation into Clean Energy Plans*, UM Docket No. 2225, Order No. 22-390 (Oct 25, 2022) at 38, available at: https://apps.puc.state.or.us/orders/2022ords/22-390.pdf
[168] *Id.* at 39, available at: https://apps.puc.state.or.us/orders/2022ords/22-390.pdf
[169] The term "Community-based renewable energy" was initially added to Oregon statute by Senate Bill (SB) 838 in 2007, which put in place Oregon's Renewable Portfolio Standard. At that time, CBRE was not specifically defined and was indirectly associated with a policy goal of 8 percent for small-scale (20 MW or less) renewables by 2025. This goal was revised into a target by subsequent legislation (SB 1547 in 2016). Only with passage of HB 2021 were the community benefits of CBRE defined in statute and associated with direction for utilities to…"Examine the costs and opportunities of offsetting energy generated from fossil fuels with community-based renewable energy." *See* Section 4(4d) available at: https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2021/Enrolled
[170] *See* HB 2021 (2021), Section 2(2), available at: https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2021/Enrolled
[171] *In the Matter of Small Scale Renewable Energy Projects Rulemaking*, Docket No. AR 622, Order No. 21-464 (Dec 15, 2021), at 6, the Commission stated: "Some participants in the rulemaking process recommended that we define 'community-based renewable energy projects' and limit eligible resources to those that both satisfy the explicit requirements in subsection (2) of the statute *and* meet some definition of 'community-based.' We decline to adopt this recommendation."

Figure 50. HB 2021 definition of CBRE



Additionally, HB 2021's CBRE definition describes resources on both the transmission and distribution system as well as energy-related infrastructure needed to support these investments. To evaluate CBRE potential for inclusion in resource planning, we used the HB 2021 definition as a starting point and sought input from community groups via our community engagement processes. The CBRE definition used in this initial CEP focuses on community-level resource types that offer the potential to align grid value, energy system benefits, community benefits and progress toward our 2030 small-scale renewables target.

For this CEP, we focus our CBRE analysis on small-scale non-emitting resources that also provide community benefits. In **Section 7.2.1.1, Community lens potential study**, we describe our approach to establishing the incremental CBRE technical potential which informed IRP analysis and target setting for CBREs. Our potential study identifies 155 MW of incremental technical potential by 2030. This aligns with CBRE goals found in community climate action plans such as City of Portland and Multnomah County. We then describe our approach to developing proxy CBRE resources that inform IRP portfolio analysis that meet the guidance provided by the OPUC through Order 22-390.

7.2.1.1 Community lens potential study

The transition to a clean energy future provides many opportunities to improve environmental and public health outcomes, spur local economic activity and job creation, and increase community resiliency in the face of growing threats posed by climate change. CBREs may provide some of these benefits while helping to meet our emissions targets.

Along with our communities and stakeholders, we seek to better understand the role these important resources play in ensuring an affordable, reliable, clean electric system.

Commission guidance on implementing initial CEPs outlined key questions and considerations for conducting a "Community Lens" potential study for CBREs.[172] The Community Lens was discussed throughout CEP regulatory proceedings and largely covered questions regarding incorporating community benefits and impacts, addressing resiliency opportunities and the potential role of CBREs in offsetting fossil fuels.

The Commission provided guidance on expectations for the Community Lens potential study, which states the study should either inform or directly identify annual megawatt (MW) or megawatt-hour (MWh) targets related to CBRE, report on the utility's plan to comply with the state's CBRE targets and explain how the CBRE targets align with the broader CBRE acquisition strategy.[173] In this section, PGE details our approach to the first Community Lens potential study, including methodology, community input and results.

7.2.1.2 Community lens potential study methodology

Community needs and interests in clean energy projects were recurring themes in conversations surrounding the development of both DSP and CEP guidelines.[174] Therefore, we began our consideration of CBRE potential by incorporating community and stakeholder feedback received during our DSP process into a revised DER forecast.[175]

Figure 51 depicts our overall process flow to establish CBRE targets, highlighting the places where community and stakeholder input help shape our direction.

[172] *In the Matter of Public Utility Commission of Oregon, House Bill 2021 Investigation into Clean Energy Plans*, Docket No. UM 2225, Order No. 22-390 (Oct 25, 2022), available at: https://apps.puc.state.or.us/orders/2022ords/22-390.pdf
[173] *Id.*, Appendix A at 38.
[174] For example, see UM Docket No. 2005, Order No. 20-485, Appendix A at 31, available at: https://apps.puc.state.or.us/orders/2020ords/20-485.pdf
[175] For additional information regarding PGE's DER forecasting, see PGE's DSP Part 2, available at: https://downloads.ctfassets.net/416ywc1laqmd/2Fr2nVc4FKONetiVZ8aLWM/b209013acfedf1125ceb7ba2940bac71/DSP_Part_2_-_Full_report.pdf.

Figure 51. Overall CBRE potential methodology process flow

DSP Partner Meeting input and literature review

PGE first considered the feedback we received from our communities and stakeholders during the development of our DSP. Throughout the DSP process, we learned the importance of helping our communities understand and draw connections between utility regulatory processes when they may not have the bandwidth to engage in the many and varied proceedings related to distributed energy resources (DERs) and community benefits. PGE identified three topics from our DSP work as being most relevant for the CBRE discussion:

- Resiliency and reliability planning
- Non-wire solutions (NWS) pilot concept development
- Development of equity indicators

After reviewing DSP partner input, PGE conducted a literature review of relevant documents to supplement our understanding of the different themes identified throughout our planning activities, such as:

- Community comments related to CBRE and CBI were submitted under the DSP, Transportation Electrification Plan and CEP to identify key themes and viewpoints among various stakeholders and community members.
- OPUC Staff's straw proposal under UM 2225.[176]

[176] Docket No. UM 2225, Order No. 22-390, Appendix A, at 23-26, *see especially*, "Topic 1. Community Lens Acquisition Targets", and "Topic 2. Opportunities Considered within Community Lens Potential Studies", *id.* at 27, available at: https://apps.puc.state.or.us/orders/2022ords/22-390.pdf

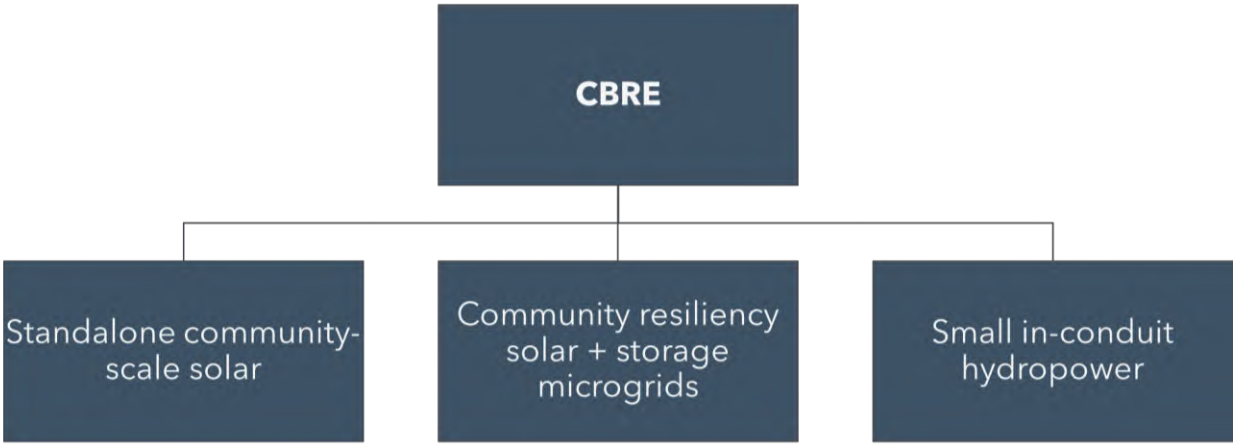
- "Attachment A Stakeholder CBI Proposal" detailing 15 distinct CBIs proposed by a coalition of Energy Advocates.[177]
- Academic journals and industry publications, including The Reliability and Resiliency sections of the Methods, Tools and Resources companion handbook to the National Standard Practice Manual for quantifying the costs and benefits of DERs.[178]
- A recent National Association of Regulatory Utility Commission (NARUC) and National Association of State Energy Officials (NASEO) report on valuing resiliency for microgrids.[179]
- Oregon Department of Energy's (DOE's) CBRE Working Group final report.[180]

Developing CBRE Potential

Based on PGE's review, we initially defined three proxy resources for inclusion in our IRP portfolio analysis, illustrated in **Figure 52**.[181]

[177] *Id.*, Appendix A at 65, The Energy Advocates Attachment A.
[178] Tim Woolf, Courtney Lane, Danielle Goldberg, Erin Camp, Andrew Takasugi, Max Chang and Melissa Whited. "Methods, Tools and Resources: A Handbook for Quantifying Distributed Energy Resource Impacts for Benefit-Cost Analysis" NESP, March 2022, available at: https://www.nationalenergyscreeningproject.org/methods-tools-and-resources/ Also see chapter 8 "Reliability and Resilience", available here: https://www.nationalenergyscreeningproject.org/methods-tools-and-resources/reliability-and-resilience/.
[179] Wilson Rickerson, Kiera Zitelman, Kelsey Jones, "Valuing resilience for Microgrids: Challenges, Innovative Approaches, and State Needs," National Association of Regulatory Utility Commissioners and National Association of State Energy Officials, February 2022, available at: https://www.naseo.org/data/sites/1/documents/publications/NARUC_Resilience_for_Microgrids_INTERACTIVE_021122.pdf
[180] Stephanie Boles, John Cornwell, Rob Del Mar, Jessica Reichers, Adam Schultz, "Study on Small-scale and Community-based Renewable Energy Projects", Oregon Department of Energy, September 2022, available at: https://www.oregon.gov/energy/Data-and-Reports/Documents/2022-Small-Scale-Community-Renewable-Projects-Study.pdf
[181] Due to its associated emissions, biogas was removed from the candidate list, leaving three proxy CBRE resources to be evaluated for potential within our IRP.

Figure 52. Initial CBRE proxy resources identified for IRP portfolio analysis



Many of HB 2021's broadly defined elements of CBREs are captured in IRP analysis via our DER forecast modeling (e.g., rooftop solar, behind-the-meter storage and customer-specific microgrids) and our supply-side proxy resources. Through our assessment, we identified a few characteristics that necessitated additional attention to delineate new proxy CBRE resource types for inclusion into the IRP.

Further informing our potential analysis was the consideration of 2030 targets for small-scale renewable energy projects.[182] As detailed below, our potential study identifies 155 MW of incremental technical CBRE potential by 2030. The IRP models this CBRE potential as additional to the customer-sited resource potential already accounted for within the corporate load forecast and traditional IRP modeling. This customer-sited technical potential, which comes from the DSP, is an additional 377 MW of solar and 61 MW of energy storage by 2030.[183] However, this customer-sited potential cannot be counted toward our small-scale renewable requirement because much of these customer-sited resources would likely be net-

[182] Changes to the small-scale renewables targets established by HB 2021 are codified in law through ORS 469A.210, available at: https://www.oregonlegislature.gov/bills_laws/ors/ors469a.html. The target of 10 percent of "aggregate electrical capacity" may be met through small-scale (20 MW or less) renewable energy projects or certain biomass projects. Community benefits are not an explicit condition of the small-scale renewables definition, while resource size and RPS eligibility are not explicit conditions of the HB 2021 CBRE definition.

[183] For more information on PGE's customer-sited resources please refer to our DSP Part 2 at https://assets.ctfassets.net/416ywc1laqmd/46I2n65SyTv3TUMMdq1l55/a993aebb7b7a84ebd3209d798454a33a/DSP_Part_2_-_Chapter03.pdf#page=22.

energy metered. Net-energy metered resources cannot currently count toward our small-scale renewable requirement imposed by ORS 469A.210. [184]

Through the CBRE potential analysis, PGE considered the extent to which CBRE resources could contribute to the 10 percent small-scale renewables target. We found that in addition to providing benefits to communities, most resources that comprise the 155 MW incremental CBRE potential described in this IRP satisfy the conditions for the small-scale renewables target.

Our CBRE potential study focuses on resources that have the following characteristics:

- Medium- to large-size installations ~ 1-20 MW
- Distribution-connected
- Community-scale (as opposed to behind single customer meter)

To identify the potential for each CBRE included in PGE's IRP portfolio analysis, we relied on the following sources to estimate potential that could inform target setting.

- PGE's AdopDER model (our enterprise DER forecasting model) and community resiliency microgrid technical potential estimates
- Published municipal climate action targets with local resource goals and feedback gathered during product design work with our municipal customers
- ETO small renewable project lists and emerging community resiliency project pipeline
- Oregon Community Solar Program project data[185]
- US DOE National Lab potential studies such as the Oak Ridge National Lab in-conduit hydropower potential study

The following sub-sections provide greater detail about PGE's approach to estimating the potential for each CBRE proxy resource type within our IRP analysis.

[184] Through Order 21-464, the PUC adopted guidance and rules for utility compliance with the small-scale renewables requirement, including the finding that since "net-metered resources are generally viewed as customer-owned resources, reducing the utility's capacity needs, rather than a utility's resource for meeting load," their capacity does not contribute to the target. However, the Commission recognized that approaches toward customer-sited resources are evolving and expressed willingness to "revisit this determination upon a demonstration that this paradigm has changed in ways that make customer-owned resources part of a utility's supply portfolio." See https://apps.puc.state.or.us/orders/2021ords/21-464.pdf.
[185] See *In the Matter of Public Utility Commission of Oregon, Community Solar Program Implementation*, Docket No. UM 1930, Staff Report (September 15, 2021), available at: https://edocs.puc.state.or.us/efdocs/HAU/um1930hau175534.pdf

7.2.2 CBRE resources modeled[186]

Standalone community-scale solar

The definition of a CBRE under HB 2021 includes renewable energy systems that provide community benefits through a community benefits agreement or direct ownership.[187] This desire for local benefits is reflected in different ordinances and climate action plans by local governments and municipal entities. For example, the City of Portland and Multnomah County have both stated goals in their Climate Action Plans that call for 2 percent of their 2030 clean energy targets to be met with community-based renewables and related infrastructure.[188]

To inform PGE's potential estimate for community-scale solar,[189] we first translated those local commitments (i.e., 2 percent of load) into solar nameplate capacity requirements and then scaled these up to reflect what level of resource would be needed to meet a similar local resource goal applied to our entire service area. Finally, we compared this result to the solar components of our microgrid assessment (see **Community resiliency microgrid**) to cross-check this bottom-up method with our established potential estimate.

The community-scale solar proxy used in this IRP is a modified version of a standalone utility-scale solar resource. The modeled CBRE resource for this IRP is responsive to community feedback regarding appropriate size or placement within the community. By using the supply side solar resource as a proxy for a CBRE, modifying for community interest, IRP analysis was explicitly able to include CBRE.

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[186] Additional details regarding the incorporation of CBREs into the IRP analysis can be found in **Section 7.2, Community-based renewable energy (CBRE), Section 7.1.3, Resource community benefits indicators,** and **Section 11.4.3, Community-based renewable energy (CBRE) portfolios.**

[187] ORS 469A.400(2)(a) available at: https://www.oregonlegislature.gov/bills_laws/ors/ors469a.html.

[188] See Multnomah County Resolution No. 2017-046, dated June 1, 2017, available at: https://multco-web7-psh-files-usw2.s3-us-west-2.amazonaws.com/s3fs-public/2017-046.pdf and See City of Portland's 2022-2025 Climate Emergency Workplan, Exhibit A, pg. 4. Available at: https://www.portland.gov/bps/climate-action/documents/climate-emergency-workplan-2022-2025/download.

[189] PGE uses "community-scale solar" here and throughout this document to refer to the proxy CBRE resource type developed for inclusion in IRP analysis. Though similar in name, the resource characterization differs from Oregon's Community Solar Program, which under OAR 860-088-0070 requires projects to be three MW or less.

Community resiliency microgrid

The DOE CBRE working group report states that local resiliency is the primary benefit of CBRE and is also directly distinguishing it from other resource types.[190] This aligns with what PGE has heard during our community engagement process through our DSP Partner Workshops and Community Learning Labs. In addition, resiliency is identified by OPUC Staff in Order 22-390 as being among the highest priorities for the initial CEP.[191] PGE finds community resilience microgrids an intriguing opportunity as they provide significant potential to partner with the utility for funding to meet a variety of community, customer and grid benefits.

Given this focus on resiliency, PGE investigated the potential for community-resiliency microgrids, defined as solar and storage configurations with islanding controls capable of providing continuous power supply during a grid outage. A key distinguishing feature of a microgrid versus other hybrid solar + storage plants modeled in the IRP is the inclusion of advanced communications and controls to coordinate diverse DERs that operate behind the microgrid.[192]

To assess the potential for these resources, we used our AdopDER model, which provides locational DER forecasting.[193] AdopDER contains individual site-level characteristics of all customers and pertinent data about distribution-system factors like frequency and duration of past outages. AdopDER also includes DEI data based on a range of demographic and socioeconomic factors, environmental data including air quality and other EJ criteria and resilience data based on environmental risk factors, such as fire or flood vulnerability areas and grid/system needs, such as long-term outage locations.[194]

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[190] Stephanie Boles, John Cornwell, Rob Del Mar, Jessica Reichers, Adam Schultz, "Study on Small-scale and Community-based Renewable Energy Projects", Oregon Department of Energy, September 2022, at 19, available at: https://www.oregon.gov/energy/Data-and-Reports/Documents/2022-Small-Scale-Community-Renewable-Projects-Study.pdf

[191] See *In the Matter of Public Utility Commission of Oregon, House Bill 2021 Investigation into Clean Energy Plans,* Docket No. UM 2225, Order No. 22-390 (Oct 25, 2022) at 12, available at: https://apps.puc.state.or.us/orders/2022ords/22-390.pdf

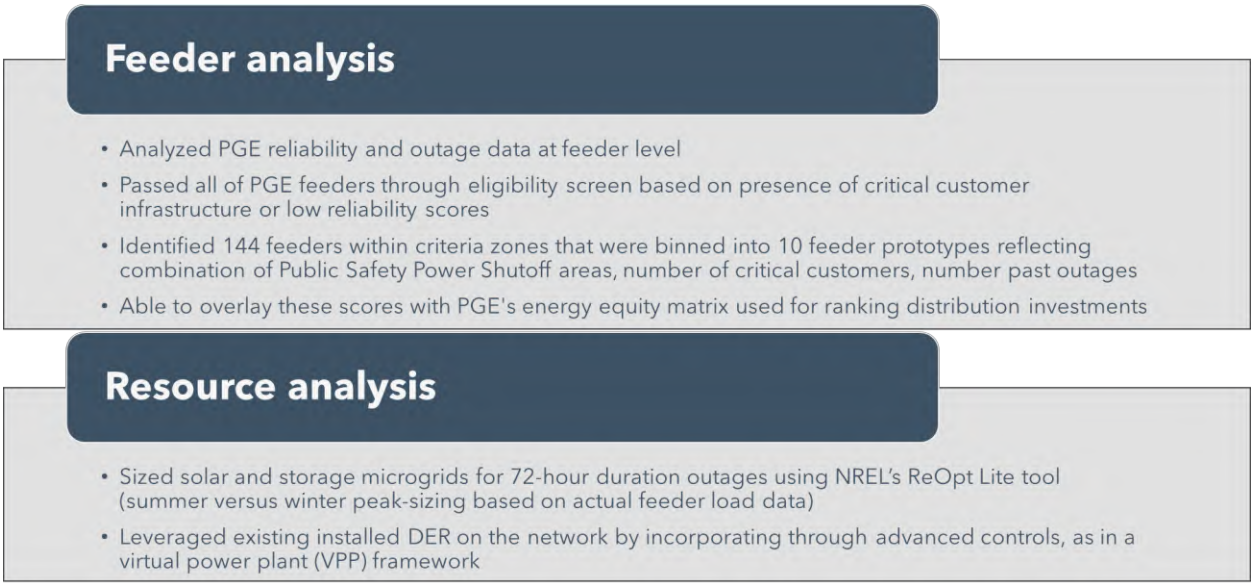
[192] While we distinguish the community-resiliency microgrid as serving multiple customers, it may also aggregate, and control loads behind a single customer meter. In this case, some of the solar PV and storage adoption from our AdopDER model is factored into the MW potential reflected here.

[193] PGE's methodology for locational forecasting can be found in its DSP Part 2, available at: https://assets.ctfassets.net/416ywc1laqmd/4CQCpp0ZlmbQMGDANJKUqN/d2088ce3be4ddc2bc3d0eeab99e7695e/DSP_Part_2_-_AppendixM.pdf.

[194] Additional information regarding PGE's evaluation of DEI, environmental and resiliency variables and data, available at: https://assets.ctfassets.net/416ywc1laqmd/2TbidNAlU4Z5ZsShRrhhb7/d5dcd1cd853d451eb91cdfbec4eeeefe/DSP_Part_2_-_AppendixD.pdf.

Figure 53 highlights the steps to identify community resiliency microgrid potential in the PGE service area using AdopDER.

Figure 53. Community resiliency microgrid potential modeling in AdopDER



The process outlined in the previous figure results in nameplate capacity and energy potential for each resource type within the community resiliency microgrid (i.e., solar nameplate, storage and backup generation). PGE ramped the technical potential based on the "low scenario" annual adoption rate for distributed solar as a proxy to reflect the achievable potential for community resiliency microgrids.

Small in-conduit hydropower

In-conduit hydropower is a low-impact hydropower that places a turbine inside a pressurized water supply or wastewater system. PGE discussed past example projects and potential future leads with ETO staff in assessing the potential for in-conduit hydropower. In addition, we analyzed technical potential data for Oregon taken from a recent Oak Ridge National Lab national potential study for in-conduit hydropower.[195]

Most of Oregon's in-conduit hydropower technical potential comes from irrigation modernization, of which PGE has relatively little in our service area. Therefore, we limited our

[195] Shih-Chieh Kao, Lindsay George, Carly Hansen, *et al.* "An Assessment of Hydropower Potential at National Conduits" Oak Ridge National Lab, ORNL.TM-2022/2431, October 2022, available at: https://info.ornl.gov/sites/publications/Files/Pub176069.pdf

assessment to municipal water supply systems.[196] Overall, the Oak Ridge study found that Oregon has 77 MW of technical potential for in-conduit hydro, of which 12.4 MW is associated with municipal supply systems. We applied an allocation factor of 40 percent of the statewide total to reflect the available potential within our service area. Finally, we increased this potential slowly over time based partly on conversations with ETO staff familiar with past in-conduit projects, the complexities therein, and the relative timescale and cost to complete these projects. Our cost data for this study comes from a companion paper from the Oak Ridge team and the historical cost data provided by ETO.[197]

7.2.2.1 CBRE potential study results

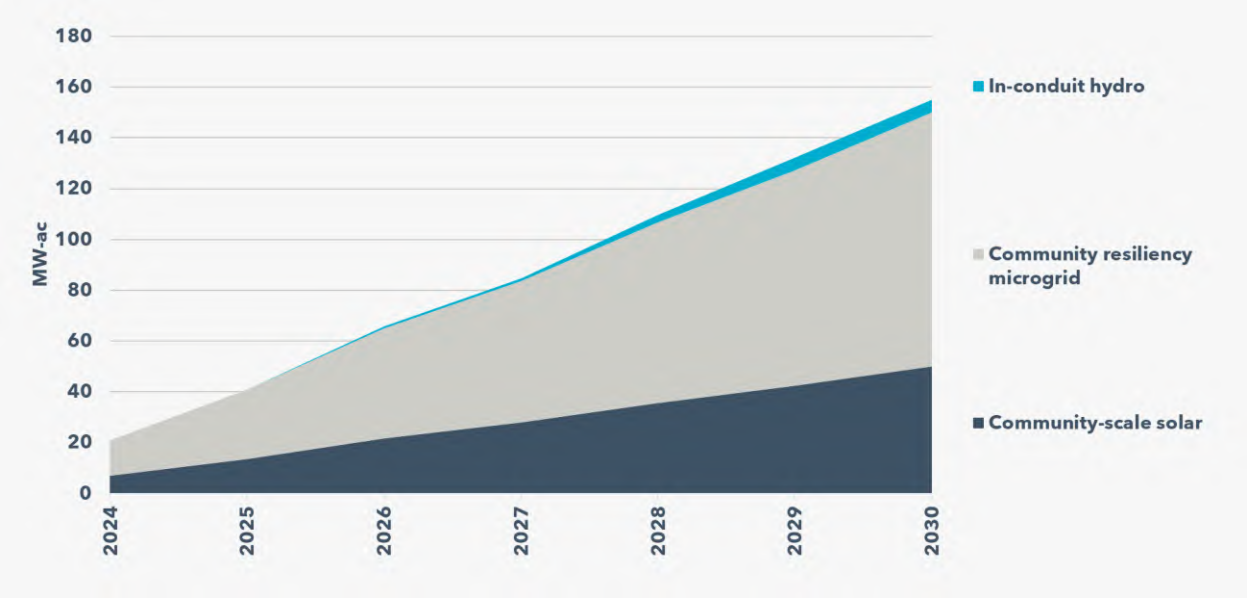
PGE identified 155 MW of nameplate CBRE resource potential by 2030 (**Figure 54**).[198] This potential is increased over time to reflect the time required to develop new delivery channels as may be necessary for these new resource types. We then applied the cost and proxy performance features (e.g., capacity factors) for the three identified proxy CBRE resources to IRP portfolio analysis, described in **Section 11.4.3, Community-based renewable energy (CBRE) portfolios**.

[196] Note that the decision to limit to municipal water supply systems is a modeling choice and helps provide boundaries to the analysis in question. In practice, we expect that some CBRE proposed to meet our Action Plan will include small irrigation modernization projects. In fact, PGE has received interest from one small irrigation district as part of the outreach conducted for this study.

[197] Shih-Chieh Kao, Kurt Johnson, "An Assessment of Energy Potential at Public Drinking Water Systems: Initial Report on Methodology" Oak Ridge National Lab, ORNL/TM-2018/869, CRADA/NFE-17-06776, July 2018. Available at: https://www.ornl.gov/file/assessment-energy-potential-public-drinking-water-systems-initial-report-methodology/display

[198] These totals do not include rooftop solar, which is separately modeled in our 2023 IRP. We have included 377 MW-dc by 2030 in the IRP's reference-need future and 458 MW-dc in the low-need future (the low-need future corresponds to the high distributed solar PV adoption scenario). This delineation was done for the first analysis of CBRE potential within the IRP Portfolio Analysis to avoid double-counting, but in practice we expect rooftop solar to be included in certain program development efforts and procurement activities.

Figure 54. CBRE potential results (cumulative MW)



7.2.2.2 CBRE potential

This section presents the annual potential for CBRE based on PGE's AdopDER modeling and analysis of these proxy resources using the interim approach described previously. We identified the annual megawatt potential shown in **Table 27**.

Table 27. CBRE annual MW potential (cumulative installed nameplate MW-ac capacity)

Resource	2026	2027	2028	2029	2030
Community-scale solar	22	28	36	42	50
Community resiliency microgrid	43	56	71	85	100
In-conduit hydro	1	1	3	5	5
Total	66	85	110	132	155

While we present the detailed CBRE potential here, in alignment with the three CBRE proxy resources included in our initial Community Lens Analysis, this MW potential will be included in the Action Plan at an aggregate level (see **Chapter 12, Action Plan**). As we add CBREs to our system, we expect the actual CBRE resource mix may vary depending on cost, technology evolution and maturation, and market development.

Further discussion of how these targets for CBRE affect the Preferred Portfolio and our Action Plan is included in **Chapter 12, Action Plan**.[199]

7.2.3 Near-term approach within PGE's IRP

PGE incorporated the results of our CBRE potential study described in **Section 7.2.1.1, Community lens potential study,** into portfolio analysis to assess the contributions of these resources toward meeting the system requirements and providing community benefits. Incorporating CBIs and CBREs into PGE's overall portfolio planning process is described in **Chapter 11, Portfolio analysis**.

We include CBRE resource potential and associated CBIs in portfolio analysis to understand the implications that their relative costs, system benefits and CBIs have on various metrics considered within the planning framework and across various portfolio options. To better understand how the inclusion of CBIs in portfolio analysis impacts CBRE resource performance, we developed the following interim approach to applying CBIs in portfolio analysis:

- Include resource-CBI (rCBI) in portfolio optimization as a dollar per megawatt ($/MW) value assigned to each CBRE. The rCBI approach is described more fully in **Section 7.1.3, Resource community benefits indicators**.
- Include portfolio-CBI (pCBI) into portfolio scoring to reflect the increased value of portfolios with CBRE compared to those without. Including pCBIs enables portfolio analysis to evaluate any trade-offs between cost, risk and community benefits. A more detailed overview of how pCBIs influence CBRE selection across portfolios is presented in **Section 11.2, Portfolio scoring**.

Our approach to CBI development, including informational CBIs not included in IRP portfolio analysis, is described further in **Section 7.1, Community benefits indicators.**

[199] In particular, see **Chapter 12, Action Plan** for a summary of actions related to all DER types, including CBRE but also energy efficiency, demand response and rooftop solar. As the most consistently high-ranked CBIs from our communities and stakeholders are related to increasing efficiency in the building stock (through weatherization and targeted energy efficiency programs), we include a separate discussion in the Action Plan related to how our goals for procuring these other, stand-alone DERs may interact with those described in this section to help meet our CBRE goals and provide community benefits.

7.2.4 Refining the market characterization of CBRE

PGE may continue to refine CBRE resource categorization, such as adding different resource types, as we build on our experiences procuring CBREs through the steps outlined in our Action Plan (see **Chapter 12, Action Plan**). Responses to a community RFP, as well as continued developer outreach and engagement, will provide important feedback. We plan to include relevant information in future CBRE potential modeling, including more refined cost data, technology parameters, collaboration opportunities and opportunities for external funding sources.

Another important element of PGE's plan is to continue integrating new CBRE resource characterization into AdopDER. We expect to learn more about the most significant features of CBRE project types to better inform how we characterize CBRE potential in future study rounds. This will better align our CBRE potential methodology with the IRP's well-established demand-side resource forecasting practices. For instance, we will assess opportunities to leverage additional energy efficiency potential estimates from ETO into our CBRE modeling to allow greater assessment of the relative costs and benefits of different combined or hybrid CBRE project types.[200]

7.2.5 CBRE resource procurement activities

7.2.5.1 CBRE RFP

As shared in **Chapter 12, Action Plan**, the Action Plan calls for PGE to conduct an RFP for CBRE resources. The Community RFP will target 66 MW of CBREs to come online by 2026. This initial action will be in service of achieving the 155 MW technical potential of CBREs by 2030. Given the uncertainty described in the eventual composition of the CBRE resource mix that meets the targets outlined in the Action Plan, PGE anticipates a resource acquisition process that prioritizes flexibility and community engagement through an RFP and potential grant funding and program mechanisms.

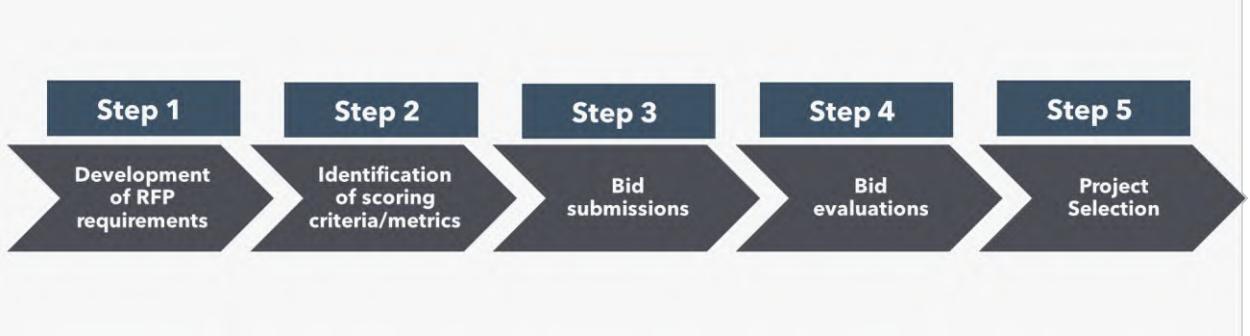
The RFP is intended to be a flexible procurement vehicle that leverages the market resources that align with community preferences. Our goal is to create a collaborative process that results in a co-developed RFP between PGE and the communities we serve. Under this approach, we will aim to design scoring metrics reflective of quantifiable and measurable CBIs through community feedback. The project evaluation and scoring will be guided by

[200] Our treatment of additional non-cost-effective energy efficiency opportunities are described in **Section 8.2.1, Additional energy efficiency**. What we mean here is that in future CEP rounds, we hope to be able to partner with ETO to develop energy efficiency inputs to our CBRE potential modeling from the outset.

community feedback received. The scoring process can also include analysis from the DSP to identify differences in the locational grid value of proposed CBRE projects.

PGE looks forward to future discussions with communities on the timing, technology, location and project selection criteria for CBREs. Additionally, PGE will explore opportunities for federal, state and local grants, as well as the development of future programs to add more CBREs to our system. **Figure 55** illustrates the steps PGE will take starting in 2023 to co-develop the Community RFP with communities and stakeholders.

Figure 55. Community RFP



7.2.5.2 Non-wire Solutions

Moving forward, PGE will engage communities, including EJ communities, to identify other CBRE resource types of interest that may provide meaningful community benefits. Our DSP community engagement opportunities present an excellent chance to continue to refine the definitions and shared understanding around CBREs and identify which CBIs are most meaningful to different communities. Non-wire solutions (NWS) are a particularly robust area of overlap, as a CBRE may end up providing both CBIs (e.g., by reducing bills for low-income customers on a given feeder through targeted program deployment) and achieving incremental locational grid value (e.g., by deferring traditional asset investment needs).

In 2023, we have committed to working with ETO to study NWS opportunities for targeting energy efficiency, customer-sited renewables and battery storage in areas with high grid needs and DEI scores.[201] Given the type of projects for CBRE development that are most meaningful to our communities (e.g., resiliency projects, community gathering places like schools or community centers, or energy efficiency and renewables for low-income multifamily buildings), we expect the NWS planning prioritization with ETO to be a fruitful

[201] See discussion related to how PGE plans to use our DEI index for scoring and ranking grid needs and NWS opportunities in PGE's DSP Part II Chapter 2, available at: https://downloads.ctfassets.net/416ywc1laqmd/2Fr2nVc4FKONetiVZ8aLWM/b209013acfedf1125ceb7ba2940bac71/DSP_Part_2_-_Full_report.pdf.

venue to socialize further CBRE concepts, as well as gather more information about ideal project locations or potential partners for executing CBRE development.

7.2.5.3 Community resiliency hubs

Another customer-facing avenue is our expected continued work to investigate the creation of Community Resiliency Hubs. Community Resiliency Hubs are defined by the US DOE & Environment (DOEE) as "public-serving facilities that provide information and services to build resilient communities before, during and after emergency events."[202] US DOEE further states that Community Resilience Hubs should complement existing emergency response services and "serve communities year-round by promoting health, providing meeting spaces, educating the community about risks and emergency preparedness, and supporting workforce development."

As part of our continued engagement, we will continue to explore Community Resiliency Hubs within our Community Learning Labs that:

- Provide resilience to the community and critical facilities serving that community center's community voices in decisions regarding placement and use of CBREs.
- Create a high-value product that serves the public interest and serves many customers or targets to serve the most vulnerable customers.
- Design accessible and equitable solutions ensuring any solution considers a project's impacts on all customers.

Through PGE's next CBRE potential study, we have an opportunity to learn more from our communities about which projects and programs are most meaningful to them. In addition to the Community Learning Labs, PGE will leverage other stakeholder engagement channels (e.g., DSP and MYP) to socialize and refine our approach for the next CEP. We will work with our communities and community representatives to assess the need for more education and learning regarding CBRE and solicit ideas and input about a suggested direction for future study efforts.

[202] More information on US DOEE's Community Resilience Hubs, available at: https://doee.dc.gov/service/community-resilience-hubs.

7.2.6 CBREs and Oregon's 10 percent small-scale renewable requirement

PGE's support of CBREs is both established and evolving. We see significant potential to widen our CBRE near-term approach to include more community-scale and customer-sited generation paired with energy storage, flexible loads and energy-related infrastructure. As required by ORS 469A.210, PGE has a 10 percent small-scale renewable requirement.[203] We expect the CBRE potential PGE has identified to contribute to that requirement. That requirement uses only one metric (i.e., 20MW or less in size) and does not incorporate community benefits or non-emitting resources. In the past, wholesale projects typically contributed to the goal, which was then 8 percent. Moving forward, we expect the following activities will inform and contribute to the requirement:

- Continued engagement with communities
- Existing programs and procurement strategies such as:
    - Wholesale projects smaller than 20 MW, including PURPA, bilateral contracts and CBREs
    - Oregon Community Solar Program (projects are capped at 3 MW)
- New resources, programs and strategies such as:
    - Community Request for Proposals (RFP), described later in **Section 7.2.10, Further actions and considerations**
    - Virtual power plant (VPP)
    - Federal/local incentives

7.2.7 Continued engagement with communities

PGE's community engagement strategies will provide a forum to discuss CBRE acquisition strategies with communities, stakeholders and OPUC Staff. Key areas of engagement will include the timing, technology, location and project selection criteria for CBREs. We will co-develop the Community RFP with communities and stakeholders beginning in 2023.

[203] Oregon ORS 469A.210 can be found at https://www.oregonlegislature.gov/bills_laws/ors/ors469a.html.

7.2.8 Existing programs and procurement strategies

In recent years we have seen rapid expansion of customer-sited solar that both offsets load and delivers energy to the grid. We anticipate continued and significant expansion of customer-sited solar, especially given the new federal incentives described in **Chapter 2, Accessing support for energy transition**. Many of the existing resources and programs that fall within the CBRE definition also participate in PGE's evolving VPP. Current CBRE investments and programs on PGE's grid that are broadly understood to bring community benefits, include:

- Rooftop solar (residential, commercial, non-profit)
- PGE's residential battery pilot
- Flexible load programs: Energy Partner, Peak Time Rebates, Smart Thermostats, water heaters
- Oregon Community Solar Program
- Resiliency investments in critical facilities such as the Beaverton Public Safety Center

7.2.9 New resources, programs and strategies

PGE's efforts to scale and leverage CBREs underscores the importance of our efforts to expand our Virtual Power Plant (VPP). Enhancing our ability to utilize CBRE investments to support the larger grid's functioning, through incorporation into the VPP, is critical to our decarbonization goals, as described in **Section 8.4, Virtual Power Plant (VPP)**. This will be enabled via monitoring behind-the-meter generation (e.g., smart inverters). Once solar (and other) customer-sited resources are connected, visible and actionable to system operators, they can increasingly be considered supply-side resources for purposes such as resource adequacy, procurement, operations and the small-scale renewables goal.

Section 7.2.4, Refining the market characterization of CBRE describes our near-term acquisition approach. We have an initial target of 66 MW of incremental CBREs by 2026 that we will pursue through both a Community RFP and/or other programmatic approaches. However, even procurement of the entire CBRE potential will still require additional new small-scale renewables to meet the 10 percent small-scale renewables requirement of ORS 469A.210.

PGE will continue to explore opportunities for federal, state and local grants and incentives to improve and offer opportunities that create local jobs, save on energy bills and cost-effectively reduce greenhouse gas emissions and other harmful pollutants. Having access to additional financing opportunities will support and accelerate the development of future

programs and provide unique financial advantages for customers and communities. Federal, state and local grants and incentives are a key ingredient of a socially inclusive, cost-effective energy transition.

7.2.10 Further actions and considerations

Our portfolio analysis finds that CBREs, as considered in the potential study, provide system benefits. Because of the transmission constraints PGE is facing, they compare favorably to larger scale renewable resources in portfolio analysis and comprise an important role in our Action Plan.

Broadly, our Action Plan and related acquisition actions seek to prioritize CBREs that provide community benefits, alongside grid services such as resilience. Today, large-scale CBREs (3 MW and above), can help us meet our CBRE target. These resources could provide benefits to nearby communities through community benefit agreements, as well as on-site renewables deployed at the individual customer-level.[204] However, as we improve on our ability to utilize smaller-scale CBREs at the individual neighborhood level (3 MW and below), CBREs will become an integral part of our VPP. As residential and small commercial renewables become an important part of our capacity planning, this will require changes to the regulatory framework. [205] These changes are needed to accelerate small-scale renewable projects that affordably support decarbonization of the grid. For example, this may require changes to the regulatory framework including net-energy metering and inclusion of net-energy metering as a resource needed to accelerate small scale renewable adoption. To the extent practicable, these resources and changes should provide additional direct benefits to Oregon communities in the forms of creating and sustaining meaningful living wage jobs, promoting workforce equity and increasing energy security and resiliency.

There are also uncertainties and potential risks of CBREs and CBIs to be explored further with our communities, OPUC Staff and other stakeholders. For example, there are many unknowns regarding resources that are not owned and operated by PGE such as how

[204] The US Office of Economic Impact and Diversity defines community benefit agreements as an "agreement signed by community benefit groups and a developer, identifying the community benefits a developer agrees to deliver, in return for community support of the project. Community benefit groups are coalitions comprised of neighborhood associations, faith-based organizations, unions, environmental groups and other stakeholders. Community Benefit Agreement (CBA) Toolkit | Department of Energy.

[205] PGE's DSP Part 1 and Part 2, discusses regulatory evolution and long-term actions within the regulatory framework could accelerate projects that ready the grid for decarbonization, which can be respectively found at: https://assets.ctfassets.net/416ywc1laqmd/7vUdTxBF2cElhG276mH0UZ/2b5ad6bff08b334b101f566c7dfd957a/DSP_2021_Report_Chapter7.pdf and https://assets.ctfassets.net/416ywc1laqmd/5GRLxNj644P2Ty82WkLM5F/dfd5e8376a4eac9d1bf8bc65ec7dbf74/DSP_Part_2_-_Chapter07.pdf#page=5.

community ownership could work or whether third parties would be open to community benefit agreements. Additionally, there are issues regarding third party operations and maintenance standards to address. It will also be important to understand how third-party resources will be integrated into the grid in partnership with utilities and how to protect the security of these resources and facilities. These important topics will need to be considered so that CBREs can be developed to benefit the communities they are intended to serve and serve as grid assets that can benefit all PGE customers.

Chapter 8. Resource options

In this Integrated Resource Plan (IRP), we evaluate a broad set of resources to meet the needs identified in **Chapter 6, Resource needs**. To meet these system needs while reaching the emissions targets established in House Bill (HB) 2021, we focus on analyzing only commercially available technologies applicable through 2030. These resources include both distributed energy resources (DER) and supply-side options. This chapter begins with a discussion of technology trends and an exploration of candidate supply-side options tested in portfolio analysis, including energy storage and renewables. We then describe DER programs and technologies deemed non-cost-effective under prior estimates of cost-effectiveness. We conclude with discussions of how resources are expected to be integrated via Portland General Electric's (PGE's) virtual power plant (VPP), transmission, emerging technologies and the advantages and disadvantages of utility and third-party ownership of resources.

Chapter highlights

- PGE discusses utility-scale supply-side options available for meeting portfolio needs, including wind, solar photovoltaic (solar PV) and energy storage resources, among others.
- The costs and megawatt (MW) potential of additional energy efficiency and demand response are included as resource options in this IRP.
- An analysis showing the adequacy challenges of a decarbonized system based on current resource options, followed by potential long-term resource options and strategies that can help address the challenges.
- A discussion of the benefits and risks of different resource ownership structures for customers is included.

8.1 Utility-scale energy resources

8.1.1 Summary of technologies

The supply-side resources considered in this section represent technically and economically feasible options that are plausible options to meet PGE's needs through 2030. These resources are generally categorized as non-emitting renewable or storage resources. Additionally, natural gas-fueled resources are included for continuity with prior IRPs and in the event that data related to these resources are required for other regulatory proceedings. PGE relies on publicly available information to inform supply-side resource options' cost and performance parameters.[206]

8.1.2 Sources of information

8.1.2.1 Cost and performance parameters

Resource cost and performance parameters form the basis for the economic analysis of generic proxy resources in the IRP. In this IRP, PGE is generally using supply-side resource information from two sources:

- The National Renewable Energy Laboratory produces the Annual Technology Baseline (NREL ATB) to "develop and document transparent, normalized technology cost and performance assumptions" for typical generating resources in the United States.[207]
- The U.S. Energy Information Administration (EIA) commissioned Sargent & Lundy to "evaluate the overnight capital cost and performance characteristics for 25 electric generator types" to reflect these generators in the Annual Energy Outlook 2020 (EIA AEO).[208]
- Resource operating parameters are sourced from the ATB and AEO when possible. Where information needed for PGE's models is not provided in the ATB or AEO, PGE relies on information from other publicly available sources, including past IRPs. Overnight capital costs presented in this chapter are inclusive of interconnection costs. Historical inflation rates were applied to escalate from the EIA and NREL study values. Cost estimates do not explicitly account for supply chain-related disruptions experienced post-

[206] In PGE's recent IRPs, supply-side resource cost and operating parameter information was generally developed by third-party consultants.
[207] NREL. 2021 Electricity ATB, available at: https://atb.nrel.gov/electricity/2021/about.
[208] EIA AEO 2020. "Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies." Prepared by Sargent & Lundy, available at: https://www.eia.gov/analysis/studies/powerplants/capitalcost/

2019.[209] These estimates do not reflect the impacts of the US Department of Commerce's investigation into the potential circumvention of tariffs on certain imported solar panels.

8.1.3 Renewable energy generation

The generation of wind and solar resources in PGE's models is based on input shapes simulated for each resource. PGE simulates hourly renewable generation using NREL's System Advisor Model (SAM). SAM is free software provided by NREL for modeling the performance and economics of renewable energy projects.[210]

8.1.4 Wind and solar weather data

Weather data for wind and solar resources are inputs to SAM (e.g., wind speed and solar irradiance). Onshore wind weather data are sourced from the NREL Wind Integration National Database (WIND) Toolkit for 2007–2014.[211] Offshore wind weather data rely on NREL's Offshore NW Pacific Dataset. The dataset comprises 20 years of weather data covering 2000–2019.[212] NREL's National Solar Radiation Database (NSRDB) is the source of weather data for solar PV simulations.[213] PGE uses NSRDB data for 1998–2020. PGE uses data available from these sources at the time of the analyses.

8.1.5 Methodology for average year Capacity Factor

As discussed in **Appendix H, 2023 IRP modeling details** PGE's energy valuation modeling (PZM simulation, conducted in Aurora) in this IRP uses a representative 8760 hourly shape of energy generation for each renewable resource.[214] These representative shapes are developed from the hourly simulations for each year of available data mentioned in this section, using the following steps:

1. Simulate 8760 hourly shapes for each year with available weather data (e.g., for 10 years of weather data, create 10 simulated 8760 hourly shapes).

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[209] This implicitly assumes that the supply chain issues are temporary.
[210] NREL SAM information, available at: https://sam.nrel.gov/.
[211] NREL WIND Toolkit information, available at: https://www.nrel.gov/grid/wind-toolkit.html and https://developer.nrel.gov/docs/wind/wind-toolkit/.
[212] NREL Offshore NW Pacific dataset information, available at: https://developer.nrel.gov/docs/wind/wind-toolkit/offshore-nw-pacific-download/.
[213] NREL's National Solar Radiation Database information, available at: https://nsrdb.nrel.gov/ and https://developer.nrel.gov/docs/solar/.
[214] In years past, the IRP utilized month-hour average energy shapes for wind and solar resources, specifically. In doing so, resource variability was potentially reduced.

2. Compute the monthly average capacity factors across the data from step #1 (average across 10 years each month).
3. For each month, choose the hourly data from the year that most closely matches the monthly average capacity factor computed in step #2 (if in January, for example, the year five capacity factor is nearest to the average from step #2, the representative shape will use the year five hourly data for January).
4. Use the hourly data from each month selected in step #3 to create the representative shape.

This process results in shapes that closely match the annual capacity factors averaged across the available weather data while maintaining the variability of the underlying hourly data. Using publicly available data from NREL is an attempt to enable transparent and comparable analysis across resources in the IRP. The resulting energy shapes and capacity factors from this analysis will differ from those experienced by resources constructed in the future. Resource developers participating in a competitive procurement process will perform detailed analyses of specific projects to optimize resource economics (cost and performance) with respect to geographic location and resource configuration, among other factors.

8.1.6 Treatment of tax credits

As discussed in **Section 2.1, Federal support for energy transition**, the Inflation Reduction Act (IRA) brought several changes to the tax credit landscape. These changes are expected to have material effects on the economic values of various generation and storage resources. When modeling resources in the IRP, the following assumptions are made:

- Tax credits will phase out over three years beginning in latter 2032, or the year in which the US electricity sector emits 75 percent less CO2 than in 2022. For modeling purposes, all tax credits are assumed to be extended through 2043 (the end of PGE's analysis time horizon). This assumption removes the possibility of tax credit expiration influencing the portfolio optimization process.
- Non-emitting generating resources qualify for 100 percent of the production- or investment-based tax credits.

- Standalone storage resources qualify for 100 percent of the investment-based tax credit without the need for normalization.[215]
- Carbon capture and hydrogen production resources qualify for specific credits outlined in the IRA.
- Tax credits are assumed to be fully monetized in the year they are generated.
- Numerous additional changes within the IRA and the IIJA are not currently built into modeling assumptions. Some of these are:
    - The EE forecast, as noted in **Section 6.2.3, Energy efficiency**, does not contemplate the IRA's tax credits, which include the Residential Energy Efficient Home Improvement Credit, that likely will increase the savings forecasted.
    - The DER forecast, as noted in **Section 6.2, Distributed Energy Resource (DER) impact on load**, also does not capture the impacts of the IRA tax credits, which include rooftop solar, electric vehicles and building electrification, that likely will result in faster adoption of these technologies.
    - The IIJA provides significant funding, which PGE is pursuing as appropriate, for the following areas of interest:
    - $23B to enhance the resiliency of the power infrastructure and investment in renewable energy.
    - $21.5B to develop clean energy demonstrations and research hubs.
    - $5B to boost energy efficiency and clean energy creation.
    - $18B to support electric vehicle (EV) charging deployment, clean transit and school buses, and other transportation electrification funding.

8.1.7 Renewable generation resources

8.1.7.1 Onshore wind

PGE analyzes proxy onshore wind resources at four locations in this IRP: Oregon Columbia River Gorge, Central Montana, Southeastern Washington and east of Casper, Wyoming. The

[215] To achieve 100 percent of the available credits, PGE's analysis assumes that prevailing wage and apprenticeship requirements are met, and that no additional tax credit adders apply, such as the those associated with domestic content, Energy Community or low-income community considerations. The adders, as noted in **Section 2.1.1, Inflation Reduction Act**, disproportionately benefit the ITC over the PTC. PGE will explore different options, including a wholly-owned affiliate, to work around the ITC normalization issue in order to promote a level playing field in future renewable solicitations, which will deliver least cost resources for customers.

Wyoming wind resource is available in PGE's analysis with an assumption of incremental transmission action.[216] For more detail on the costs and benefits associated with the incremental transmission, see **Section 9.4.1, Proxy transmission options identify transmission need**.

The resource configuration is common across the four locations, comprising 3.5 MW turbines with 136-meter rotor diameters and 105-meter hub heights. Standard resource configurations are used to focus the analysis on differences arising from locational characteristics rather than an optimized resource design. Resource cost information is based on EIA AEO data. Capital cost estimates are adjusted by geographic location based on EIA's location-based adjustment factors. Characteristics for the four onshore wind resources are summarized in **Table 28**.

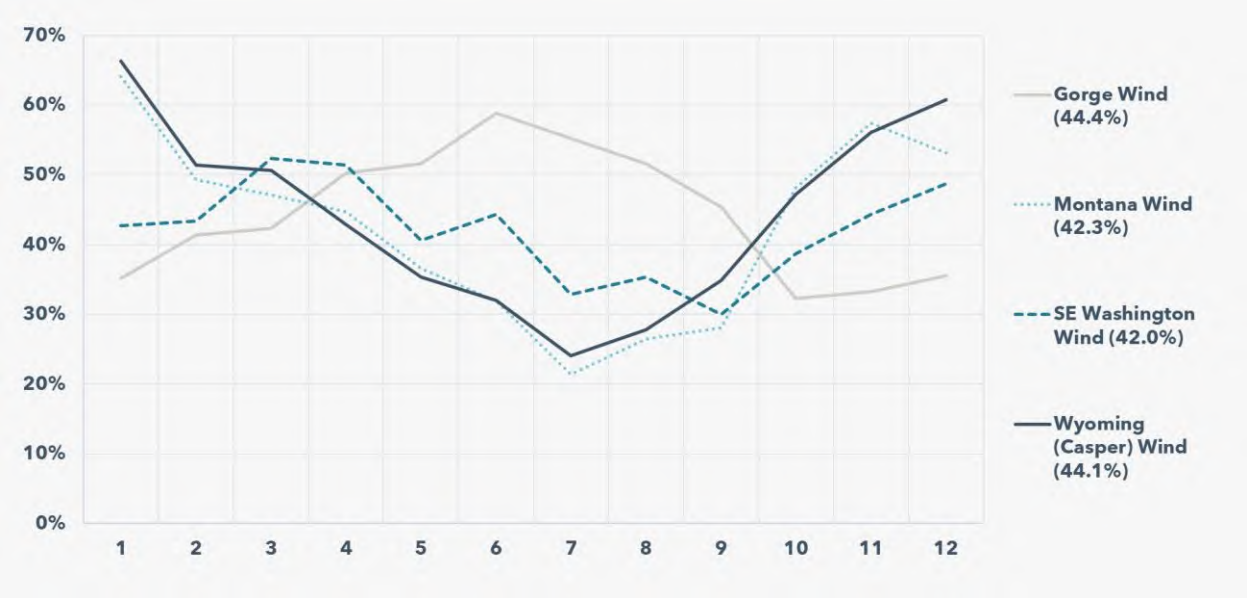
Table 28. 2026 COD onshore wind[217]

	Oregon Columbia Gorge	Central Montana	SE Washington	Casper, Wyoming
Location (Lat., Long.)	45.65, -120.63	46.35, -110.34	46.41, -117.84	43.04, -105.56
Capacity (MW)	300	300	300	300
Capacity Factor (%)	44.4%	42.3%	42.0%	44.1%
O/N Capital Cost ($/kW)	$1,503	$1,457	$1,491	$1,457

Figure 56 summarizes the shape of monthly capacity factors for the various wind resources used for energy valuation in this IRP.

[216] PGE's 2019 IRP included two Oregon-sited proxy wind resources; for purposes of streamlining the resources being analyzed, the Oregon wind site with the superior capacity factor is included in this IRP.
[217] Wind project capacity factor data are from NREL. They do not necessarily comport with historical generation values from these locations from existing projects.

Figure 56. Wind resources monthly capacity factor shapes



8.1.7.2 Solar photovoltaic (PV)

Three Oregon locations are used to represent solar photovoltaic (PV) resources in the IRP: one central Oregon (east of Cascades) location near Christmas Valley, one location with a similar longitude (east of Cascades) but farther north near Wasco and one location with a similar latitude as Wasco but in the Willamette Valley (west of the Cascades) near McMinnville. A solar PV resource near Mead, Nevada, that will be accessed via incremental transmission action is also included in PGE's analysis. Each location is modeled using identical underlying parameter assumptions, so any difference in simulated energy production is attributable to the solar resource. Resource cost and parameter information is based on NREL ATB. Capital cost estimates are adjusted by geographic location based on EIA's location-based adjustment factors. All solar PV resources use single-axis tracking. The inverter loading ratio (ILR) describes the ratio of solar array direct current (DC) capacity to inverter alternating current (AC) rating.[218] The 1.34 ILR modeled in the IRP is consistent with the NREL ATB. ILRs are also discussed further in the context of co-located, or hybrid, solar and battery energy storage resources. A selection of solar PV parameter assumptions is summarized in **Table 29**.

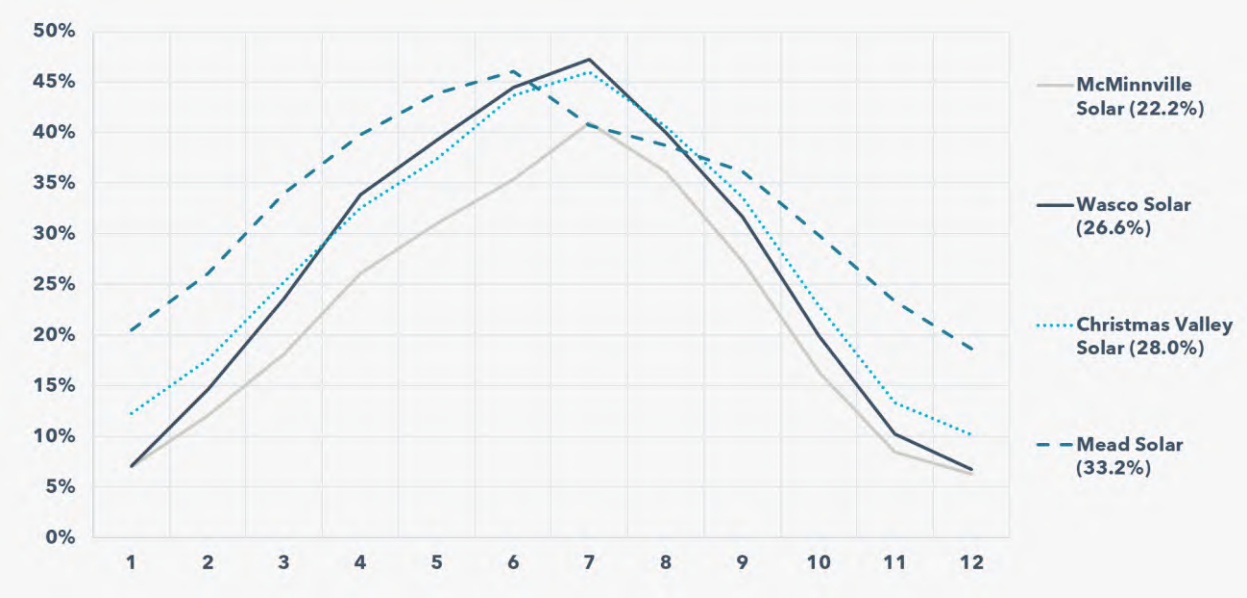
[218] An ILR greater than 1.0 means that the DC capacity of the solar array is greater than the AC capacity of the inverter. In such a configuration it is possible for the energy generation from the solar array to exceed the inverter rating resulting in the system output being limited to the inverter AC rating. This situation is referred to as "inverter clipping". The energy in excess of the inverter rating is lost and not delivered to load. All else being equal, as the ILR increases the quantity of clipped energy will increase.

Table 29. 2026 commercial operation date solar PV

	Christmas Valley, Oregon	Wasco, Oregon	McMinnville, Oregon	Mead, Nevada
Location (Lat., Long.)	43.25, -120.62	45.61, -120.7	45.21, -123.18	35.89, -114.98
Capacity (MWac)	75	75	75	75
Capacity Factor (%)	26.7%	25.3%	21.1%	31.6%
Inverter Loading Ratio	1.34	1.34	1.34	1.34
O/N Capital Cost ($/kW)	$1,297	$1,297	$1, 354	$1,297

Figure 57 summarizes the representative monthly average capacity factor for the three solar locations modeled:

Figure 57. Solar resources monthly capacity factor shapes



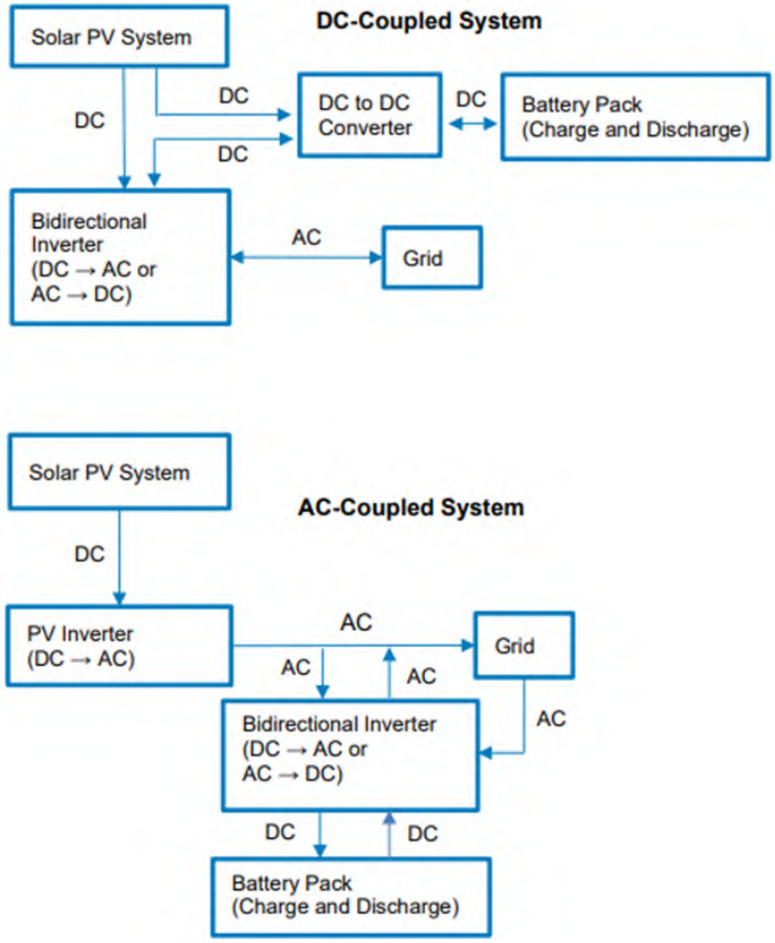
8.1.7.3 Hybrid: Solar + Storage

"Hybrid" resources pair renewable and storage resources behind a single interconnection. Hybrid resources could include solar PV with energy storage, wind with energy storage, and wind and solar PV with energy storage (such as PGE's Wheatridge Renewable Energy Facility), among others. In this 2023 IRP, PGE models solar PV with battery energy storage hybrid resources. Multiple elements are required when describing a solar + storage resource, including resource coupling (AC- or DC-coupled), solar-to-storage ratio, solar-to-inverter ratio ("inverter loading ratio" as previously described) and storage duration. Given the large number of hybrid resource permutations that would arise from investigating sensitivities around each of these elements, the IRP simplifies the analysis to include two representative solar and battery energy storage system (BESS) hybrid resources. These two hybrid resources:

- Employ a DC-coupled configuration. The solar and storage components could be coupled on the AC side of the inverters (AC-coupled) or the DC side of the inverter (DC-coupled). When AC-coupled, the battery and solar resources use separate inverters. The IRP assumption of DC coupling is consistent with the NREL ATB. **Figure 58** illustrates the essential elements of these two configurations:[219]

[219] Feldman, David, Vignesh Ramasamy, Ran Fu, Ashwin Ramdas, Jal Desai and Robert Margolis. 2021. US Solar Photovoltaic System Cost Benchmark: Q1 2020. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-77324. Available at: https://www.nrel.gov/docs/fy21osti/77324.pdf.

Figure 58. Illustrative DC- and AC-coupled solar + storage



- Differ in the ratio of solar-to-storage capacity. Similar to using ILR to summarize the solar array and inverter relationship, the solar-to-storage capacity relationship is defined in the IRP as the ratio of the storage resource capacity to the inverter rating. The two representative hybrid resources tested in this IRP are differentiated by this ratio, with one resource featuring a storage power capacity equivalent to the inverter rating (1.0) and one with a storage power capacity equal to one-half of the inverter rating (0.5).
- Use the Christmas Valley and McMinnville solar locations as discussed; however, the solar resources differ regarding the inverter loading ratio. While the standalone solar resource is modeled with an ILR of 1.34, the hybrid solar resource has an ILR of 1.50. A potential benefit of DC-coupled hybrid solar PV and BESS, since both resources are on the DC side of the inverter, is the ability of the battery to capture energy from the solar PV resource that would otherwise be "clipped" by the inverter.
- Use storage resources with a four-hour storage duration, consistent with NREL modeling assumptions.

The optimal configuration of hybrid or co-located resources will likely depend on the cost and performance characteristics of the specific resource components. This includes both the generating (wind, solar, etc.) and storage resource technologies. Prior to the passage of the IRA, energy storage resources could qualify for the investment tax credit (ITC) only when paired with a solar generating resource (and sourcing at least a minimum amount of the charge energy from that resource). As mentioned, the IRA introduced an ITC for standalone energy storage resources, removing one of the primary benefits associated with this resource configuration. However, the prevalent regional transmission constraints suggest that important benefits of co-locating renewables and storage remain.

A summary of the NREL ATB-sourced costs and parameters for the hybrid solar PV and BESS resources modeled in the IRP is provided in **Table 30**. Capital cost estimates are adjusted by geographic location based on EIA's location-based adjustment factors.

Table 30. 2026 COD solar PV and battery energy storage

	Christmas Valley Solar w/ 4 Hour Li-Ion (0.5)	Christmas Valley Solar w/ 4 Hour Li-Ion (1.0)	McMinnville Solar w/ 4 Hour Li-Ion (0.5)	McMinnville Solar w/ 4 Hour Li-Ion (1.0)
Location (Lat., Long.)	43.25, -120.62	43.25, -120.62	45.21, -123.18	45.21, -123.18
Duration (hours)	4	4	4	4
Solar ILR	1.50	1.50	1.50	1.50
Solar capacity (MWdc)	112.5	112.5	112.5	112.5
Solar capacity (MWac)	75	75	75	75
Storage capacity (MW)	37.5	75	37.5	75
Overnight (O/N) capital cost ($/kW)	$1,796	$2,297	$1,848	$2,348
O/N capital cost ($/kWh)	$449	$574	$462	$587

8.1.7.4 Offshore wind

NREL Oregon offshore wind studies are the basis for PGE's modeling of offshore wind in this IRP.[220] The NREL studies present five proxy resources distributed across the Oregon coast. For this IRP, PGE uses the southernmost of these proxy resource locations. This southern location provides the highest expected capacity factor from NREL's and PGE's modeling. This site also closely aligns with the Brookings wind energy Call Area identified for potential lease by the federal Bureau of Ocean Energy Management (BOEM).[221]

Consistent with NREL study assumptions for a 2032 commercial operation date, IRP modeling reflects 15 MW turbines with 248-meter rotor diameter and 150-meter hub height. Other modeled characteristics are summarized in **Table 31**.

Table 31. 2032 COD offshore wind

Southern Oregon	
Location (Lat., Long.)	42.69, -124.84
Capacity (MW)	960
Capacity Factor (%)	55.2%
O/N Capital Cost ($/kW)	$3,546

8.1.7.5 Geothermal

The representative geothermal resource in the IRP is modeled based on hydrothermal flash technology, as provided in the NREL ATB (Annual Technology Baseline). Given the site-specific nature of geothermal resources, the representative resource assumes a typical temperature and depth. NREL notes that costs heavily depend on these factors, requiring site-specific studies to improve accuracy.[222] These costs are summarized in **Table 32**.

[220] Musial, Walter, Patrick Duffy, Donna Heimiller and Philipp Beiter. 2021. Updated Oregon Floating Offshore Wind Cost Modeling, available at: nrel.gov/docs/fy22osti/80908.pdf.
[221] BOEM. Oregon Call Areas, available at: https://www.boem.gov/sites/default/files/images/or_callareas_april2022.jpg
[222] NREL. 2021 Electricity ATB, available at: https://atb.nrel.gov/electricity/2021/geothermal

While hydrothermal technology is relatively mature, future resource opportunities may include developing so-called enhanced geothermal systems (EGS). EGS resources differ from hydrothermal resources as they require engineering to promote the flow of underground fluids. See the additional discussion related to geothermal resources in **Section 8.5, Post-2030 resource options**.

Table 32. 2026 COD geothermal

Geothermal	
Capacity (MW)	40
O/N Capital Cost ($/kW)	$5,123

8.1.8 Energy storage resources

Two energy storage resources are included in the IRP and discussed in the following sections:

- Battery Energy Storage Systems
- Pumped-Hydro Storage

8.1.8.1 Battery Energy Storage System (NREL)

The representative battery energy storage systems (BESS) costs and performance characteristics are based on lithium-ion technology. These data are sourced from the NREL ATB for durations up to eight hours; IRP cost assumptions for longer durations apply the NREL ATB methodology of scaling the energy component costs and are derived from the same energy and power cost estimates.[223] By maintaining a representative technology assumption across durations, any analytical results between these resources are driven by the costs and benefits of the duration changes alone, not the details of their operating parameters. Costs and characteristics for the BESS resources are summarized in **Table 33**.

[223] NREL. Utility-Scale Battery Storage, available at: https://atb.nrel.gov/electricity/2021/utility-scale_battery_storage

Table 33. 2026 COD battery energy storage

	2 Hour Li-Ion	4 Hour Li-Ion	6 Hour Li-Ion	8 Hour Li-Ion	16 Hour Li-Ion	24 Hour Li-Ion
Capacity (MW)	50	50	50	50	50	50
Duration (hours)	2	4	6	8	16	24
Round-Trip Efficiency	86%	86%	86%	86%	86%	86%
O/N Capital Cost ($/kW)	$773	$1,189	$1,606	$2,022	$3,687	$5,353
O/N Capital Cost ($/kWh)	$386	$297	$268	$253	$230	$223

8.1.8.2 Pumped-Storage Hydro

The pumped-storage hydro resource is a 600 MW closed-loop system. The availability of this resource is geographically limited. Costs and performance attributes of this representative resource are based on an average of proposed regional closed-loop projects gathered from information published by the Northwest Power and Conservation Council; a summary of that information is provided in **Table 34**.[224]

Table 34. 2026 COD pumped-storage hydro

	Pumped-storage hydro
Capacity (MW)	600
Duration (hours)	10
Round-trip efficiency	80%
O/N capital cost ($/kW)	$2,912
O/N capital cost ($/kWh)	$291

[224] NW Power and Conservation Council Generating Resource Reference Plants, available at: https://www.nwcouncil.org/2021powerplan_pumped-storage_generating-resource-reference-plants/

8.1.9 GHG emitting resources

Three natural gas-fired generators are included in this IRP:

- F Class simple-cycle combustion turbine unit
- H Class combined-cycle com combustion turbine unit
- H Class combined-cycle combustion turbine unit with CO2 capture and storage
- Closed-loop biomass

Each resource is modeled with fuel supplied at a price assumed for AECO-delivered natural gas.[225] See **Section 4.5, Uncertainties in price forecasts**.

8.1.9.1 Simple-cycle combustion turbine and combined-cycle combustion turbine

The simple-cycle combustion turbine (SCCT) and combined-cycle combustion turbine (CCCT) are based on EIA's cost and performance parameter estimates. The SCCT is representative of an F-class unit. The combined-cycle combustion turbine (CCCT) resource is based on EIA's representation of a 1 x 1 H-class unit. Lifetime net capacity and heat rate are summarized in **Table 35**.

Table 35. 2026 COD SCCT and CCCT

	Simple-cycle CT	Combined-cycle CT (1 x 1)
Capacity (MW)	227	407
Heat rate	10,042	6,564
O/N capital cost ($/kW)	$830	$1,325

[225] Wood Mackenzie. "North American Power & Renewables H1 2022 Long-Term Outlook."

8.1.9.2 Combined-cycle combustion turbine with CO2 capture system

The cost and parameters for CCCT with CO2 capture system (CCS) resources are based on those produced by EIA.[226] The H-class combined-cycle unit is similar in configuration and specification to the traditional resource described previously. In addition to the CCCT, the resource includes an amine-based CO2 capture system designed to remove 90 percent of the CO2 from exhaust gases. The costs of CO2 storage are not included in the EIA cost estimates; as such, these costs are derived from Hunter to represent an estimate of the total resource cost.[227]

The configuration and auxiliary power requirements for the CO2 capture system operation result in an approximately 40 MW decrease in the net capacity of this resource relative to the CCCT without the CO2 capture previously described. Similarly, the resource is less efficient, resulting in a higher heat rate than the CCCT without CO2 capture (**Table 36**).

Table 36. 2026 COD CCCT with CO2 capture

CCCT w/ CO2 capture system	
Capacity (MW)	367
Heat rate	7,271
O/N capital cost ($/kW)	$2,720

8.1.9.3 Biomass

The biomass-fueled resource uses bubbling fluidized bed boiler technology to drive a steam turbine. Emissions controls include overfire air in the combustion process, with selective catalytic reduction and a baghouse post-combustion. The EIA AEO is the basis for resource cost and operating parameter data. Wood chips serve as the fuel in this closed-loop system. Biomass fuel prices are based on Wood Mackenzie forecasts (**Table 37**).[228]

[226] EIA AEO 2020. "Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies." Prepared by Sargent & Lundy. 93–98.
[227] Hunter *et al.*, "Techno-economic analysis of long-duration energy storage and flexible power generation technologies to support high variable renewable energy grids." Available at: https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3720769
[228] Wood Mackenzie. "North American Power & Renewables H2 2020 Long-Term Outlook."

Table 37. 2026 COD closed-loop biomass

	Biomass
Capacity (MW)	50
Heat rate	13,300
O/N capital cost ($/kW)	$7,186

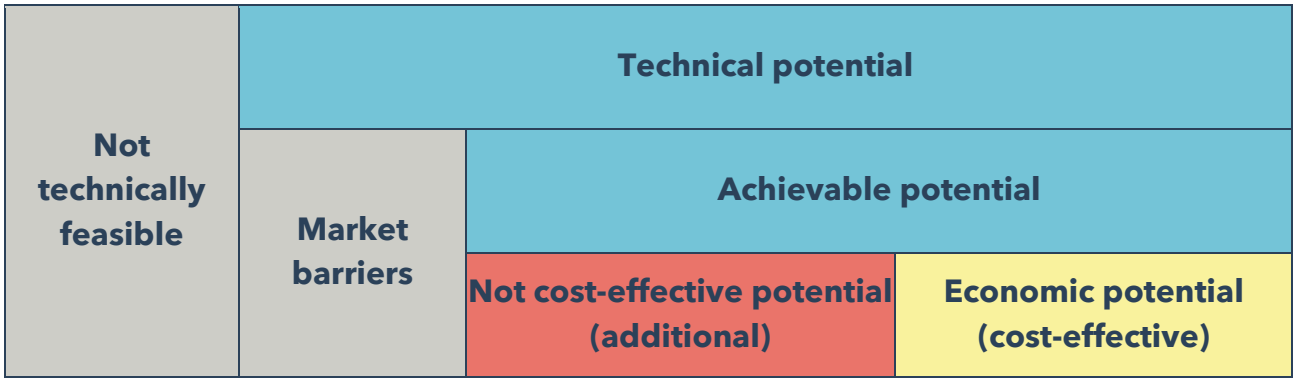
8.2 Additional distributed energy resources

In **Section 6.2, Distributed Energy Resource (DER) impact on load**, we focus on the market adoption of passive DERs (rooftop solar, transportation electrification and building electrification) and the cost-effective or economic potential, as highlighted in yellow in **Figure 59**. This IRP, like prior IRPs, includes the entire market adoption and cost-effective DERs forecast upfront when determining total load, as shown in **Section 6.3, Load scenarios**. While this process has been sufficient in the past to estimate DER impact in the IRP, the processing time between the IRP and developing the next DER potential could lead to suboptimal planning, especially in a rapidly evolving planning environment. The need to evaluate additional EE beyond cost-effective levels was also noted in Order 20-152.[229] PGE has taken steps to address this lag within resource planning by evaluating additional energy efficiency and demand response opportunities within the IRP, highlighted in red in **Figure 59**.

Additional DER or non-cost-effective DERs refer to energy efficiency and demand response technologies, measures or programs included in the Achievable Potential but were deemed non-cost-effective under the previous set of avoided costs developed for UM 1893 in 2021 and the DSP in 2022. Thus, additional DERs represent the difference between the Achievable potential and Economic potential for that DER. This is illustrated in **Figure 59**, which also highlights the relationship between the different DER potentials evaluated.

[229] *In the Matter of Portland General Electric, 2019 Integrated Resource Plan*, Docket No. LC 73, Order No. 20-152 (May 6, 2020), available at: https://apps.puc.state.or.us/orders/2020ords/20-152.pdf

Figure 59. The different potential assessments of DERs



In this IRP, we have developed a process to analyze these additional DERs previously deemed non-cost-effective through portfolio analysis. Traditionally, this is done outside of portfolio analysis using IRP inputs described in **Chapter 10, Resource economics Energy value, Capacity value, Cost of clean energy**, and **Section 10.8, Resource net cost**. Introducing the non-cost effective DERs within the portfolio has the following analytical differences:

- The IRP ELCC's method to determine capacity contribution ensures resource interactions between the DER and other resources are captured. Based on the resource's operational characteristics, this may lead to a higher or lower capacity contribution.
- The impact of transmission quality and availability significantly affects the capacity contribution and economics of supply-side options. Potential economic tradeoffs between higher fixed-cost resources, such as DERs, and avoiding additional transmission buildout, are captured within portfolio analysis.

If selected through portfolio analysis, it would provide early indications of the expected changes to upcoming avoided costs of demand response and energy efficiency, which are procured across different channels including the Energy Trust of Oregon (ETO) and PGE's demand response programs. The following sections describe the additional energy efficiency and demand response potential.

8.2.1 Additional energy efficiency

PGE worked with ETO to develop non-cost-effective or additional energy efficiency resources, leveraging the 2021 energy efficiency potential assessment to determine which list of measures did not pass the cost-effectiveness screen based on the 2021 values in UM 1893 and their associated characteristics, such as load shape, cost and expected life.

ETO provided 67 unique energy efficiency measures over the planning horizon. To optimize the modeling approach, PGE adopted a similar process as the Northwest Power and Conservation Council and aggregated energy efficiency measures into discrete bundles (or 'bins') based on the measures' levelized cost. The levelized costs are used to determine the bin size, which is the MW potential of the resources within that bin by year. Costs and design life for each bundle or bin is based on a weighted average of the measures within weighted by their megawatt average (MWa) potential. PGE also included benefits based on the UM 1893 filing,[230] by including a commensurate reduction in the fixed costs resulting from a distribution deferral credit, a regional Power Act credit of 10 percent and a risk reduction value.

Table 38 summarizes each bin for 2026, highlighting fixed costs, MWa potential and associated end uses. As the bins are developed based on levelized cost, the number and proportion of end use in each bin evolves with each year. End uses represent an aggregated set of unique measures referencing different market opportunities. For example, if we examine weatherization end uses in bins 3 and 4, we see that they contain different weatherization measures that apply to different types of buildings with different heating fuels:

- Weatherization in Bin 3 includes opportunities such as residential floor insulation, new construction manufactured housing space heating, retrofit opportunities for attic insulation and residential windows for homes heated with electricity.
- Weatherization in Bin 4 includes opportunities for residential wall insulation for homes heated with electric space heat and residential wall insulation and double pane windows in existing homes with gas heating and electric air distribution systems.

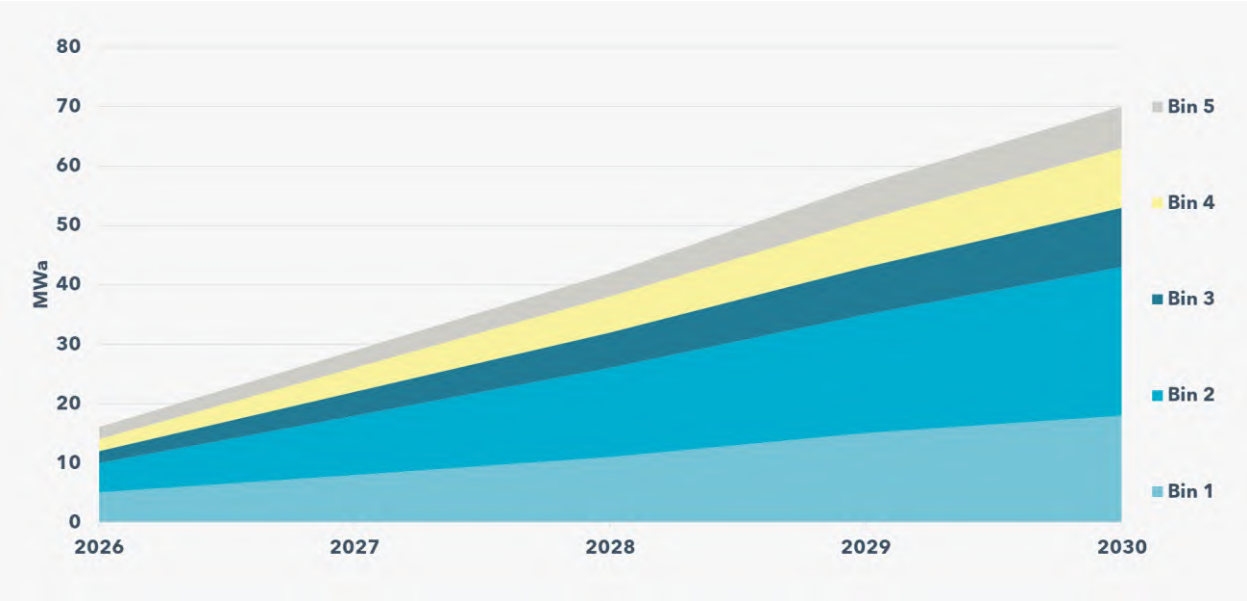
Table 38. The costs and additional potential of each EE bin in 2026

Bin	Fixed costs ($/kW-yr.)	MWa potential	End uses
1	687	5	Ventilation, lighting
2	1,486	5	Heating, weatherization, refrigeration
3	1,369	2	Lighting, weatherization
4	2,771	2	Cooling, weatherization
5	10,884	2	Weatherization

[230] PGE's updated UM 1893 avoided costs are available in ETO's presentation at the October 3, 2022 workshop, available at: https://apps.puc.state.or.us/edockets/edocs.asp?FileType=HAH&FileName=um1893hah161441.pdf&DocketID=20999&numSequence=45

Figure 60 describes the cumulative potential by bin from 2026 through 2030. While each bin has a combination of residential and commercial measures, commercial measures represent ~58 percent of the savings over the same period and residential represent the remaining ~42 percent.

Figure 60. Cumulative additional EE MWa potential through 2030



8.2.2 Additional demand response

Leveraging a similar approach for demand response as with energy efficiency, we have bundled the additional or non-cost-effective demand response programs identified by the DSP into four bundles or bins based on their dispatch characteristics and costs. **Table 39** summarizes each bin for 2026, followed by a brief description of the measures included in that bin for the year 2026.

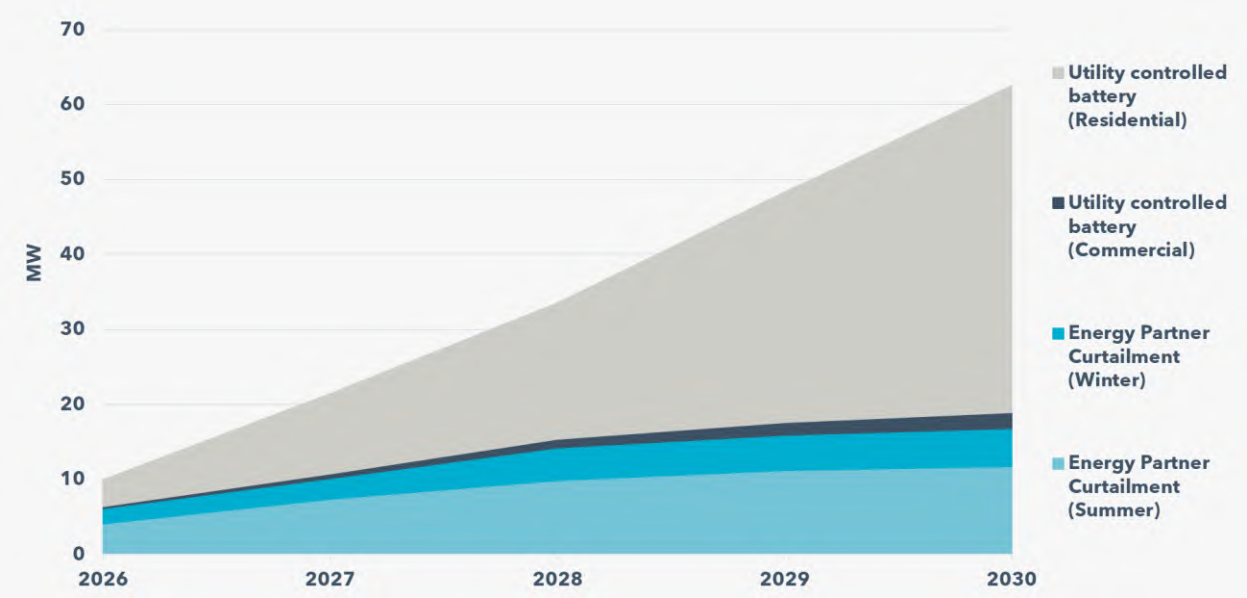
Table 39. Costs and potential of additional demand response opportunities in 2026

Measure	Fixed costs ($/kW-yr.)	MW
Energy Partner Curtailment (summer)	$499	4.1
Energy Partner Curtailment (winter)	$1,177	2.0
Utility controlled battery (commercial)	$453	0.3
Utility controlled battery (residential)	$660	3.6

- **Energy Partner Curtailment (summer and winter).** Represent the group of technologies that can deliver value within PGE's Energy Partner program, which dispatches seasonally during peak periods during weekdays and weekends.
- **Utility controlled batteries (commercial and residential).** Represents the batteries installed in partnership with customers and controlled by PGE for optimal dispatch. Optimal dispatch by PGE can offset variable power costs reducing costs for customers or can be used for reliability purposes, reducing potential market exposure risk during higher prices. PGE will conduct optimal dispatch through its VPP as described in **Section 8.4, Virtual Power Plant (VPP)**.

Figure 61 describes the cumulative potential through 2030. Residential batteries represent ~25 percent of the total MW potential.

Figure 61. Cumulative additional DR potential through 2030



8.3 Community-based renewable energy resources

Section 7.2, Community-based renewable energy (CBRE), describes the overall process PGE followed under the Community Lens Potential study. PGE identified three proxy resources for CBRE for inclusion in portfolio analysis:

- Community-scale standalone solar
- Community resiliency microgrid
- In-conduit hydropower

8.3.1 Community-scale standalone solar

PGE modeled the community-scale standalone solar proxy resource from a combination of sources. Cost assumptions were taken from the Oregon Community Solar program filing and include additional program administration and marketing costs typically associated with these resources.[231] PGE used the cost data for the "community-based carve out projects" to inform resource modeling, with an assumed efficiency factor of 20 percent cost savings from the historical baseline to account for expected economies of scale from a broader-based procurement effort.[232]

Performance features (such as capacity factor and resource shape) of the community-scale standalone solar proxy resource were modeled after a solar resource located in Boring, OR. A selection of solar PV parameter assumptions is summarized in **Table 40**.

Table 40. Performance and cost parameters of community-scale solar CBRE

Community-scale standalone solar	
Location (Lat., Long.)	45.45, -122.38
Capacity (MWac)	50
Capacity factor (%)	18.30%
Inverter loading ratio	1.2
O/N capital cost ($/kW)	$1,992

8.3.2 Community resiliency microgrid

The community resiliency microgrid CBRE proxy resource was modeled after the hybrid resources described in **Section 8.1.7.3, Hybrid: Solar + Storage**, with the solar resource component of the microgrid being the same as assumed for community-scale standalone solar described in **Section 8.3.1, Community-scale standalone solar.** Cost components, including advanced controls and islanding costs associated with the microgrid design, were used from PGE's Distribution System Plan (DSP).

The proxy microgrid resource was assumed to have a fixed ratio of solar and storage in a 2:1 ratio, such that 1 MW of storage resource was added for every 2 MW of solar PV. However, in

[231] See *In the Matter of Public Utility of Commission of Oregon, Community Solar Program Implementation*, Docket No. 1930, Staff Report for the September 21, 2021, Special Public Meeting, available here: https://edocs.puc.state.or.us/efdocs/HAU/um1930hau175534.pdf.
[232] *Id.*, Table 5 at 17, includes the upfront costs in $/kW for the carveout projects that PGE used as a starting point for analysis.

practice, the microgrid sizing and design will be location-specific and heavily dependent on the goals of the local community. For instance, system sizing decisions will differ depending on the amount and type of critical loads the microgrid supports, as well as the community preference for longer- or shorter-duration support during an outage.

PGE expects that certain projects that fall under this resource type will be eligible for federal funding opportunities under the IIJA, but because these are project-specific opportunities (as opposed to generic tax credits like the ITC), they are not reflected as a cost-reduction in IRP modeling.

8.3.3 In-conduit hydropower

The capacity factor for in-conduit hydropower resource in the IRP is modeled based on a study conducted by Oak Ridge National Lab.[233] PGE reviewed the capacity factor and other performance assumptions of the in-conduit hydropower resource and determined that it closely approximates the resource characteristics of the biomass resource described in **Section 8.1.9.3, Biomass.**

8.4 Virtual Power Plant (VPP)

Through both the DER adoption forecasts discussed in **Section 6.2, Distributed Energy Resource (DER) impact on load** and the resource options listed in **Section 8.2, Additional distributed energy resources**, and **Section 8.3, Community-based renewable energy resources**, PGE is preparing for significant growth of distributed resources. In resource adequacy calculations and portfolio analysis (discussed in **Chapter 11, Portfolio analysis**), PGE assumes that all resource types can be integrated into PGE's system and orchestrated to deliver their full potential system value. However, extending this assumption to smaller and/or behind-the-meter resources requires advancement of PGE's ability to monitor, schedule and dispatch resources in an optimized manner. To ensure realization of the full value of these resources, PGE is coordinating resource deployment and operation through a VPP.

PGE's VPP comprises DERs and flexible loads managed through a technology platform to provide grid and power operations services. The VPP will incorporate and optimize the operation of DERs and flexible loads by connecting them through the VPP platform to provide services they would not be able to provide in isolation. The VPP will be an important

[233] Oak Ridge National Lab, "An Assessment of Hydropower Potential at National Conduits" October 2022. Available at: https://info.ornl.gov/sites/publications/Files/Pub176069.pdf. Capacity factor assumptions are on page 30.

tool for identifying and extending DER and flexible load benefits to customers and communities seeking local clean energy investments.

The progression of the VPP will allow us to activate the full value of DER capabilities assumed in IRP modeling. Over time, the number of VPP operations will grow from 139 events in 2022 to many thousands and eventually millions as we go from discrete event operation to real-time energy management. Resource orchestration will be managed by a VPP technology platform, which will provide real-time visibility and control of generation, flexible loads and batteries residing within the distribution network.

VPP implementation will provide analytics that can support improved accuracy of DER and flexible load modeling in IRP analysis, as well as program cost-effectiveness evaluation and DER acquisition actions.

8.5 Post-2030 resource options

In **Chapter 6, Resource needs**, the IRP discusses future resource adequacy needs. In 2040 there is a roughly 2,000 MW increase in need due to natural gas fueled power plants no longer being available to meet retail load.[234] As a result of this need, and earlier capacity and renewable needs, most portfolios require over 3,000 MW of transmission expansion and/or generic GHG free dispatchable resources.

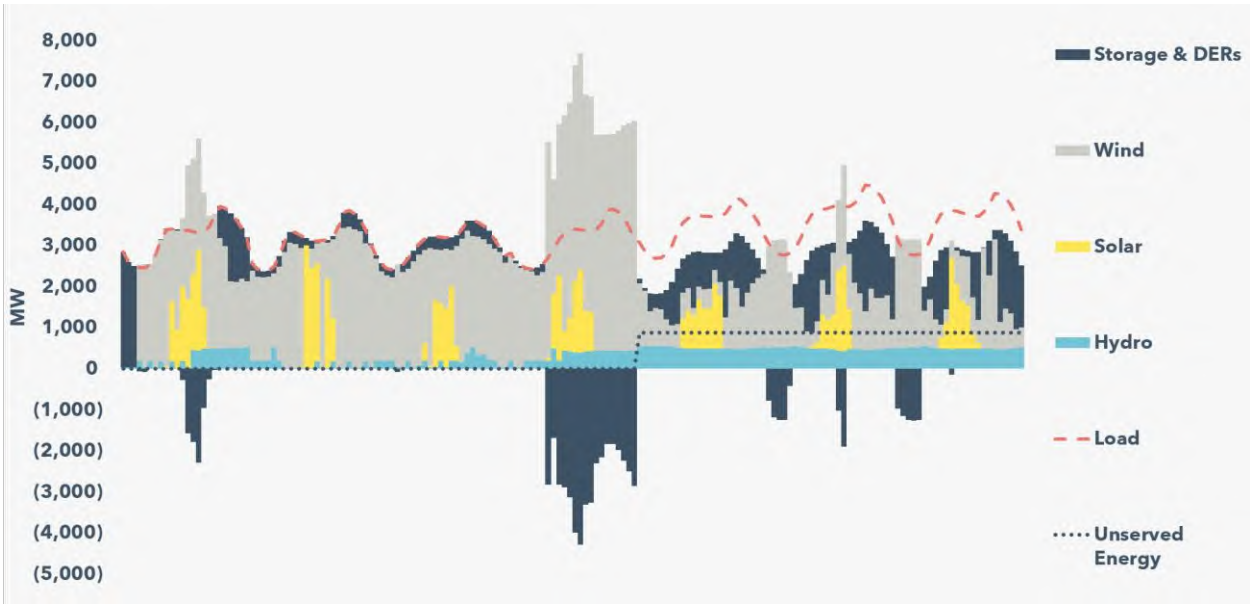
To test what happens if the assumed transmission expansion options and generic non-emitting resource are not available after 2030, PGE simulated an example power system in year 2040 with existing supply-side options available. In this example system, 6,000 MW nameplate of Northwest located wind, 6,000 MW of Northwest located solar and 6,000 MW of storage are added to the system in addition to existing resources (GHG emitting resources, like natural gas power plants, are not available in 2040 for meeting Oregon retail load). Despite adding 18,000 MW of new resource, the system still has adequacy challenges, particularly during winter days of low wind and solar generation.

A one-week example of these adequacy challenges is shown in **Figure 62**.[235] In this example, the model starts the week resource adequate, but in the last three days no longer has enough energy to meet load. Energy stored in the batteries is exhausted and there is not enough wind and solar generation available to recharge the storage and/or meet load (storage recharging is shown in the graph in negative values). The lack of energy is due to a multiday period in which both wind and solar locations in the Northwest are unproductive

[234] In 2040, per HB 2021, PGE must serve retail load with 100 percent non-emitting power. This 2040 increase in capacity needs could be reduced if the existing natural gas plants were converted to use an alternate GHG fuel source.
[235] This study was run with an earlier (spring 2022) version of Sequoia.

due to a lack of wind (reducing wind generation) and shorter winter daylight hours combined with cloud cover (reducing solar generation).

Figure 62. Example week in 2040 with only Northwest resources



As discussed earlier, the Northwest located resources provide insufficient diversity to always ensure power generation. This highlights the need for alternative resources and/or expanded transmission networks, from a geographic and/or technological perspective, to achieve longer-term GHG emission reductions while maintaining reliability. This section provides a summary of potential future resource options that PGE has considered in the 2023 IRP beyond transmission expansion to other regions.[236]

8.5.1 Hydrogen and ammonia

Hydrogen's high energy content makes it useful as an energy carrier and fuel source. On Earth, hydrogen exists naturally only in compound form with other elements, the most common being water (H_2O). Hydrogen and oxygen molecules in H_2O can be separated from one another using a process called electrolysis.[237] Hydrogen gas is combustible and it releases no CO2 when burned, which means it can provide an emissions-free fuel source.[238]

[236] While many of these resources are not included in IRP portfolio modeling, PGE may explore them in greater depth in future planning work. PGE may also explore other resource options not discussed in this section/IRP.
[237] Hydrogen production via electrolysis is done using equipment called an electrolyzer.
[238] When produced in an emissions-free manner.

One of the biggest challenges of achieving a fully decarbonized electricity system is the need for generating resources that are dispatchable, flexible and available for long durations. This is a role that is currently filled primarily with natural gas plants in today's system. Similar to natural gas, hydrogen can be used as fuel in combustion-based dispatchable electricity generating facilities, making it well-suited to providing these types of services in a decarbonized system. Hydrogen gas can be stored for long durations and used to generate power when needed, making it a complementary technology on a system with large buildouts of VERs. In such a system, electrolyzers could be powered by excess renewable energy in times of oversupply, producing hydrogen than can be stored for long durations and used to generate power when needed.

Hydrogen fuel can be used in power plants built specifically to run on hydrogen or in existing natural gas generating facilities with turbines that have been retrofitted with combustors designed to handle hydrogen fuel. Depending on the combustor technology used, appropriately equipped plants can use a fuel blend ranging from 0 percent to 100 percent hydrogen. PGE has over 1,800 MW of existing natural gas plants that could continue to provide dispatchable capacity in a fully decarbonized system if retrofitted to run on 100 percent hydrogen fuel. This represents substantial amounts of emission-free dispatchable capacity, with larger amounts possible through purpose-built facilities. Electricity generation in combustion-based power plants is far from a novel technology and while there are costs associated with retrofit, this part of the hydrogen electricity pathway is unlikely to present substantial development challenges or to be the main driver of development costs of this technology.

The largest costs and development challenges associated with this potential option for decarbonizing PGE's system are likely to be associated with development of hydrogen production, transportation and storage infrastructure. Transportation and storage infrastructure are likely to have large costs and long project lead-times, with hydrogen's low energy content by volume presenting storage and transportation challenges because of the large volumes required relative to natural gas. However, issues caused by hydrogen's low energy content by volume can be mitigated by conversion into ammonia, which has higher energy density and can be used as fuel in a similar manner as hydrogen. The production of hydrogen also has substantial capital costs associated with electrolyzers and variable costs of power used to drive the energy-intensive electrolysis process. Declines in these costs through technological innovation and economies of scale in manufacturing of electrolyzers and high penetration of VERs on the grid that lower power costs will be important developments needed to lower the barriers to hydrogen development.

Opportunities for government funding aimed at supporting the development of hydrogen production and transportation infrastructure could substantially lower the barriers to hydrogen playing a role in decarbonizing PGE's system. For example, in June of 2022, the US Department of Energy (US DOE) announced an $8 billion program associated with the

Bipartisan Infrastructure Law to fund the development of regional clean hydrogen hubs.[239] Additionally, the Inflation Reduction Act of 2022 (IRA) created clean energy tax credits, similar to those that have contributed to unprecedented development of wind and solar over the past decade, that apply to clean hydrogen production.[240]

8.5.2 Nuclear

Nuclear power is a mature technology, with the first commercial power generating reactors coming online in the 1950s, and hundreds of operating reactors around the world. Nuclear power provides both baseload capacity and non-emitting energy to the power system.

Although nuclear power has many positive characteristics, like non-emitting baseload generation, traditional large nuclear reactors also have hurdles to overcome. Nuclear power safety accidents, while rare, can be catastrophic and are often followed by public and political pushback on the technology. Recent large reactor nuclear builds in the US, like Vogtle units 3 & 4, have seen construction cost overruns and timeline delays (both units are currently in testing, with Unit 3 recently achieving criticality and expected in-service in Q2 2023).[241] Additionally, in Oregon, Measure 7 prohibits the construction of a new nuclear power plant in Oregon without a federal long-term nuclear waste repository and a statewide popular vote. Public dislike of nuclear power, largely due to safety concerns, led to multiple ballot measures in Oregon aimed at closing Trojan, a nuclear power plant operated by PGE that closed in 1992.[242] Oregon law does not prohibit PGE from purchasing nuclear power produced in a nearby state, subject to standard prudency review.

There is optimism that new generation nuclear plants will be competitive in the electric power landscape and reduce safety and political concerns of more traditional designs. UAMPS, a collective of smaller utilities in the US West, is planning to build a small modular reactor nuclear power plant. The project reactor design recently received US Nuclear Regulatory Commission certification (a first for Small Modular Reactor designs).[243] The reactor design has passive safety features, including being able to shut down and cool without operator action or power.[244] In their 2021 IRP, PacifiCorp identified a 500 MW sodium cooled fast reactor nuclear power plant with molten salt storage to come online in 2028.

[239] Available at: https://www.energy.gov/articles/doe-launches-bipartisan-infrastructure-laws-8-billion-program-clean-hydrogen-hubs-across
[240] Available at: https://www.energy.gov/eere/fuelcells/financial-incentives-hydrogen-and-fuel-cell-projects
[241] Vogtle 3 & 4 were initially estimated to cost around 14 billion, more recent estimates are over 30 billion.
[242] The ballot measures failed; Trojan closed early in 1992 due to repair costs following a maintenance check.
[243] Available at: https://www.energy.gov/ne/articles/nrc-certifies-first-us-small-modular-reactor-design.
[244] Available at: https://www.nuscalepower.com/en/products/voygr-smr-plants.

Both the UAMPS and PacifiCorp nuclear projects have not begun construction. It remains to be seen if next generation nuclear technology can lower the cost, safety and political hurdles faced by traditional nuclear power. If it can, nuclear power could play a role in replacing existing dispatchable GHG emitting generation with non-emitting power that has similar characteristics.

8.5.3 Geothermal

Geothermal energy is the heat contained in the Earth's interior. Electricity generation from geothermal resources is generally achieved by the recovery of heat in the form of hot water or steam accessed via injection and production wells drilled into the Earth. Resources are broadly categorized as either hydrothermal or enhanced geothermal systems (EGS) depending on the characteristics of the groundwater and subsurface rock structure.[245] Geothermal resources are non-emitting and are expected to operate at an 80-90 percent capacity factor.

The US Geological Survey estimates nine gigawatts (GW) of electrical generation capacity are available from identified hydrothermal resources in the US.[246,247] Of this, approximately 3.5 GW have been developed, all in the WECC (except for the Puna plant in Hawaii).[248] An additional 30 GW may be present in favorable, yet undiscovered, hydrothermal resources. Over 95 percent of regional geothermal capacity is in California and Nevada. Roughly 30 percent of California's geothermal capacity is at Calpine's nearly 700 MW The Geysers project north of Santa Rosa.

The hydrothermal potential (discovered and undiscovered) in Oregon is estimated to be 2.4 GW. EGS development in Oregon could support electrical generation capacity of more than 60 GW. The only commercial geothermal project currently operating in Oregon is the Neal Hot Springs plant near Vale in eastern Oregon. The nearly 30 MW project, which began operation in 2012, is jointly owned by Ormat and Enbridge with Idaho Power as the off taker.[249]

[245] Hydrothermal resources are those where the naturally occurring rock structure and groundwater flow are sufficient to support energy recovery. EGS resources have sufficient heat but lack either the groundwater or rock structure to allow for efficient energy recovery, thus requiring the use of engineering techniques to introduce liquid or allow for the flow of liquid within the rock structure.
[246] USGS. "Assessment of Moderate- and High-Temperature Geothermal Resources of the United States." Menlo Park, CA: US Geological Survey, 2008. Available at: https://pubs.usgs.gov/fs/2008/3082/pdf/fs2008-3082.pdf.
[247] NREL. 2021 Electricity ATB, available at: https://atb.nrel.gov/electricity/2021/geothermal.
[248] S&P Global Market Intelligence.
[249] S&P Global Market Intelligence.

An EGS demonstration project at Newberry Volcano (southeast of Bend, Oregon) is being developed.[250] The developer reports that commercial deployment of EGS technology at this site may be possible by 2030.[251] The approximately 3 MW Paisley Geothermal plant in Lake County, Oregon, is out of service per EIA reporting.

Factors that may restrict the development of geothermal resources include:[252]

- Difficulties in locating new resources (undiscovered);
- Technological challenges related to the development of and production from EGS resources over relatively long periods of time;
- Issues surrounding permitting, land access and environmental reviews may extend project development timelines;
- The general constraints to availability of transmission capacity discussed elsewhere in this IRP may apply to this resource site.

Future improvements in drilling technologies will result in reduced development time and costs. Developments in EGS stimulation technology and higher success rates will also reduce costs and development timelines.[253]

8.5.4 Renewable natural gas

Renewable natural gas (RNG) is a fuel derived from biogenic and other renewable sources that offers the potential of use within existing natural gas pipelines. Today RNG is commonly produced from waste streams found in landfills, wastewater treatment plants and animal manure. The American Gas Foundation estimates that under a high resource potential scenario the US could produce more than 4,500 trillion British thermal units (BTU) of renewable natural gas by 2040, which can serve 93 percent of current average residential gas usage nationally (the low resource potential study found roughly 60 percent less RNG available by 2040).[254] Oregon's DOE found nearly 50 billion cubic feet of potential renewable natural gas sources in Oregon, enough to replace around 20 percent of the state's current

[250] Available at: https://www.energy.gov/eere/geothermal/enhanced-geothermal-systems-demonstration-projects
[251] Available at: https://www.businesswire.com/news/home/20210923005253/en/AltaRock-Energy-Initiates-Development-of-First-SuperHot-Rock-Geothermal-Resource
[252] USGS. "Assessment of Moderate- and High-Temperature Geothermal Resources of the United States." Menlo Park, CA: US Geological Survey, 2008. Available at: https://pubs.usgs.gov/fs/2008/3082/pdf/fs2008-3082.pdf.
[253] NREL. 2021 Electricity ATB, available at: https://atb.nrel.gov/electricity/2021/geothermal
[254] American Gas Foundation, "Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment," 2019.

gas usage (this represents 10 billion cubic feet from biogenic sources and an additional 40 billion from thermal gasification, which currently faces technical obstacles).[255]

The integration of RNG into PGE's existing plants could potentially provide PGE a means to retain thermal generation at lower or zero GHG emissions. This would provide dispatchable capacity for periods of low renewable generation and/or elevated demand. However, there is uncertainty around if RNG will be considered GHG emissions free.[256] If GHG emissions are attributed to RNG usage it then becomes a bridge solution that could reduce emissions between 2023-2039.

RNG is not currently a scalable option for PGE due to its limited supply. While the ODOE has estimated that biogas could offset roughly 20 percent of the state's current natural gas use, there currently are only a few facilities that generate RNG. An economic push due to higher natural gas prices and the effect of directed state, local and federal policies could potentially increase both the number of RNG facilities and the quantities they produce.

8.5.5 Long-duration energy storage

Long-duration energy storage (LDES) is defined as any electricity storage with greater than six hours of duration. These storage options perform the same function as those described earlier in **Sections 9.1.8, Energy storage resources,** however their extended durations allow them to provide supply over longer times of need. This provides a better ability to maintain resource adequacy in larger times of system stress, and IRP modeling has demonstrated a more effective capacity per MW than shorter duration storage.[257] This section describes the wide variety of long duration storage technologies being developed.

Chemical energy storage resources convert electrical energy into an intermediate state and back using a chemical process. Currently lithium-ion batteries are the most common storage options on the market and are discussed in detail in **Chapter 11, Resource Economics**. Other chemical storage options include flow batteries. Longer duration batteries may soon be more widely available. For example, Great River Energy, a Minnesota Utility, is working to develop a multiday iron air battery.[258] Hydrogen storage is another long duration chemical storage option (discussed earlier in this section). Power can also be stored by converting electricity into potential energy with physical work, then reversing that process to discharge

[255] Oregon Department of Energy, Biogas and Renewable Natural Gas Inventory SB 334 (2017) – 2018 Report to the Oregon Legislature, available at: https://www.oregon.gov/energy/Data-and-Reports/Documents/2018-RNG-Inventory-Report.pdf
[256] The California Air Resources Board (CARB) shows the Carbon Intensity Values of Certified Pathways of Bio-CNG (RNG) as being significantly less than LNG and CNG (geological natural gas). The Carbon Intensity Values of Certified Pathways table was last updated on December 30, 2022. LCFS Pathway Certified Carbon Intensities | California Air Resources Board.
[257] See **Appendix J, ELCC sensitivities** for more detail
[258] https://greatriverenergy.com/company-news/battery-project-includes-minnesota-flair/

back to the grid. This process of mechanical energy storage includes pumped storage hydro, compressed air storage and other storage technologies.

Thermal energy storage converts electricity into heat, stores the heat in a medium and then converts it back into electricity. For example, concentrating solar power often uses molten salt for energy storage.[259]

As more variable energy resources are expected to arrive on both the PGE system and the greater Western Interconnection, there may be increased opportunities to use storage to shift energy from oversupply hours to hours of greater need/value. Forecasted oversupply trends are discussed in IRP **Appendix N, Renewable curtailment**. PGE will continue to track trends in long duration storage and evaluate how new products can potentially bring value to the power system.

8.5.6 Carbon capture, utilization and storage

Carbon capture, utilization and storage (CCUS) is the process of capturing CO2 emissions produced by the combustion of fossil fuels so it can be stored or used in downstream processes. CO2 emissions can be captured through a process in which CO2 is separated from other gases by chemical absorption or physical separation during the power generation process. This is done using equipment that employs chemical "scrubbers" that bind to CO2 molecules, capturing them before they are released into the atmosphere. Such equipment can be installed on existing or new power plants. Once captured, the CO2 can be compressed and then stored or sequestered in underground geologic formations or utilized as a feedstock in downstream industrial applications.

CCUS could help PGE achieve a reliable decarbonized system by allowing existing or new natural gas plants to serve as non-emitting dispatchable resources. As noted previously with regards to hydrogen, PGE's over 1,800 MW of existing natural gas fired power plants represent a substantial amount of dispatchable capacity if retrofitted to become non-emitting resources.

The most substantial barriers to the use of CCUS as a tool for decarbonizing PGE's system are costs and technological maturity. CCUS costs are high relative to other technologies and globally there is currently only one operational commercial power plant equipped with CCUS (Boundary Dam coal plant, Canada)[260] after the other that existed was shut down due to persistent mechanical failures.[261] The ability of CCUS systems to convert fossil fuel plants to

[259] https://www.energy.gov/sites/default/files/2018/09/f55/Concentrating-Solar-Thermal-Power-FactSheet.pdf
[260] Boundary Dam Carbon Capture Project (saskpower.com)
[261] https://www.reuters.com/article/us-usa-energy-carbon-capture/problems-plagued-u-s-co2-capture-project-before-shutdown-document-idUSKCN2523K8

completely non-emitting is unproven and most CCUS projects today target 90 percent capture of emissions.[262] In order for CCUS to play a role on PGE's system beyond 2040, the technology would need to be able to capture 100 percent of emissions.

Substantial opportunities for government funding have the potential to both advance the technological development and reduce costs of CCUS. There is a federal tax credit for $50/MT of captured CO2 that is geologically stored and $35/MT if the CO2 is used as opposed to stored.[263] Additionally, the Bipartisan Infrastructure Bill appropriates significant funding for the development of CCUS, including: $3.5 billion for a Carbon Capture Technology program and CCUS large-scale projects over the next five years; $3.5 billion for four regional direct air capture (DAC) hubs. $2.5 billion for a ODOE carbon storage program; and establishment of a new Carbon Dioxide Transportation Infrastructure Finance and Innovation (CIFIA) program to provide $2.1 billion in low-interest loans to large CO2 pipeline projects (up to 80 percent of costs).[264]

8.5.7 Regional integration

A regional market administered through a Regional Transmission Organization (RTO), or an Independent System Operator (ISO) provides several key functions that can yield regional benefits. Key regional benefits that can help address the adequacy needs of 2040 include:

- **Common resource adequacy standards** across the region enable the opportunity to share capacity and capture regional diversity across a larger geographical footprint enabling reduction in planning reserve margins which reduce overall resource need.
- **Shared transmission planning** allows resource planning to inform transmission planning and vice versa. This broadens the set of capacity expansion alternatives that can reduce the overall size (nameplate MW) of the system needed to meet system needs. Additionally, shared transmission planning through an organized market yields governance benefits that can assist with cost and benefit allocation conflicts. This in turn increases the likelihood of successful construction and commissioning of a transmission project. Lastly, with shared transmission planning spanning a larger footprint of customers, the risk per customer is lowered.
- **A single market operator** can dispatch resources more efficiently and at lower production costs while optimizing use of transmission capacity, a key constraint within the region.

[262] https://climate.mit.edu/ask-mit/how-efficient-carbon-capture-and-storage#:~:text=CCUS%20projects%20typically%20target%2090,will%20be%20captured%20and%20stored.
[263] The Tax Credit for Carbon Sequestration (Section 45Q) (fas.org)
[264] Bipartisan Infrastructure Bill Invests Billions in CCUS | Holland & Hart LLP - JDSupra

Today, PGE is part of or interested in multiple voluntary regional programs ranging from short-term capacity or resource adequacy programs such as the Western Resource Adequacy Program (WRAP) to real-time or energy imbalance programs such as the Western Energy Imbalance Market (EIM). These programs are focused on short-term market operations and are commonly designed to unlock key operational benefits such as price arbitrage, load diversity, improved visibility, reduced area control error etc. While these benefits are critical, they are usually unable to support long-term reliability planning needs. Consequently, these programs, given their current structure, are unable to address the 2040 needs highlighted earlier.

For this IRP, PGE described the Western Resource Adequacy Program (WRAP) in **Section 11.1.2, Resource adequacy**, including program details, benefits and its applicability in this and future IRPs. Additionally, PGE has also modeled a portfolio that explores the benefits of participating in an organized market by 2030. This is further detailed in **Section 11.4.7, Emerging technology portfolios.**

8.5.8 Coastal generation

There are several coastal energy technologies that could become commercially available inside the IRP planning horizon. In Oregon the PacWave South test bed is under development to evaluate different wave energy technologies and eyeing a 2025 online date.[265] The test bed will allow for various types of wave energy technologies to be evaluated. PGE will continue to follow the development of wave and other coastal technologies as they mature. Offshore wind, another coastal energy technology, is discussed in **Section 8.1, Utility-scale energy resources**.

8.6 Utility versus third-party ownership

The following section addresses the requirements outlined in IRP Guideline 13 of the Public Utility Commission of Oregon (OPUC or the Commission) Order No. 07-002 by providing a high-level discussion of the advantages and disadvantages of owning a resource instead of purchasing power from another party. This discussion, however, is not intended as specific recommendations for the IRP portfolio modeling or Action Plan process.

In this IRP, procurement action plans are designed to use technology-neutral procurement processes to allow PGE to pursue resources with the key attributes identified in the Preferred Portfolio. However, PGE does not procure the specific resource types in amounts set forth in the Preferred Portfolio. Instead, PGE preserves the flexibility to pursue various technologies

[265] https://today.oregonstate.edu/news/osu-led-wave-energy-testing-facility-reaches-key-construction-milestones

and resource locations that may deliver maximum value to customers. With dynamic technology development and pricing changes, we continue to be open to opportunities that would secure lower cost from projects bid into a Request for Proposals (RFP) that may diverge from the modeled technologies in the IRP Preferred Portfolio.

8.6.1 Benefits of utility resource ownership

Utility-owned resources provide multifaceted advantages to customers, including resource control, long-term access, fleet efficiency, physical and digital security integration, cost-of-service rate making benefits and reduced exposure to counterparty performance.

8.6.1.1 Operational autonomy

Customers benefit from utility-owned resources when utilities elect to change operations, determine maintenance practices, implement system upgrades or make any other decision that advances customers' best interests. When resources are under contract with a third-party, a utility's ability to make changes to third-party owned resources are generally restricted. Therefore, a utility is generally prevented from making any operational change at a third-party owned resource, regardless of the customer benefit associated with such a change.

8.6.1.2 Long-term access

Customers also benefit from reduced customer costs and risks when a utility decides to extend the operating life of a utility-owned asset. Direct ownership of a utility-owned resource provides long-term access to the asset and associated resource potential since the utility has prioritized rights to the site in addition to the holding of necessary permits, transmission rights and interconnection rights.

8.6.1.3 Alignment among owned resources

Operating utility-owned resources also provides utilities with the ability to design co-location resources to fit customer needs. Port Westward Unit 2 is an example of a co-location design decision where PGE was able to augment existing resource locations to cost save for customers while adding capacity to meet needs. Port Westward Unit 2 was put in the existing Port Westward site, where operations and maintenance are shared among resources. In doing so, the usable life of the site was extended, and fixed cost was reduced.

8.6.2 Risks of utility resource ownership

Utility resource ownership may come with the risk of production underperformance. Another risk of utility resource ownership is the significant increase in revenue requirement at the beginning of the resource's useful life and having this substantial cost increase impact customer prices.

Owning a resource also imposes on the utility the responsibility to deliver and integrate the resource to the power grid.

8.6.3 Benefits of third-party ownership

When a utility enters a contract with a power producing third-party, the project risk of the power plant is shared by both parties. In general, the terms of the agreement allocate some of the risks associated with construction of the project to the power producing third party. The reduced risk for the utility reduces the risk passed onto customers.

8.6.4 Risks of third-party ownership

There are contractual and operational risks associated with third party-owned resources. A utility is locked into specific contract arrangements for the duration of the contract, usually twenty to thirty years. Such long-duration commitments can introduce operational, market or regulatory compliance risks.

8.6.5 Resource ownership considerations

In general, PGE intends to engage in RFP processes that adhere to the competitive bidding rules to assess the resource ownership structure that will best serve customers from a delivery, cost and environmental standpoint. In the upcoming RFP, PGE is contemplating submitting a benchmark to encourage competitive bidding and solicitations from a wide range of resource technologies and structures that will provide the best value for customers. PGE is evolving the RFP process to objectively weigh the benefits and risks of the various ownership structures during the RFP process to make the best decisions about resource ownership for customers.

Note that in evaluating projects from an RFP process, each project is assessed using project-specific characteristics such as project development maturity, resource performance, resource pricing and counterparty capability. This level of detail is unique to the RFP selection process and does not apply to proxy resources included in the IRP evaluation. Proxy resources are designed to represent technology options rather than specific projects.

Chapter 9. Transmission

Portland General Electric (PGE) owns transmission assets and rights to ensure reliable delivery of electricity from generation resources to load. Many of the future resources PGE will acquire to decarbonize and maintain adequacy require additional transmission rights. However, there is a limited amount of existing transmission available for future resources to use. This chapter discusses today's transmission system, introduces the concept of transmission proxies to represent new transmission options in IRP modeling and identifies transmission projects that can be part of the IRP's Action Plan.

Chapter highlights

- PGE's unique footprint necessitates collaborative planning with Bonneville Power Administration (BPA) and regional peers to deliver resources to PGE's service area and to serve load within PGE's footprint. Transmission planning and development often takes longer than the Integrated Resource Plan (IRP) action window time horizon, necessitating early proactive efforts.
- As PGE plans to meet House Bill (HB) 2021's decarbonization targets, it is necessary to proactively mitigate transmission constraints to ensure reliable service of current and future load.
- Portfolio analysis in this IRP indicates additional transmission need on PGE's system, across BPA's system and in additional climate zones.
- PGE proposes addressing transmission need through a combination of rights and/or projects to alleviate congestion across the South of Allston flowgate, expanding transmission to reach additional climate zones that provide resource diversity, and increasing PGE's ability to import electricity through the study of upgrading the Bethel to Round Butte line from 230 to 500 kV.

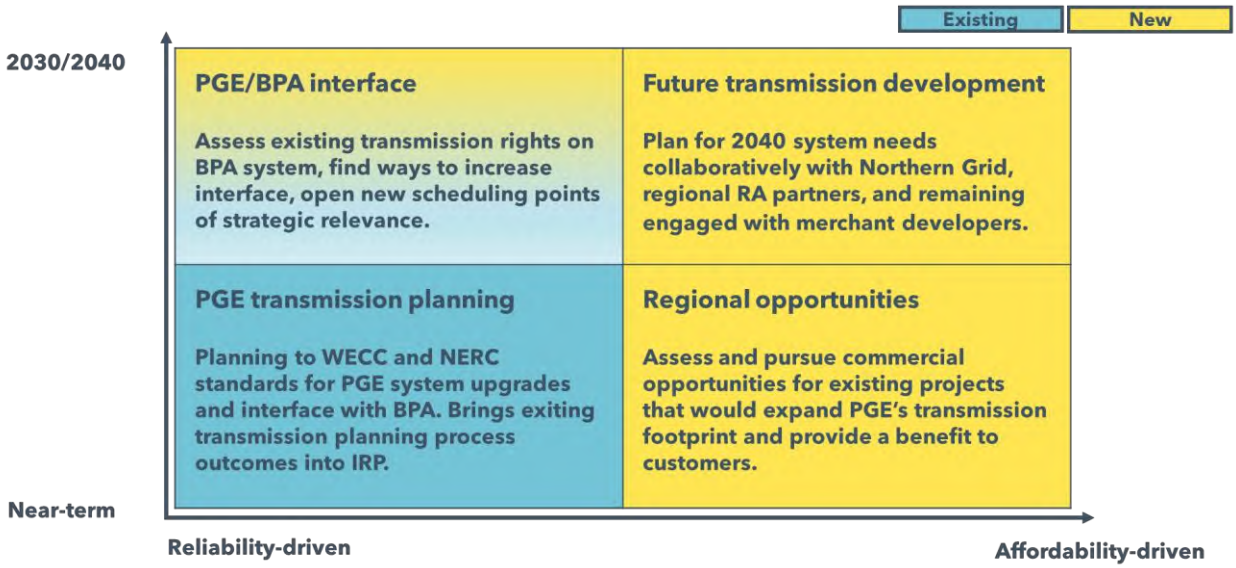
9.1 Introduction to transmission environment and impact on resource strategy

PGE's transmission portfolio – comprised of PGE-owned assets and transmission rights held on other networks – is designed to ensure reliable delivery of electricity from a broad array of generation resources to load. As PGE works toward the decarbonization goals of HB 2021, PGE will likely need to explore adding Variable Energy Resources ("VERs") that are non-

emitting electricity from new geographic areas within the backdrop of growing interconnectedness in the west. As PGE's system evolves to meet decarbonization goals reliably, we will need to evolve our transmission portfolio to expand our reach throughout the West and strengthen our ability to serve locally.

PGE's analysis in this IRP illustrates that the optimal portfolio balance of cost and risk includes holistic transmission investment over the next decade: through continued and expanded planning on PGE's system, through alleviating congestion on BPA's system, through regional opportunities to expand PGE's historic geographic transmission footprint and through robust planning for 2040 needs. This combination of transmission additions will provide reliable service as we add generating resources in Oregon and will supplement resources close to home by providing access to climate zones with higher and diversified wind and solar production. The transmission investment introduced in this chapter and recommended for acknowledgment through portfolio analysis balances cost, risk and a continual progress toward decarbonization targets (**Figure 63**).

Figure 63. PGE holistic transmission approach



The transmission system that serves PGE customers is highly integrated with other transmission systems in the West. It provides the critical infrastructure needed to serve customers in Oregon's largest metropolitan areas and enables economic development within the state.

PGE Transmission assets: As a vertically integrated investor-owned utility that is regulated by the Federal Energy Regulatory Commission (FERC), PGE is obligated by FERC to functionally separate its Transmission Function (PGET) from its Marketing function (PGEM). PGET is required to plan and operate PGE's transmission system in a non-discriminatory manner that provides open access to all transmission customers, including PGEM. Put plainly;

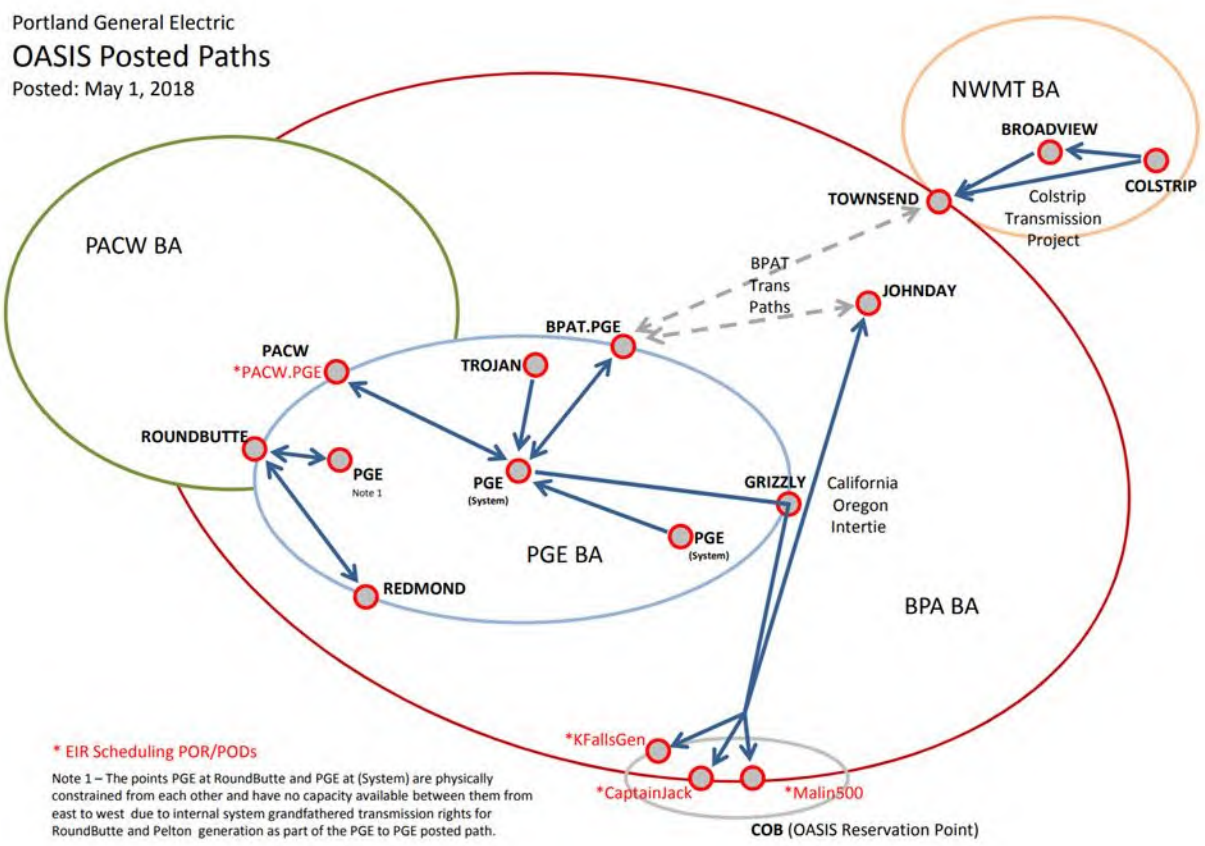
this means PGET cannot unduly preference PGEM and, by extension, the retail customers that PGE serves. PGET's transmission customers include PGEM, Oregon-defined Electricity Service Supplier (ESS) customers, BPA and transmission customers who utilize PGE's transmission system to move power across the region.

PGE merchant portfolio: PGEM is responsible for purchasing transmission rights – on PGE's transmission facilities and those of other regional providers – to deliver power to PGE's service area to meet PGE's load obligations. PGEM holds extensive rights on the BPA transmission system, the largest in the Pacific Northwest. PGE is also interconnected to the western part of PacifiCorp's system, albeit with a much smaller transfer capability than PGE's interface with BPA. PGE's interface with PacifiCorp is primarily used to meet obligations within the Energy Imbalance Market (EIM). PGE is a co-owner of the Colstrip Transmission System, a 500 kV transmission line in Montana that runs between Colstrip and BPA's system in western Montana. Additionally, PGE co-owns one of the three 500 kV circuits in central Oregon that comprise the Northwest AC Intertie (NWACI) and connects Oregon to California. PGE jointly owns NWACI with BPA and PacifiCorp and it is operated by BPA.

Planning and regional opportunities: PGE is a member of NorthernGrid, the transmission planning organization that plans the transmission system used to serve the majority of the Pacific NW and Intermountain states of the western US.

PGE is uniquely situated, with load in the northern Willamette Valley served by PGE's physical transmission system (PGET) that exists largely surrounded by, and significantly dependent on, BPA's transmission system, as shown in **Figure 64**.

Figure 64. PGE transmission and interconnection to BPA, PACW and Northwestern



9.1.1 PGE transmission to serve load

The decarbonization requirements of Oregon HB 2021 direct load serving entities including PGE to reduce greenhouse gas emissions associated with serving Oregon retail electricity consumers, compared to baseline emissions levels by 80 percent by 2030, 90 percent by 2035 and 100 percent by 2040. PGE currently estimates that compliance with this decarbonization standard will require significant addition of resources to serve load in compliance with state law. As mentioned in **Section 6.5, Energy need,** and **Section 6.6, Capacity need**, this IRP has identified a need for 905 megawatt average (MWa) of GHG-free energy and 1136 megawatts (MW) of summer capacity to reach the 2030 target and maintain system adequacy. It is important to recognize that as economic development-driven load growth happens, there may be pockets that contain high concentrations of load within PGE's service area. To reliably serve this concentration of load, PGE will need to proactively develop unique transmission solution (see **Section 6.1.2.2, Industrial growth**).

PGE is considering investing in transmission solutions that would allow access to other climate zones to achieve additional resource diversity as its resources become more dependent on weather conditions to operate.

PGE is likely to meet transmission need through a combination of purchased transmission rights" or "transmission rights on other systems, investment in transmission assets currently in development regionally, and/or development and upgrade of PGE transmission assets to serve load.

As PGE selects the optimal portfolios of generating resources within this IRP to meet future load needs, PGE continues to plan for sufficient transmission to serve future load obligations reliably and comply with state law. The transmission options discussed in this chapter and recommended for acknowledgment in the Action Plan result directly from the future load-service needs associated with native load growth and HB 2021 requirements.

9.2 Regulatory environment

Consistent with the principles of FERC Order Nos. 890 and 1000, and requirements of PGE's FERC-approved Open Access Transmission Tariff (OATT), PGE is required to plan and build its transmission system to meet the needs of all PGET transmission customers, including PGEM and ESS customers.[266,267] Transmission customers typically utilize PGE's transmission system to serve load contained within PGET's system footprint or to transfer power through PGET's system to other transmission systems.

Customers who serve load located on PGE's transmission system generally use a transmission service called Network Integration Transmission Service (NITS). Transmission customers who move power through PGET's transmission system for delivery to a point on another transmission system typically use Point-to-Point (PTP) transmission service. For PGET to develop its transmission plans for most NITS customers, with the State of Oregon-defined Electric Service Supplier (ESS) customers being the exception, PGE uses the ten-year load-and-resource (L&R) forecasts supplied by NITS customers along with PTP transmission service commitments and requests. ESS customers are not obligated to designate generation resources to serve their loads.

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[266] *See* Preventing Undue Discrimination and Preference in Transmission Service, Order No. 890, 72 Fed. Reg. 12266 (Mar. 15, 2007), FERC Stats. & Regs.¶ 31241 (2007), available at: https://www.federalregister.gov/documents/2007/03/15/E7-3636/preventing-undue-discrimination-and-preference-in-transmission-service

[267] *See* Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, Order No. 1000, 76 Fed. Reg. 49842 (Aug.11, 2011), FERC Stats. & Regs. ¶ 31323 (2011), available at: https://www.federalregister.gov/documents/2011/08/11/2011-19084/transmission-planning-and-cost-allocation-by-transmission-owning-and-operating-public-utilities

PGET uses the NITS customers' L&R forecasts and best available information, including transmission service, generation interconnection requests and information from neighboring transmission providers' transmission planning and construction activities, to determine the need and timing for investments in the transmission system. The bulk of PGET's NITS customer-driven needs comes from PGEM, which supplies energy and capacity for PGE's retail customers. Oregon's HB 2021 is expected to significantly impact the resource decisions of PGET's transmission customers, including PGEM, resulting in the need to develop new transmission system investment and deployment strategies. The 2022 L&R letter from PGEM to PGET documents the expectation that PGEM's future resource needs will change, given the need to comply with HB 2021. PGET must now work with its customers, including PGEM, to plan the PGET transmission system to maintain reliable service as its customers' resource mixes change over the next several years.

While PGE's transmission customers, except ESSs, are required to provide annual L&R forecasts looking 10 years into the future, transmission development in the West requires lengthy planning, rights-of-way (ROW) acquisition, permitting and construction timelines. As such, PGET cannot rely solely on the L&R forecasts to plan future transmission investments.

9.2.1 FERC transmission planning notice of public rulemaking

At the time of writing, FERC has an open rulemaking docket that seeks to explore potential improvements to the regional transmission planning requirements.[268] In the NOPR, FERC proposes to increase the transmission planning time horizon from 10 years to a minimum of twenty, identify whether transmission planning regions should contemplate standardized needs and benefits for cost allocation, determine whether transmission planning regions should be required to identify geographic resource zones, whether FERC should reinstate the right of first refusal for incumbent transmission providers when a proposed project would run through their territory, and/or require transmission planning regions to conduct sensitivity planning analysis contemplating a prescribed number and type of specific scenarios. PGE continues to follow and participate in this rulemaking process and will make any necessary updates to its OATT to reflect changes to the transmission planning process as they are approved by FERC and implemented over the next several years.

[268] FERC Docket No. RM21-17-000.

9.2.2 PGE transmission system reliability planning requirements

The PGE service area is a compact area located primarily in Oregon's Willamette Valley. PGE owns and operates its transmission system and Balancing Authority Area (BAA) to deliver energy to PGE's retail customers while also providing transmission service to other wholesale transmission customers as required by FERC and in accordance with PGET's OATT. Most of PGE's existing, owned transmission assets are within the PGE service area. PGE also owns transmission assets in central and southern Oregon and Montana. PGE is obligated to plan, build and operate the transmission system in a manner that reliably delivers power to serve customer load and the needs of PGET's OATT transmission customers.

The PGE transmission and sub-transmission system has 1,663 miles of lines (213 miles of 500 kV, 408 miles of 230 kV, 566 miles of 115 kV and 476 miles of 57 kV sub-transmission) and includes 176 substations and switching stations.

As PGE plans for the transmission system that contemplates the increased resource need of the future, PGE's goals are:

- Reliable delivery of non-emitting energy to serve load;
- Ability to meet growing customer loads during a broad array of planned and unplanned system outage conditions;
- Adapting to the changing system conditions from economy-wide decarbonization and electrification;
- Ability to economically transfer power from other systems when needed and better prepare our system to ensure resource adequacy together with regional peers; and
- Ensure access to a diverse transmission portfolio to limit exposure to system and market disruptions that can constrain the transmission system.

PGE is required to meet mandatory FERC, North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) reliability standards and planning requirements.[269]

PGE's transmission system is also required to respond to directives issued by Reliability Coordinator (RC) West, the NERC-recognized Reliability Coordinator for PGE's portion of the Western Interconnection. PGE conducts annual transmission planning system assessments to

[269] See NERC TPL-001-4 standard, available at: https://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-4.pdf and the WECC planning criteria, available at: https://www.wecc.org/Reliability/TPL-001-WECC-CRT-3.2.pdf, for additional details.

identify minimum levels of system performance during a wide range of operating scenarios, with all system elements in service to extreme seasonal conditions and scenarios where portions of the system are out of service. These assessments include load growth forecasts, operational history, seasonal performance, resource changes and transmission topology changes. Based on these analyses, PGE identifies potential system deficiencies and determines the necessary transmission system improvements to meet customer needs reliably.

NERC planning standards define the reliability of the interconnected bulk electric system in terms of adequacy and security. Adequacy is the electric system's ability to meet aggregate electrical demand for customers consistently. Security is the electric system's ability to withstand sudden disturbances or unanticipated loss of system elements. Increasing transmission capacity often requires redundant facilities to meet NERC reliability criteria.

Historically, PGE has focused on planning and development of reliable and load service-driven transmission given our unique geographic footprint within BPA's system. Until recently, this was primarily because BPA had ample Available Transfer Capability (ATC) on their transmission system that PGE has been able to leverage to transfer new remote generation resources to PGE's Willamette Valley load. With the recognition that ATC inventories on BPA's system have been fully allocated, PGE's transmission planning will need to evolve from an approach based primarily on reliability and load service to a more proactive approach that aligns with our future load service needs as we decarbonize. It is important to recognize the significant transmission planning and project development efforts already underway that are necessary for reliable load service with PGE's load service area.

Projects currently included in PGE's Local Transmission Plan (**Table 41**) span both projects that enhance regional transmission and expand interface capacity with BPA, as well as projects that are designed to meet high concentrations of new load and enhance reliability on specific parts of PGE's system:

Table 41. Projects included in PGE's local transmission plan

Summary of regional enhancement projects	
Title	**Purpose/scope**
Harborton Reliability	Reconfigure the system to reduce exposure and provide a stronger source to Northwest Portland 230 and 115 kV systems. Planned completion 2026.
Horizon-Keeler BPA #2 230kV	Accommodate load growth in Hillsboro by constructing a new bay at BPA's Keeler Substation. Expected completion 2024.
Willamette Valley Resiliency	Strengthen and increase the resiliency of PGE's system in the Central portion of PGE's territory, north of the Salem region. Expected completion 2028.
Pearl/Sherwood 230kV Reinforcement	Mitigate the overloading of the McLoughlin-Pearl BPA-Sherwood 230 kV line caused by the loss of the Pearl BPA-Sherwood 230 kV line. Expected completion 2026.
Hillsboro Reliability	Significant upgrades to prepare for load growth in the Hillsboro area. Expected completion 2027.
Horizon Keeler BPA #1 230 kV Reinforcement	Mitigate overloads seen on the Horizon-Keeler BPA #1 230 kV line due to Hillsboro-area load growth. Expected completion 2027.
Murrayhill-Sherwood #1 and 2 230 kV Reconductor	Mitigate overloads caused by the loss of other 500 and 230 kV sources during south-to-north flow conditions in the Beaverton/Hillsboro area. Expected completion 2027.
Murrayhill-St. Mary's #2	Mitigate overloads caused by the loss of other 500 and 230 kV sources during south-to-north flow conditions in the Beaverton/Hillsboro area. Expected completion 2027.

Additionally, PGE has identified projects that are included in the OATT Attachment K Local Transmission Plan and are designed to enhance local system reliability:

- Reedville Substation Rebuild
- Memorial Substation Project
- Tonquin Substation Project
- Kaster Substation Project
- Redland Substation Project
- Scholls Ferry Substation Project
- Groveland Substation Project
- Glencullen Rebuild & Cedar Hills Breaker Project
- SE Portland Conversion Project Holgate Substation Conversion
- Mt Pleasant Substation Project

9.2.3 Regional transmission planning in advance of 2040

PGE is a member of NorthernGrid, the transmission planning organization that serves the majority of the Pacific NW and Intermountain states of the western US. NorthernGrid has fourteen members, including seven FERC-jurisdictional investor-owned utilities (IOUs), six publicly owned utilities and BPA. NorthernGrid's planning process produces its transmission plan on a biennial basis following a FERC-accepted Attachment K planning process.[270]

In addition to the NorthernGrid transmission planning process, the Western Power Pool (WPP) is currently coordinating an effort to produce two additional regional transmission studies. The first study will evaluate the risk to the transmission system because of extreme weather events like a heat dome, wildfire or west-side arctic freeze event. The WPP is also conducting a 20-year transmission planning analysis that contemplates the implementation of Oregon HB 2021 and Washington's Clean Energy Transformation Act (CETA). The purpose of the studies is to start understanding as soon as possible the extent to which these new policies will require building out the region's transmission system. Because new significant transmission projects can take 15-20 years to develop, PGE and other transmission providers in the west recognized that studying these scenarios now is necessary if the region is to meet the collective future resource targets. These studies are both expected to be complete in mid-2023.

Further, PGE will deploy a portfolio of strategies to meet the future transmission needs covered in this chapter. PGE intends to explore expanding transmission access through the acquisition of rights on third-party systems, equity investment in regional projects as they are constructed, and PGE-developed projects, including upgrades of existing assets. These different avenues of transmission expansion will allow PGE to optimize for the least cost and least risk as we plan to meet future needs.

[270] Available at: https://www.oasis.oati.com/woa/docs/PGE/PGEdocs/PGE_OATT_01012022-v2.pdf

9.3 PGE transmission rights and regional environment

9.3.1 The Pacific Northwest transmission system

Resource portfolios have grown and shifted in response to increasing loads, new large and highly concentrated loads and the significant growth of variable energy resources. However, the delivery capabilities of the Pacific Northwest's transmission system, generally, have not kept pace with these changing demands. As a result, the region is already constrained, with little or no ATC available across all time horizons.[271] This situation concerns PGE, as many future resource alternatives being explored will be located remote to PGE's retail service area and require delivery via the region's transmission system to reach PGE's service area.

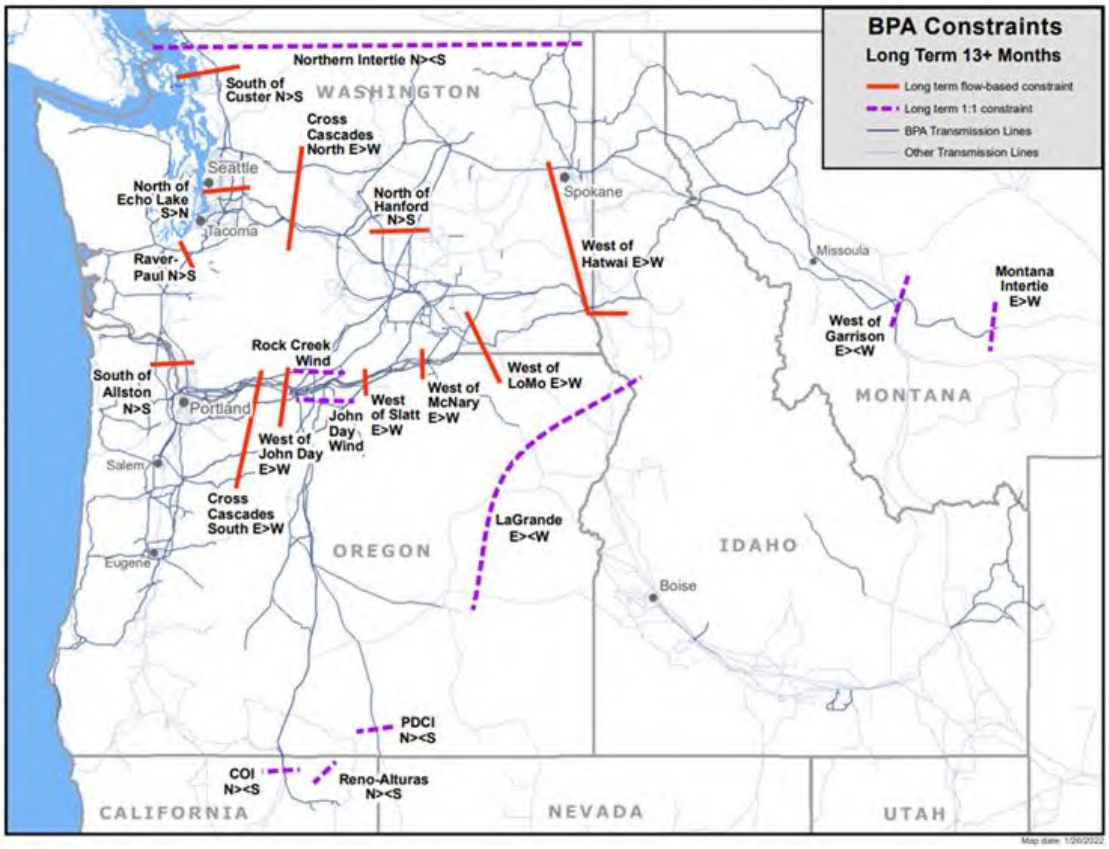
PGE's system is largely surrounded by BPA's transmission system. PGE has long relied on BPA transmission to deliver energy throughout the west to serve the PGE load. PGE currently holds over 4,000 MW of long-term firm transmission under contract with BPA. As discussed by BPA and stakeholders throughout BPA's Transmission Study and Expansion Process 2022 (TSEP),[272] BPA's system is fully subscribed, and incremental transmission requests are unlikely to be granted until the late 2020s or early 2030s, pending significant upgrades. As such, PGE is viewing future transmission planning and procurement activity recommended throughout this chapter as a way to expand and diversify transmission options as we work to decarbonize our energy associated with serving load and we need to explore doing so in a way that does not rely on BPA transmission to the same extent PGE has historically relied on BPA. It is important to recognize that the identification and development of transmission solutions are long lead activities that often take longer than the Action Plan window time horizon of this IRP. Given this dynamic, it is necessary to engage in transmission planning and development on a forward-looking basis beyond the Action Plan window.

To get to PGE's system, power generated or purchased from remote locations must travel through different paths and flowgates on the region's transmission system. A flowgate is a collection of transmission lines and facilities that collectively start in a geographically similar area and terminate in a different geographically similar area. These flowgates are typically operated by BPA and are shown in **Figure 65.** The flowgates that currently have the most significant impact on PGEM's transmission rights portfolio are the South of Allston, Raver Paul, West of John Day and Cross Cascades South, all of which are constrained, with little or

[271] See BPA Presentation, TSEP Study Process Update, September 2022 p. 6: https://www.bpa.gov/-/media/Aep/transmission/atc-methodology/09-20-22-cluster-study-improvements-customer-update.pdf
[272] Available at: https://www.bpa.gov/energy-and-services/transmission/acquiring-transmission/tsep#:~:text=The%20TSR%20Study%20and%20Expansion,Network%20Open%20Season%20(NOS).

no ATC. Additionally, BPA has identified the need for two new flowgates that will directly impact PGE's ability to access new resources over the region's transmission system. One flowgate would be in the central Oregon area and the other would bisect PGE's service area in the Portland metropolitan area. PGE will continue to engage collaboratively with BPA as the paths are developed.

Figure 65. Northwest transmission lines and flowgates on BPA system



The following summarizes the most significant flowgates and paths affecting energy delivery from remote resources to PGE's service area.

- Some amount of energy from the majority of PGE's generating resources flow across the constrained South of Allston flowgate. This flowgate is most constrained during heavy summer and heavy winter loading periods.
- A portion of the energy flowing from PGE's remote resources flows across the West of Cross Cascades South (WOCS) flowgate and, as it travels to loads in the PGE area, it flows over the West of John Day and Raver-Paul flowgates. The WOCS flowgate is most constrained during heavy winter loading, while the West of John Day and Raver-Paul flowgates are typically most constrained during heavy spring and summer loading. PGE's

Bethel-Round Butte 230 kV transmission line is part of the WOCS path, although it is currently considered to have a de minimis impact on path flows.

- Energy from PGE's resources in Montana first flow over the West of Garrison flowgate before reaching several other flowgates on the way to PGE's load in the Willamette Valley.

9.3.2 Regional transmission resources are largely constrained

Some paths, like West of Garrison, are designed to operate close to their limits, while others are not; the latter group presents areas on the system where PGE sees particular importance in continuing to study, develop and possibly construct new transmission.

Figure 66 lists the Total Transmission Capability (TTC) and ATC on BPA flowgates that affect the delivery of off-system resources to PGE. This table highlights a constrained regional transmission system, especially on transmission paths impacting energy delivery outside the PGE service area.

Figure 66. Long-term firm available transfer capacity, less pending queued requests on the BPA system (as of January 27, 2023)

		LONG-TERM FIRM AVAILABLE TRANSFER CAPABILITY (ATC) LESS PENDING QUEUED REQUESTS								
Path Name	TTC	2024	2025	2026	2027	2028	2029	2030	2031	2032
South of Allston N>S	2115	(477)	(502)	(903)	(1038)	(1274)	(1422)	(1519)	(1696)	(1798)
Cross Cascades North E>W	10250	(4021)	(2807)	(3628)	(4307)	(4552)	(5182)	(5247)	(5388)	(5924)
West of Lomo E>W	4200	(13)	(108)	(153)	(416)	(412)	(408)	(404)	(527)	(523)
Cross Cascades South E>W	7500	(1502)	(2691)	(3609)	(415)	(4883)	(5858)	(5924)	(6120)	(6445)
North of Hanford N>S	4450	211	113	(356)	(450)	(588)	(668)	(616)	(577)	(539)
Raver-Paul N>S	1450	(140)	(270)	(568)	(707)	(777)	(875)	(983)	(1043)	(1122)
West of McNary E>W	5230	235	(335)	(1527)	(1698)	(1681)	(1657)	(1660)	(1607)	(1584)
West of Slatt E>W	4670	392	258	(395)	(526)	(573)	(609)	(663)	(657)	(695)
West of John Day E>W	4530	(495)	(1134)	(1679)	(2304)	(2756)	(3433)	(3545)	(3831)	(4133)
South of Custer N>S	900	(1169)	(1026)	(1056)	(1054)	(1052)	(1050)	(1048)	(1048)	(1046)
West of Hatwai E>W	3650	(444)	(412)	(939)	(910)	(880)	(850)	(820)	(1033)	(1004)
North of Echo Lake S>N	2800	(1129)	(213)	(385)	(659)	(659)	(659)	(659)	(659)	(659)
PATH NAME	TTC MW	2024	2025	2026	2027	2028	2029	2030	2031	2032
AC Intertie N>S	2725	(447)	(497)	(597)	(597)	(597)	(1197)	(1197)	(1197)	(1197)
AC Intertie S>N	795	795	795	495	14	(286)	(586)	(1736)	(1736)	(2486)
Northern Intertie N>S	2150	(200)	(200)	(200)	(200)	(200)	(200)	(200)	(200)	(200)
Northern Intertie S>N	1120	(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)
DC Intertie N>S	3100	(609)	(458)	(458)	(458)	(458)	(458)	(458)	(458)	(458)
DC Intertie S>N	1904	1704	1704	1704	1704	1704	1704	1704	1704	1704
LaGrande E>W	413	126	73	73	73	73	73	73	73	73
LaGrande W>E	350	(180)	(180)	(180)	(180)	(180)	(180)	(180)	(180)	(180)
Montana Intertie E>W	1930	112	112	144	144	144	144	144	144	144
RATS N>S	300	(231)	(231)	(231)	(231)	(231)	(231)	(231)	(231)	(231)
RATS S>N	300	281	281	281	0	0	0	0	0	0
John Day Wind Gen	1255	149	149	99	99	99	99	99	99	99
Rock Creek Wind Gen	1200	176	176	174	174	177	177	177	177	264
West of Garrison E>W	1618	(985)	(1390)	(1490)	(1490)	(1490)	(1490)	(1490)	(1490)	(1490)
West of Garrison W>E	931	14	13	11	10	10	10	10	10	10

9.3.3 Regional transmission service request process

9.3.3.1 BPA TSR study and expansion process (TSEP)

BPA performs annual TSEP studies that combine various long-term Transmission Service Requests (TSRs) from transmission customers into a single study. The TSEP process is designed to obtain financial commitments from transmission customers before new facility construction. The cluster study process analyzes the impacts of the TSRs and new transmission facility requirements on an aggregated basis.

A TSR submitted to BPA could result in TSEP cluster study results with costly upgrades and completion dates of 10 years or longer. For example, the cost of the Montana-to-Washington upgrade project identified in the 2020 TSEP study was estimated at $1.4 billion and the earliest completion date was estimated to be 2030. It will enable an incremental 500 MW transmission service from East to West across the West of the Garrison path. PGE will likely see more high-cost and long lead-time proposals in the constrained areas of BPA's system, especially the South-of-Allston and Cross Cascades transmission areas.

9.3.3.2 2019 BPA TSEP study

In June 2019, BPA published the results of the 2019 TSEP Cluster Study. The Cluster Study comprised 105 TSRs with an associated demand of 3,993 MW. Seven BPA transmission customers submitted 59 TSRs that listed PGE as a Point of Delivery (POD) with a total transmission demand of 1,356 MW. Of the 59 TSRs submitted, 40 remain in active status. The results of those 40 active TSRs are listed in **Table 42**, including the TSR status and the required upgrade project(s). These results indicate the cost and timing of future upgrades for the incremental transmission across BPA to PGE's service area.

9.3.3.3 2020 BPA TSEP study

In May 2020, BPA published the 2020 TSEP Cluster Study results. The cluster study comprised 62 TSRs with an associated demand of 3,871 MW. Five BPA transmission customers submitted 24 TSRs that listed PGE as a POD with a total transmission demand of 1,713 MW. Of the 24 TSRs submitted, seven remain in active status. The results of those seven active TSRs are listed in **Table 42**, including the TSR status and the required upgrade project(s). These results indicate the cost and timing of future upgrades for the incremental transmission across BPA to PGE's service area.

9.3.3.4 2021 BPA TSEP study

In June 2021, BPA published the 2021 TSEP Cluster Study results. The cluster study comprised 116 TSRs with an associated demand of 5,832 MW. Eleven BPA transmission customers submitted 37 TSRs that listed PGE as a POD with a total demand of 1,851 MW. Of the 37 TSRs submitted, 26 remain in active status. The results of those 26 active TSRs are listed in **Table 42**, including the status and the required upgrade project(s). These results indicate the cost and timing of future upgrades for the incremental transmission across BPA to PGE's service area.

9.3.3.5 2022 BPA TSEP study

In June 2022, BPA published the 2022 TSEP Cluster Study results. The cluster study comprised 144 TSRs with an associated demand of 11,118 MW. 49 TSRs submitted listed PGE as a POD, with 4,515 MW requested. Of the 49 TSRs submitted, 32 remain in active status. **Table 42** lists the results of those 44 active TSRs, including the status and the required upgrade project(s). These results indicate the cost and timing of future upgrades for the incremental transmission across BPA to PGE's service area.

TSRs submitted to BPA, in the 2022 TSEP, for delivery to PGE's system resulted in cluster study results that identified costly upgrades and completion dates of 10 years or longer. **Table 42** summarizes BPA upgrades required to enable delivery of power to PGE's system from the five resource zones based on geographic relationship to generic resources modeled in this IRP.

Table 42. BPA identified upgrades by resource/generation zone

Resource zones	BPA path	Upgrade(s) required BPA TSEP	(Cost $M)	Estimated energization date
Christmas Valley Solar	1. South of Allston & Raver-Paul 2. South of Allston 3. Cross Cascades North 4. Cross Cascades South 5. Subgrid Portland-Pearl-Keeler	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Cross Cascades North Reinforcement Project	1. n/a 2. $109.2 3. $196.1 4. $233 5. $9.1 6. $382.21 7. Impact to Third-Party Transmission System (Intertie: PGE, PacifiCorp)	1. 2024 2. 2030 3. 2030 4. 2030 5. TBD 6. 2033 7. Impact to Third-Party Transmission System (Intertie: PGE, PacifiCorp) 8. n/a

Resource zones	BPA path	Upgrade(s) required BPA TSEP	(Cost $M)	Estimated energization date
	6. Subgrid Central Oregon South 7. Impact to Third-Party Transmission System (Intertie: PGE, PacifiCorp) 8. Subgrid-Impact to Third-Party Transmission System (PacifiCorp: South Oregon 230 kV network between Chiloquin, Klamath Falls and Alvey) 9. Subgrid -Impact to Third-Party Transmission System (PGE: North of Sherwood)	4. Big Eddy-Chemawa 500 kV Rebuild Project 5. Pearl-Sherwood-Mcloughlin Reinforcement Project 6. Central Oregon South 500 kV Project 7. Impact to Third-Party Transmission System (Intertie: PGE, PacifiCorp) 8. Impact to Third-Party Transmission System (PacifiCorp: South Oregon 230 kV network between Chiloquin, Klamath Falls and Alvey) 9. Impact to Third-Party Transmission System (PGE: North of Sherwood)	8. n/a 9. TBD	9. TBD
Gorge Wind	1. South of Allston & Raver-Paul 2. South of Allston 3. Cross Cascades North 4. Cross Cascades South 5. Subgrid Portland-Pearl-Keeler	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Cross Cascades North Reinforcement Project	1. n/a 2. $109.2 3. $196.1 4. $233 5. $9.1 6. $35.39 7. TBD	1. 2024 2. 2030 3. 2030 4. 2030 5. TBD 6. 2028 7. TBD

Resource zones	BPA path	Upgrade(s) required BPA TSEP	(Cost $M)	Estimated energization date
	6. Raver-Paul 7. Subgrid -Impact to Third-Party Transmission System (PGE: North of Sherwood)	4. Big Eddy-Chemawa 500 kV Rebuild Project 5. Pearl-Sherwood-Mcloughlin Reinforcement Project 6. BPA Chehalis to Cowlitz tap 230 kV Rebuild Project 7. Impact to Third-Party Transmission System (Portland General Electric: North of Sherwood		
SE WA Wind	1. South of Allston & Raver-Paul 2. South of Allston 3. Cross Cascades North 4. Cross Cascades South 5. Subgrid Portland-Pearl-Keeler 6. Raver-Paul 7. Subgrid -Impact to Third-Party Transmission System (PGE: North of Sherwood)	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Cross Cascades North Reinforcement Project 4. Big Eddy-Chemawa 500 kV Rebuild Project 5. Pearl-Sherwood-Mcloughlin Reinforcement Project 6. BPA Chehalis to Cowlitz tap 230 kV Rebuild Project 7. Impact to Third-Party Transmission	1. n/a 2. $109.2 3. $196.1 4. $233 5. $9.1 6. $35.39 7. TBD	1. 2024 2. 2030 3. 2030 4. 2030 5. TBD 6. 2028 7. TBD

Resource zones	BPA path	Upgrade(s) required BPA TSEP	(Cost $M)	Estimated energization date
		System (Portland General Electric: North of Sherwood)		
Off-Shore Wind	1. South of Allston & Raver-Paul 2. South of Allston 3. Cross Cascades North 4. Cross Cascades South 5. Subgrid South Oregon Coast 6. Subgrid -Impact to Third-Party Transmission System (PGE: Santiam-Bethel & North of Sherwood)	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Big Eddy-Chemawa 500 kV Rebuild Project 4. Pearl-Sherwood-Mcloughlin Reinforcement Project 5. Southern Oregon Coast Reinforcement Project 6. Impact to Third-Party Transmission System (Portland General Electric: Santiam-Bethel & North of Sherwood)	1. n/a 2. $109.2 3. $196.1 4. $233 5. 903.66 6. TBD	1. 2024 2. 2030 3. 2030 4. 2030 5. 2033 6. TBD
Montana Renewables	1.West of Garrison E>W	1. M2W	1.$350M	1. 2030
Projects, cost and energization dates from BPA's 2022 TSEP				

Capacity limits from the generic resource zones were developed based upon PGE's experience with ATC, transmission that may be acquired by developers and the results of the 2022 TSEP.

9.3.3.6 Montana transmission

Wind resources in Montana are attractive because of their higher capacity factors and diverse seasonal output compared to the Washington and Gorge wind currently in PGE's resource portfolio. HB 2021 decarbonization requirements and coal restrictions provide an opportunity to evaluate Montana resources and the potential repurposing of PGE's existing Colstrip transmission rights to serve future PGE load from a renewable resource over the same transmission currently used to deliver Colstrip output to PGE's system.

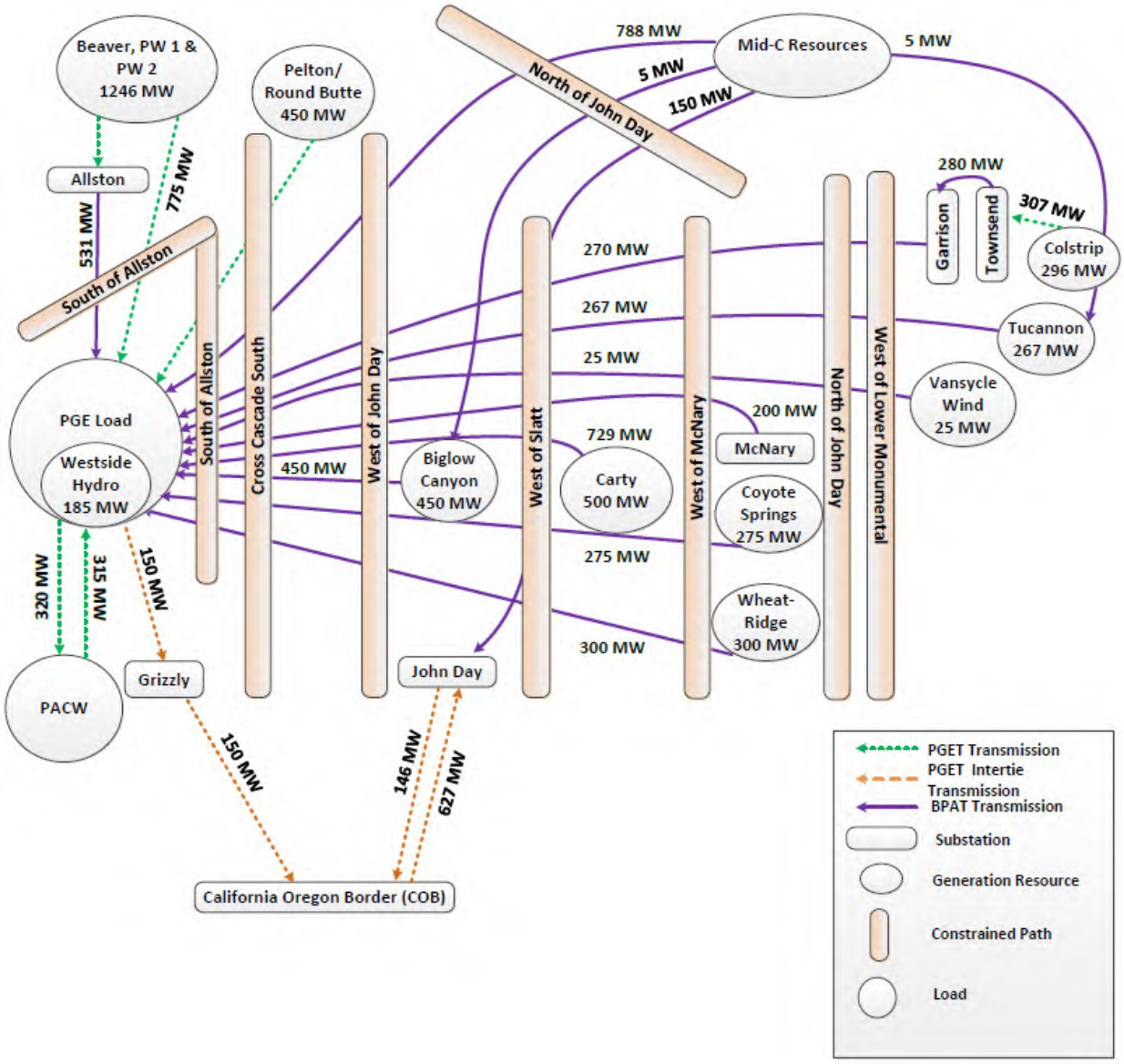
9.3.4 PGE merchant transmission portfolio

PGEM is responsible for obtaining the transmission service needed to serve PGE retail customer load and for scheduling the use of that transmission most efficiently and economically to meet demand. The transmission portfolio facilitates PGE's ability to:(1) deliver energy from generating resources to load during all seasons, (2) participate in regional energy markets and (3) optimize PGEM's energy portfolio.

PGEM's transmission portfolio consists primarily of capacity rights on the PGET and BPA systems, including the NWACI, the Colstrip Transmission System and Montana Intertie, enabling energy pathways through and into the Pacific Northwest. Due to the geographic location of PGE's service area compared to where most generation resources are or will be located, most of PGE's generation resources are outside of PGE's service area. Historically, PGEM has relied on BPA transmission rights to import power from remote generation resources and to deliver power purchases to serve PGE's load. PGEM also holds transmission rights to access the Pacific Northwest Mid-Columbia (Mid-C) wholesale power hub, which PGE relies on for balancing load, meeting peak demand and enabling economic transactions. See **Figure 67** for an overview of PGEM's transmission portfolio.

Figure 67 provides a snapshot of PGEM-contracted transmission scheduling rights to support the delivery of PGE-owned generation, power purchase agreements (PPAs) and market purchases. The tan bars in **Figure 67** represent BPA-managed flowgates. Due to the electron flow-based nature of the interconnected grid, constraints on these flowgates create limits on transfer capability to PGE's load centers, irrespective of where the source generation is located, whether on BPA's system or further away. Additionally, as described in this chapter, BPA is looking to establish new flowgates that will impact flows to and through PGE's service area.

Figure 67. Snapshot of PGE's market function transmission portfolio with generation resources and transmission



PGEM may also use its contracted transmission rights to access the Western EIM through transmission with Avista Corp, BPA, CAISO, Northwestern Montana, PacifiCorp, Puget Sound Energy, Seattle City Light and Tacoma Power. Access to the EIM enhances PGE's ability to efficiently integrate variable resources on an intra-hour energy basis and deliver the least-cost energy supply to customers. As additional wholesale market options develop in the West, like the CAISO's Extended Day Ahead Market or the Southwest Power Pool's Markets +, PGE may use its transmission portfolio to engage in these future opportunities.

9.4 Options to address transmission need

As discussed earlier in this chapter, there is a limited amount of long-term firm and conditional firm TSRs in study or confirmed status across BPA's system, deliverable to PGE without costly system upgrades. The total amount of each transmission product available is in the following table, roughly 1,800 MW combined (**Table 43**). At the same time, PGE expects to add approximately 3,000 to 4,000 MW of non-emitting resources to meet HB 2021 goals. In many scenarios, the resources needed to meet the adequacy and non-emitting energy goals require more transmission than is available.

Table 43. Transmission service requests on BPA pointed to PGE[273]

Conditional firm	Long-term firm
1,128 MW	690 MW

This need for additional generating resources to serve load in compliance with state law in contrast with a lack of available long-term transmission options creates a near-term need within PGE's resource plan and points to a long-term need that is outside of the IRP action window that, given the long development cycles necessary for transmission, warrant early engagement.

9.4.1 Proxy transmission options identify transmission need

To maintain system adequacy and achieve GHG reductions, PGE has analyzed transmission proxy options as part of the 2023 IRP. Like resource proxies, transmission proxies describe general characteristics that may be found on the market. If a portfolio selects a transmission proxy, that indicates that the model sees a need to expand PGE's transmission network for GHG reduction or resource adequacy purposes. PGE's portfolio modeling indicated that transmission need existed (and proxies were optimal) to meet BPA system need through the SoA proxy and to expand access to regional resources.

For the 2023 IRP, the capacity expansion model ROSE-E has two types of transmission proxies from which to choose. The choices in **Table 44** are 1) a Northwest transmission upgrade and 2) purchasing the rights on a transmission line to Wyoming or the Desert Southwest.

[273] Values represent all PGE resource zones and are based on the BPA TSEP.

Table 44. Proxy transmission options[274]

Proxy transmission option	Accompanying resource	Details
South of Allston upgrade (available as early as 2027 in most portfolios, $1.97/kilowatt (kW)-month)	IRP proxy resources	Increased transfer capacity on PGE's share of South of Allston via upgrade. Allows up to 400 MW of additional capacity for regional proxy resources.
Generic proxy transmission (Tx) (Available as early as 2026 in select portfolios$20.46/kW-month to WY, $23.04/kW-month to SW)	Wyoming wind	Model can select a Tx path to access Wyoming wind.
	Desert SW Solar	Model can select a Tx path to access Desert Southwest solar.

The South of Allston upgrade alleviates congestion on the BPA system and unlocks up to 400 MW of Northwest proxy resources, like Gorge Wind or Christmas Valley solar. It is available for selection as early as 2027 in most portfolios, indicating that this need could be alleviated by the acquisition of additional rights and, eventually, the exploration of new builds or upgrades.

Transmission to Wyoming or the Desert Southwest adds an equivalent amount of transmission capacity and a wind farm in Wyoming or a solar facility in southern Nevada (for example, 200 MW of Wyoming transmission includes 200 MW of Wyoming wind). The Nevada and Wyoming transmission proxies are available for portfolio selection as early as 2026 in select portfolios, again indicating that this identified need could be met through transmission rights, partnership in projects currently being developed, and/or additional development on a longer-term time horizon. These transmission projects have the same characteristics as the other IRP proxy resources, though their differing location changes their generation profiles. Additional information about these projects, including monthly capacity factors and other details, is in **Chapter 8, Resource options**.

Beyond providing access to renewables, the IRP assumes that transmission to Wyoming or the Desert Southwest also provides market capacity at a 1-to-1 ratio (every MW of

[274] Saadi, Fadl H, et al. "Relative Costs of Transporting Electrical Chemical Energy." *Energy & Environmental Science*, *Energy & Environmental Science*, no. 3, 29 Jan. 2018, pp. 469–475.

transmission acquired provides 1 MW of effective capacity). This is a simplifying assumption for modeling purposes only and capacity additions will be driven by access to additional climate zones through specific transmission projects and the resources within the climate zones. Additional planning for capacity will be informed by the concurrent development of the Western Resource Adequacy Program ("WRAP"), a regional day-ahead market (EDAM with CAISO or Market Plus with SPP), as well as the development of new program and storage technologies. The actual operational capacity needs will be revisited as regional conversations and study processes progress.

9.4.1.1 Transmission as a gateway to diversification

Transmission expansion in the IRP falls into two categories, Northwest expansion and expansion to other regions. The Northwest expansion increases access to resources located in the Northwest. Portfolio selection of regional proxy transmission allows access to additional climate zones and markets that could offer diversified resource options across the planning horizon.[275]

The concept of regional load diversity as a benefit is embedded in the design of the WRAP. The WRAP is planning to standardize peak capacity planning for utilities operating in the WECC region that are not within an RTO. This program will facilitate the daily exchange of resources and obligations from resources in regions that are in excess capacity to regions that find themselves in deficit. As a key component of this program's many benefits, participating utilities would be able to reduce their individual Planning Reserve Margin ("PRM") based on the regional load diversity. Each utility would have had to procure or build to a much higher capacity target had it not been for the transparency and standardization that the WRAP offers.

Underlying the WRAP is the ability of each of these diversified regions to transmit energy back and forth. More benefits would be associated with this program if there were more transmission capacity between the regions.

Further discussion of the WRAP can be found in **Section 3.2, Regional planning: resource adequacy**, including program details, benefits and applicability in this and future IRPs.

[275] This does not preclude PGE from exploring transmission options to other regions.

9.4.2 Other transmission options

The transmission options tested in the 2023 IRP are proxy resources. Other transmission options, either to Northwest resource locations or to other regions, may also be available. Non-wire solutions may also be available to assist with transmission congestion. Including proxy transmission resources does not preclude PGE from exploring other transmission and/or non-wire options in future planning and acquisition work.

9.4.3 Bethel to Round Butte upgrade for future load service

With the recognition that transmission system capacity inventories on the BPA system are or are expected to be fully allocated, PGE must look for other commercial transmission development opportunities that could enable the affordable delivery of these new non-emitting resources to PGE's service area. It is widely accepted that most new resources will be located east of PGE's service area, on the other side of the Cascade Mountain Range. PGE owns one transmission line that crosses the Cascades, the Bethel-Round Butte 230 kV line that runs from approximately the Salem area to Round Butte near Madras, OR.

The Bethel-Round Butte 230 kV line was conceived in the 1960s as part of the Pelton-Round Butte Hydro project to deliver the output of the Pelton-Round Butte hydro facility to PGE's load in the Willamette Valley. Most of the line is constructed on wooden H-frame structures and is prone to damage from significant weather events, including wind, snow/ice and wildfires. During the wildfire season in 2020, a portion of the Bethel-Round Butte line was damaged by fire and had to be repaired, taking the line out of service for several months while those repairs were made, resulting in an extended transmission outage.

The eastern terminus of the Bethel-Round Butte 230 kV line, at Round Butte Substation, is then connected to the NWACI via the Round Butte-Grizzly 500 kV line. The Grizzly substation, jointly owned by PGE and BPA, is a significant substation on the NWACI. The NWACI is a collection of 500 kV transmission facilities that run from the John Day substation near the Columbia River to two different substations near the California-Oregon border, commonly referred to as the "COB" scheduling interface with the California Independent System Operator (CAISO). The NWACI facilities are primarily owned by PGE, PacifiCorp and BPA and jointly operated as a single path by BPA. Idaho Power will also have a scheduling point presence on the NWACI according to the term sheet announced by BPA, PacifiCorp and Idaho Power when BPA withdrew from being a funding partner for the Boardman to Hemingway project.

The Bethel-Round Butte 230 kV line is an existing facility with an existing Right of Way (ROW) across the Cascade Mountains. The acquisition and permitting of greenfield transmission line ROWs is the single most challenging part of developing new transmission infrastructure in

Oregon. For example, Idaho Power and PacifiCorp's Boardman to Hemingway project has been in various stages of the permitting process for nearly two decades. While there may need to be some additional ROW changes made to the existing Bethel-Round Butte ROW, because PGE already owns the ROW, it is expected to be significantly less complex than a new greenfield ROW acquisition would be.

Increasing the transfer capability between PGE's system and the NWACI will provide PGE with significant incremental direct access to solar and wind resource-rich parts of Oregon and connections with neighboring transmission providers and western markets.

Rebuilding the Bethel-Round Butte line from 230 kV to 500 kV would require replacing all the wooden H-frame structures currently in place with significantly taller and more robust steel lattice towers that are less susceptible to wildfire impacts.

Chapter 10. Resource economics

As Portland General Electric (PGE) makes the energy transition to a decarbonized system, there are many elements to be considered. The economics of resources represent a crucial element of these dynamics within IRP analyses. In this chapter, we describe the relevant costs associated with each resource and summarize the associated benefits. We also visualize how resource comparisons can occur outside portfolio analysis by comparing resources on a net cost basis, which becomes the basis for the avoided cost approach.

Chapter highlights

- Resource costs are primarily a function of fixed costs in the current planning environment.
- With different resources providing disparate benefits, such as providing energy benefits and storage providing capacity benefits, resource competition is evolving within those two categories.
- The inclusion of non-cost-effective Distributed Energy Resources (DER) provides insight into how their role can be further magnified in a decarbonized future.
- The relative costs and benefits of different energy and capacity resources that will form the basis for resource selections in portfolio analysis are displayed.

10.1 Fixed costs

Fixed costs for new resource options in the 2023 IRP consist of fixed capital carrying costs and fixed operating costs. Fixed cost calculations are based on resource-specific data and PGE-specific assumptions, including the cost of capital, long-term inflation and taxes. To streamline resource modeling, costs that are technically variable in nature (as in, costs vary with a resource's energy generation) are included in the fixed cost calculation (**Table 45**). These costs generally have a fixed generation pattern in PGE's dispatch modeling **Appendix H, 2023 IRP modeling details**. As a result of this dispatch modeling treatment, the annual generation of variable wind and solar resources is known and can be assumed as a fixed quantity. A summary of the types of items included in PGE's fixed cost modeling is provided in the following table.

Table 45. Fixed cost calculation data and assumptions

Fixed capital carrying costs	Fixed operating costs	Variable operating costs treated as fixed
Book and tax depreciation	Fixed operation and maintenance costs	Production tax credits (benefit)
Required return	Fixed wheeling costs	Variable energy resource (VER) integration
Property tax and federal and state income tax	Fixed fuel transportation costs	Land lease

Fixed costs for new resources are incorporated into portfolio analysis by applying the annualized fixed cost (on a kW-year basis) for each year in which the resource is included in the portfolio. Annualization of fixed costs occurs over the entire economic life of each resource. Annualized fixed costs are specified by resource vintage (commercial operation date or "COD") to capture the effects of capital cost declines and other time-varying parameters.[276] For each technology, the 2023 IRP analysis examines three different capital cost scenarios (Low, Reference, High) that capture uncertainties in future cost declines (**Figure 68, Figure 69** and **Figure 70**). Resources for which Reference Case capital cost data were derived from the Energy Information Administration Annual Energy Outlook (EIA AEO) information use the EIA reference cost trajectory. All other data are sourced from the National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB). These cost projection futures are based on the following possible paths for technological advancement:[277]

Low – NREL ATB Advanced Scenario – Innovations far from market-ready today are successful in the future and have become widespread in the marketplace. New technology architectures could look different from those observed today – public and private R&D investment increases.

Reference – NREL ATB Moderate Scenario – Innovations observed in today's marketplace become more widespread and nearly market-ready innovations come into the marketplace. Public and private research and development (R&D) investment continues at current levels. This scenario may be considered the expected level of technology innovation.

[276] Commercial operation date is defined as the date after which all testing and commissioning have been completed and is the date on which a facility starts to generate power to earn revenue.
[277] NREL. 2021 Electricity ATB, available at: https://atb.nrel.gov/electricity/2021/definitions

High – NREL ATB Conservative Scenario – Historical investments come to market with continued industrial learning. Technology is like that deployed in the marketplace today, with a few changes from technological innovation. Public and private R&D investment decreases.

Figure 68. Fixed cost scenarios for new lithium-ion battery storage resource options

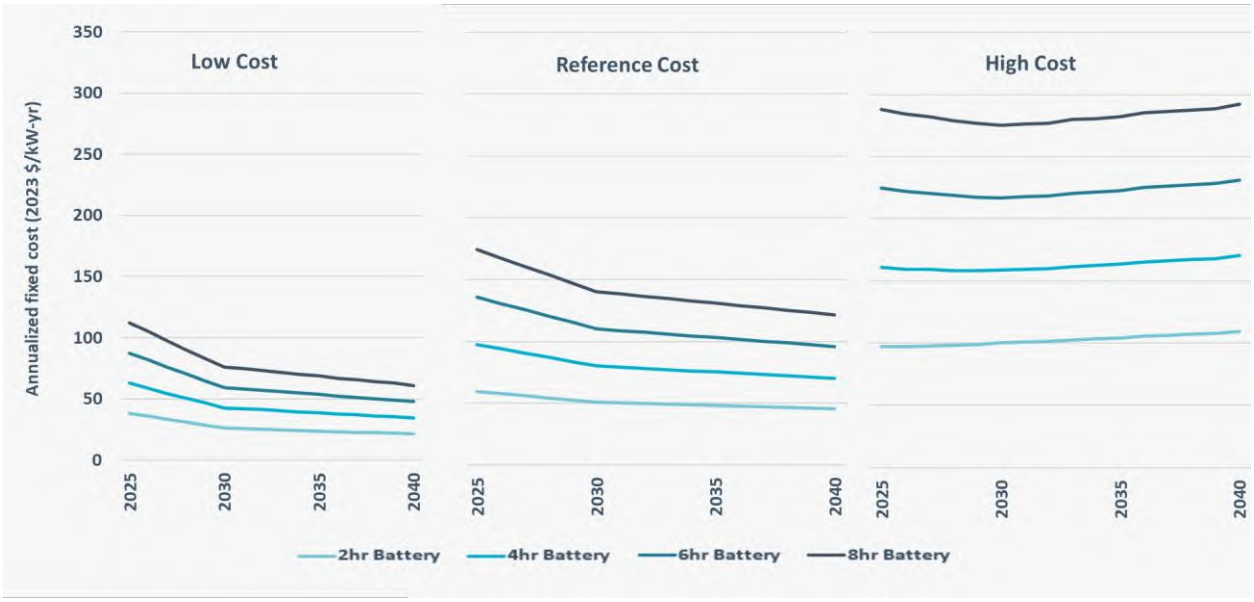


Figure 69. Fixed cost scenarios for new solar Photovoltaic (PV) resource options

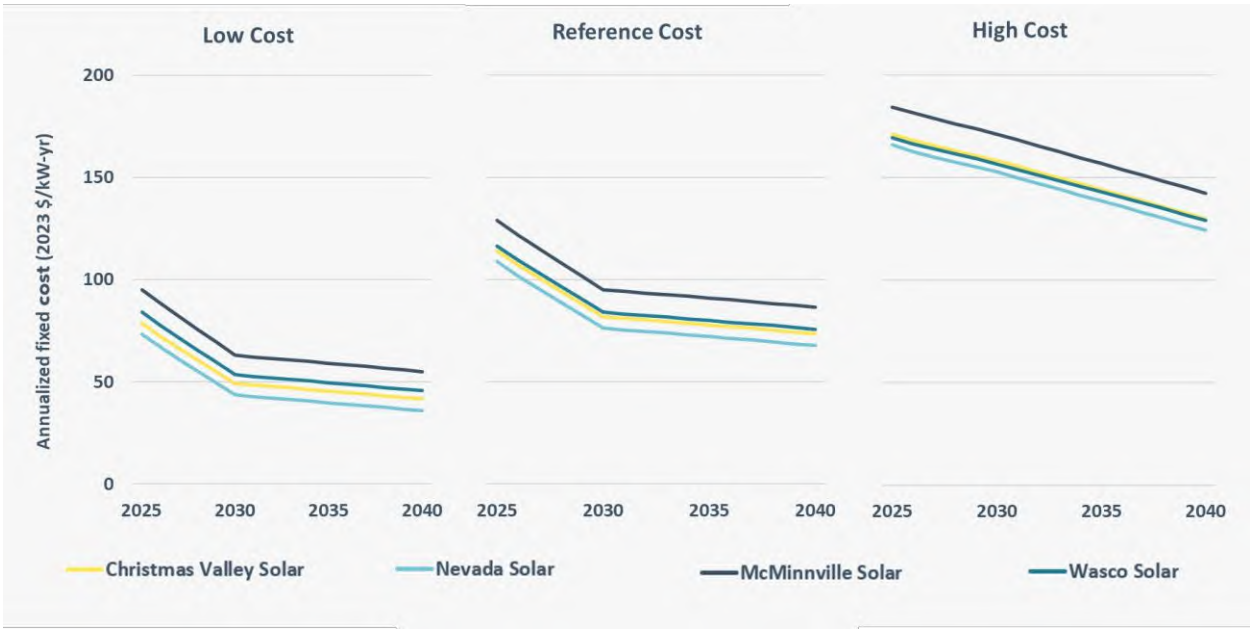
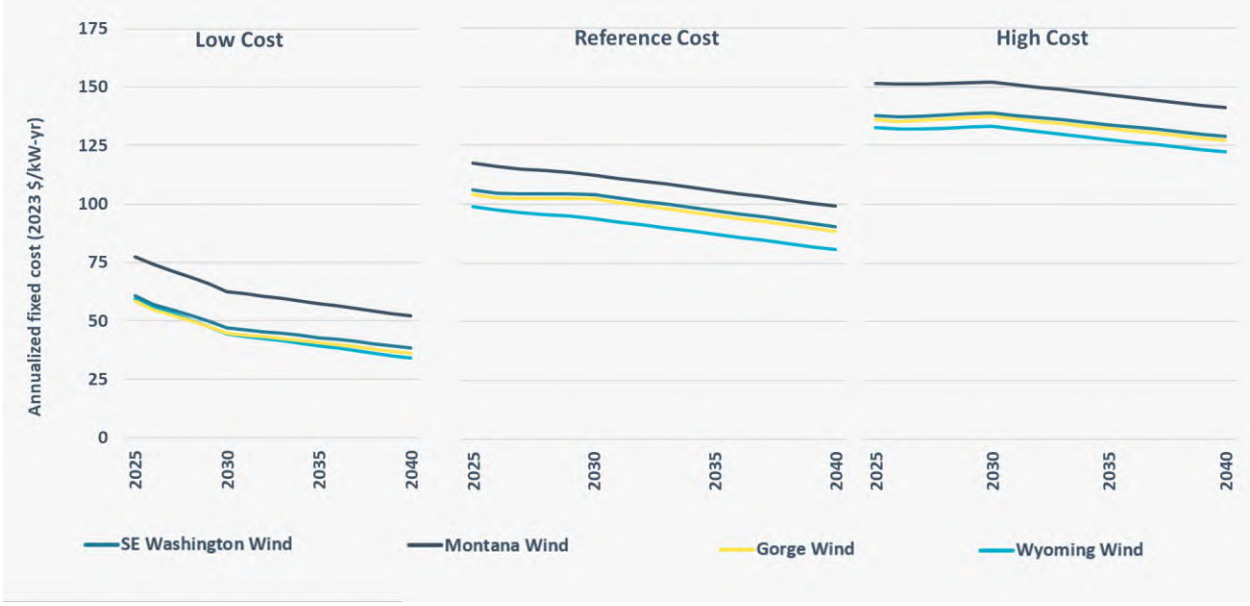


Figure 70. Technology maturity outlook for new onshore wind resource options



10.2 Variable costs

PGE assessed the total levelized variable cost of candidate new resources by performing hourly simulations from 2023 to 2043 of their dispatch across multiple price and input futures. The PZM simulation is used for this analysis as it can maximize resource value given resource availability, input prices and operational constraints. Total variable costs are composed of variable operation and maintenance costs, fuel and start-up costs and the costs associated with emissions, where applicable.[278] **Table 46** summarizes the levelized variable costs for each resource option under the Reference Case over the economic life of each resource option.

[278] All renewable resources are modeled as "must-run" with a fixed hourly shape that is varied by month as identified in **Appendix M, Supply-side options.** Daily operation might impose shutdowns for system balancing reason or because of transmission bottlenecks but such events cannot be foreseen and are therefore not embedded in resource evaluation. Although it is not possible to forecast the expected curtailment for any single resource, a simulation of regional potential curtailment of the total installed wind and solar resources for the Oregon and Washington macro area is presented in **Appendix N, Renewable curtailment**.

Table 46. Levelized variable cost (2023$/MWh) COD 2026[279]

	Levelized variable cost (2023$/MWh)	
	Reference Case	Range
Biomass	$51.44	$8.83 - $67.47
Combined-cycle combustion turbine (CCCT)	$20.50	$3.66 - $36.26
Combined-cycle combustion turbine carbon capture sequestration (CCCT_CCS)	$43.16	$5.53 - $149.5
Nuclear	$11.60	$2.61 - $12.11
(Simple-cycle combustion turbine (SCCT)	$28.39	$4.9 - $43.77
Small modular reactor (SMR)	$11.81	$2.52 - $12.91

10.3 Flexibility value and integration cost

Flexibility value and integration cost are critical components of variable and capacity resource economics. As defined in **Section 6.8, Flexibility adequacy**, flexibility adequacy needs encompass multiple operational value streams, including load following, regulation, spin, non-spin and renewable integration (ramping and forecast error mitigation). PGE defines flexibility value as the benefits provided by resources that help meet the system's flexibility adequacy target. Integration costs are the inverse of this benefit, generally attributed to VERs as their intermittent behavior increases the megawatts (MW) needed to meet flexibility adequacy targets.

PGE estimated the flexibility value and integration cost of new resources using Grid Path simulations of the PGE service area.[280] When additional resources are added to the system, some new resources can be used to serve load and avoid higher-cost market purchases, as well as enable the re-dispatch of existing resources, thereby affecting the flexibility needs of the system. At the same time, other resources may increase the flexibility needed. For new

[279] Renewable resources and battery storages do not incur fuel cost and do not emit CO2. Therefore, the associated variable costs are zero and not shown in the table. The range represents the semi-deviation of variable costs across all futures.

[280] Grid Path is an open-source modeling software developed by Blue Marble Analytics. This model is used to perform the flexibility assessment in the 2023 IRP. Additional details on Grid Path are available in **Ext. Study-IV, Flexibility study**

resource options, either a flexibility value or an integration cost is calculated by subtracting the market revenues associated with dispatching the resource from a change in the total system cost achieved by including the resource in the portfolio and dividing by the resource addition size.

PGE's estimates of flexibility values and integration costs for several new resources based on a 2026 and 2030 test year are summarized in **Table 47**. The difference in flexibility value between storage resources does not appear to be significantly impacted by duration, suggesting that most flexibility value is associated with flexibility constraints on short time scales (less than two hours).

Table 47. Flexibility value ($/kW-yr.) of new resources in 2026 and 2030

Resource	2026	2030
2-hour Battery	8.35	16.71
4-hour Battery	9.77	18.75
6-hour Battery	10.68	20.65
8-hour Battery	11.78	21.38
10-hour Pumped Storage	11.47	20.86

Table 48 displays the estimated costs of resource integration. As noted in the table, solar + storage resources increase integration costs in the short term but are expected to deliver system benefits (negative integration costs benefit the system) as the system evolves by 2030. This is not a function of any specific element but reflects the system's evolving nature between 2026 and 2030, driven by load growth, DERs and changes to supply.

Table 48. Integration costs ($/MWh) of new resources in 2026 and 2030

Resource	2026	2030
Gorge wind	2.57	3.90
WA wind	2.57	3.90
MT wind	0.95	1.46
Solar	2.84	3.30
Solar + Storage	0.33	-1.62

10.4 Energy value

PGE uses the PZM simulation to estimate the economic dispatch of existing generation resources, contracts and potential new resources using electricity prices and associated risk variable inputs from each price future. Economic dispatch leads dispatchable resources to generate when their dispatch costs are less than the market electricity price, subject to all modeled operational constraints.

Table 49 summarizes the Reference Case energy value and range of outcomes across the simulated price futures for each resource. These values are presented on a levelized basis, across each resource's economic life, for representative resources with 2026 commercial operation dates.

Table 49. Energy values for new resource options (2026 COD)[281]

	Levelized energy value (2023$/MWh)	
	Reference Case	**Range**
Solar PV Christmas Valley	$17.78	$2.83 - $30.08
Solar PV McMinnville	$16.85	$2.68 - $28.7
Solar PV Nevada	$19.51	$3.12 - $32.72
Solar PV Wasco	$16.50	$2.62 - $28.13
Wind Gorge	$21.97	$3.54 - $36.8
Wind MT	$26.39	$4.26 - $43.4
Wind SE Washington	$24.34	$3.92 - $40.28
Wind Wyoming	$27.18	$4.39 - $44.64
Wind Offshore	$23.55	$3.79 - $39.29
1:1 Hybrid Christmas Valley	$20.85	$3.12 - $35.05
2:1 Hybrid Christmas Valley	$18.63	$3.00 - $31.56
1:1 Hybrid McMinnville	$21.15	$3.18 - $35.69
2:1 Hybrid McMinnville	$18.29	$2.95 - $31.06
Geothermal	$24.46	$3.94 - $40.65
Biomass	$26.04	$4.09 - $64.44

[281] Ranges reflect upward and downward semi-deviations around the Reference Case across the market price futures.

	Levelized energy value (2023$/MWh)	
	Reference Case	**Range**
CCCT	$35.48	$6.61 - $54.19
CCCT w/ CCS	$49.81	$6.30 - $195.79
SCCT	$39.49	$6.63 - $59.41

10.5 Resource capacity contribution

In **Chapter 6, Resource needs**, the IRP describes future system capacity needs. These needs grow from a combination of expected load growth and resource loss. To fill these needs, the IRP adds new resources. To determine how much effective capacity new resources add to the system, PGE conducts an effective load-carrying capability (ELCC) study for each new resource.

ELCC describes what percentage of a resource's nameplate capacity can be depended upon for resource adequacy needs. For example, the 100 MW nameplate capacity of a 4-hour battery may have an ELCC of 44 percent in the winter. This means that the 100 MW nameplate capacity of a 4-hour battery contributes 44 MW (100 * 0.44) towards reducing system capacity needs. If the starting system has a winter capacity need of 200 MW, after adding a 100 MW 4hr battery, the new capacity need is 156 MW (200 MW of need 44 MW of capacity).

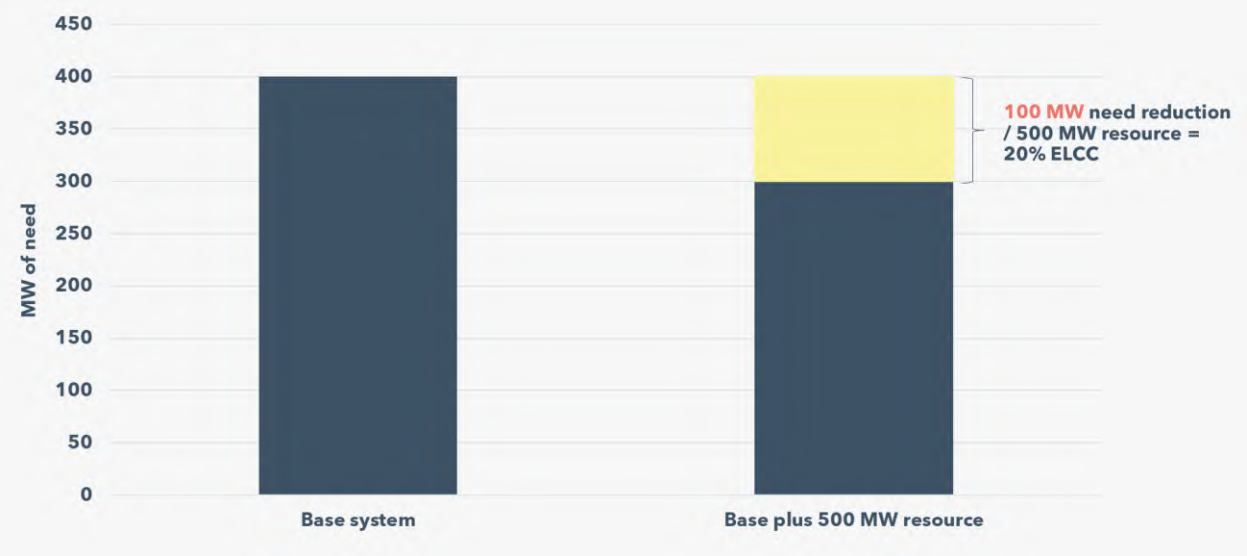
PGE uses the Sequoia model to calculate ELCC values, following these steps:

- The model runs once to establish a baseline system capacity need
- The model runs again with a new resource added
- The difference in capacity need from the base system to the system with the resource added determines how much effective capacity the resource contributes
- The amount of effective capacity the resource contributes is divided into its nameplate to determine the ELCC value

For example, if the base system has a capacity need of 400 MW, and the same system plus a 500 MW nameplate resource has a capacity need of 300 MW. In that case, the resource provides 100 MW of effective capacity (400 minus 300). The effective capacity

contribution,100 MW, is divided into the resource nameplate, 500 MW, to arrive at the ELCC value of 20 percent.[282] This example is graphically shown in **Figure 71.**

Figure 71. ELCC calculation example



The 2023 IRP tests resource ELCCs in the year 2026. The base 2026 power system has a resource deficit in both seasons. ELCCs can be calculated untuned, with a system deficit or tuned, where the base power system has had resources added until it is adequate or nearly adequate. For portfolio creation, PGE runs ELCC studies in an untuned system. PGE also runs a tuned ELCC study that includes the IRP Preferred Portfolio. Full ELCC values for portfolio creation are in **Appendix J, ELCC sensitivities**. Tuned ELCC values are in **Appendix K, Tuned system ELCCs**.

The 2023 IRP uses seasonal ELCC values rather than annual values. With many resources, ELCC values differ by season. For example, storage resources tend to have higher ELCCs in the summer than in winter. A seasonal approach helps ensure that the portfolio model (ROSE-E) can select an optimal and seasonally balanced portfolio.

Table 50 has untuned system ELCCs values for the first 100 MW of the IRP supply-side resources considered inside the Action Plan window. The resources use either firm or conditional firm 200hr transmission (CF200). For IRP modeling, CF200 transmission curtails the resource during the 100 highest load hours of the year, lowering ELCC values.[283] In IRP modeling, resources typically use CF200 transmission after firm transmission is exhausted.

[282] This approach is similar to how the Northwest Power and Conservation Council determined resource capacity contributions in the 7th Power Plan (the Council calls this approach associated system capacity contribution).
[283] See **Appendix J, ELCC sensitivities** for more detail on how transmission products influence ELCC estimates.

Table 50. ELCC values for portfolio creation in year 2026[284]

Resource (100 MW nameplate)	Summer		Winter	
	Firm Tx	CF200	Firm Tx	CF200
Gorge Wind	47%	29%	39%	26%
SE WA Wind	15%	10%	35%	29%
MT Wind	28%	14%	61%	46%
McMinnville Solar	27%	9%	6%	6%
Wasco Solar	14%	6%	5%	4%
Christmas Valley Solar	23%	7%	8%	8%
McMinnville Solar Hybrid (1:1)	106%	55%	53%	43%
McMinnville Solar Hybrid (2:1)	72%	35%	30%	24%
Christmas Valley Hybrid (1:1)	102%	56%	55%	47%
Christmas Valley Hybrid (2:1)	63%	33%	33%	30%
2-hr battery	49%		27%	
4-hr battery	69%		44%	

ELCC values tend to decline due to resource saturation. For instance, the ELCC value of 100 MW of solar is higher than the ELCC value of 1,000 MW of solar. This occurs for various reasons, including:

- As more resource is added, the number of outages available to solve decreases. For example, if 500 MW of solar is added to a system, some outages during daylight hours may be solved. As a result, the next increment of solar added will have fewer outages available to solve and have a lower ELCC value.
- For storage resources, higher levels of resources may not be able to fully charge due to a lack of system energy. For example, there may be sufficient energy to charge 100 MW of a 4-hr battery reliably but not enough energy to charge 1,000 MW of a 4-hour battery. As a result, the 100 MW battery may have a higher ELCC value than the 1,000 MW battery.

[284] 2- and 4-hour batteries are modeled to be on-system. Accordingly, there are no transmission limitations included in ELCC calculations, equivalent to having firm transmission.

ELCC values reflect the percentage of the resource nameplate MW that can be relied upon for effective capacity. They do not reflect the total MW of effective capacity provided by the resource, which is equal to the ELCC value multiplied by the nameplate. Although 100 MW of a 4-hour battery in the winter has an ELCC of 44 percent, and 500 MW of a winter 4-hour battery has an ELCC of 32 percent, the 500 MW battery provides more effective MW of capacity (160 MW vs. 44 MW, in this example). More discussion on ELCCs is in **Appendix J, ELCC sensitivities**.

10.6 Capacity value

Portfolio analysis addresses system capacity needs through resource additions such that the resource contributions meet or exceed the model's seasonal capacity need constraints. More details on the modeling process are available in **Appendix H, 2023 IRP modeling details**.

Like in the 2019 IRP, the value of capacity outside of portfolio analysis is calculated by developing the net cost of capacity. The net cost of capacity is the cost required to get 1 kilowatt (kW) of capacity contribution from the next least cost capacity resource available to meet capacity needs, as shown in the following formula:[285]

$$Net\ cost\ of\ capacity\ for\ 1kW\ of\ capacity\ contribution\ =$$

$$(fixed\ costs + transmission\ costs\ + integration\ costs - tax\ credits - energy\ value - flexibility\ value)/_{ELCC}$$

Figure 68 (**Section 10.1, Fixed costs**) highlights the considerable uncertainty in the relative fixed cost trajectories of capacity resources such as batteries. **Table 47** in **Section 10.3, Flexibility value and integration cost**, quantifies the integration flexibility value of new capacity resources. ELCC of the first 100 MW of each resource is described in **Section 10.5, Resource capacity contribution**.

PGE has analyzed the Preferred Portfolio to determine the next least cost capacity resource available to meet capacity needs in 2026. The Preferred Portfolio is described in **Section 11.5, Preferred Portfolio**. From a capacity standpoint, the Preferred Portfolio adds 232 MW of 4-hr storage resource in 2026 to address the bulk of the capacity needs resulting from expiring contracts and load growth. Beyond this, through 2030, additional capacity is added through energy-dense resources such as wind, solar, community-based renewable energy (CBRE) and proxy transmission access to Nevada to add energy and capacity. Evaluating all

[285] This equation is also commonly referred to as the equation to determine the net cost of new entry (Net CONE) and is used to determine the cost of capacity when applied to the marginal resource that selected for capacity.

these resources based on the net cost of the capacity equation, we also determine that the next least cost capacity resource available to meet near-term capacity needs is a 4-hour battery.

The evaluation of the net cost of the capacity of a 4-hour battery is shown in **Figure 72**. The cost of the capacity of 1kW nameplate is calculated as the sum of all the applicable costs net of any benefits, including tax credits. This value, $75/kW-yr., represents the cost of capacity to procure a 1kW nameplate of batteries. PGE has calculated the cost of capacity to provide 1kW of capacity contribution, the metric that enables a fair comparison across resources. This is done by adjusting the capacity value of the 1kW nameplate by the ELCC of the battery at the marginal quantities of nameplate selected in the Preferred Portfolio. The ELCC of the 232MW nameplate of 4hr battery resource is 52 percent; by dividing $75/kW-yr. by 52 percent we determine that the net capacity cost is $144/kW-yr., which represents the avoided cost of capacity. The ELCC adjustment noted in **Figure 72** reflects the change in value after converting it from a 1kW nameplate to 1kW of capacity contribution, which is the metric that allows for a fair comparison across resources.

Figure 72. Deriving the cost of 1 kW of capacity contribution from a 4-hour battery

Using this new avoided cost of capacity of $144/kW-yr., the following equation can determine the capacity value of a resource at a nameplate value:

$$Capacity\ value\ of\ resource\ A\ =\ Capacity\ contribution\ of\ resource\ A\ *\ \$144/kW-yr$$

Table 51 shows the capacity value of the resources considered within the IRP. For capacity resources, the ELCC and corresponding capacity value (in $/kW-yr.) are shown to indicate the amount of capacity required of each resource to provide 100 MW of capacity contribution.[286] For energy resources, the ELCC and corresponding capacity value (in $/MWh) are shown corresponding to 100-megawatt average (MWa) addition sizes after accounting for the corresponding levelized capacity factors. These values reflect the effects of the declining marginal ELCC curves.

Table 51. ELCCs and associated capacity values[287, 288]

Resource	Annual ELCC for 100 MWa energy addition	Capacity value (2023$/MWh)
Gorge Wind	39%	15
Montana Wind	39%	15
SE Washington Wind	23%	9
Christmas Valley Solar	14%	9
McMinnville Solar	16%	12
Wasco Solar	14%	9
Energy efficiency bin 2	108%	156
Energy efficiency bin 1	118%	169
Christmas Valley 1:1 solar hybrid	78%	112
McMinnville 1:1 solar hybrid	78%	113
Nevada Solar + market access	100%	144
Wyoming Wind + market access	100%	144

[286] *E.g.*, if 500 MW of a capacity resource is required to achieve a 100-MW capacity contribution, the corresponding ELCC at 100-MW capacity contribution equals 20 percent.
[287] Energy efficiency bins represent the aggregate impact of several smaller energy efficiency technologies and strategies that are similar in their levelized costs. These are described in **Section 8.2.1, Additional energy efficiency.**
[288] The annual ELCCs shown in **Table 51** calculated with the average of the seasonal ELCC are for informational purposes and are meant to be directional indicators of capacity value. The actual value of capacity is estimated within portfolio analysis and is dependent on seasonal ELCCs.

10.7 Cost of clean energy

In previous IRPs, production cost and capacity expansion models used to develop portfolio analysis could rely on the market to meet energy needs based on available market prices. House Bill (HB) 2021 sets emissions targets, which are applied as emission constraints in the IRP. These constraints limit access to both specified and unspecified market purchases in the wholesale market that have embedded carbon content.[289] Thus, if the total energy needs of the system surpass the energy generated by both the existing non-emitting resources and the carbon-embedded energy, the model must rely on adding incremental generating resources to meet energy need. This represents a new cost associated with meeting energy needs through non-emitting resources. Conversely, this is a value to resources that avoid this new cost.

Within the IRP's portfolio analysis, these costs are accounted for; decisions about new resource additions fairly estimate all the costs and benefits associated with each potential supply-side option. However, the costs and benefits of many resources are currently estimated outside of the IRP. Current methods estimate energy value in one of two ways:

- The first relies on previous assumptions about market access.[290]
- The second involves determining the net cost of a new off-system VER. However, this option is only applied to resources assuming available transmission capacity.

If either of these methods is applied under the constraints the PGE faces today, they could significantly underestimate the energy value of potential new resources. Doing so would lead to a misidentification of resource economics, resulting in a higher cost system. The existing emissions and transmission constraints signal a need to reassess which values are used when comparing the costs of resources outside the IRP. Additional study is required to understand how estimating a new resource's energy value should be calculated outside the IRP.

10.8 Resource net cost

In **Section 10.6, Capacity value**, PGE applied the concept of the net cost of new entry to assess the capacity value. In this section, we apply the same concept to visualize the relative economics between resources and the dynamics seen within portfolio analysis. This approach was also used in the 2019 IRP and is common industry practice when evaluating resource economics. In this discussion, we define the net cost of new entry as the sum of all costs, such

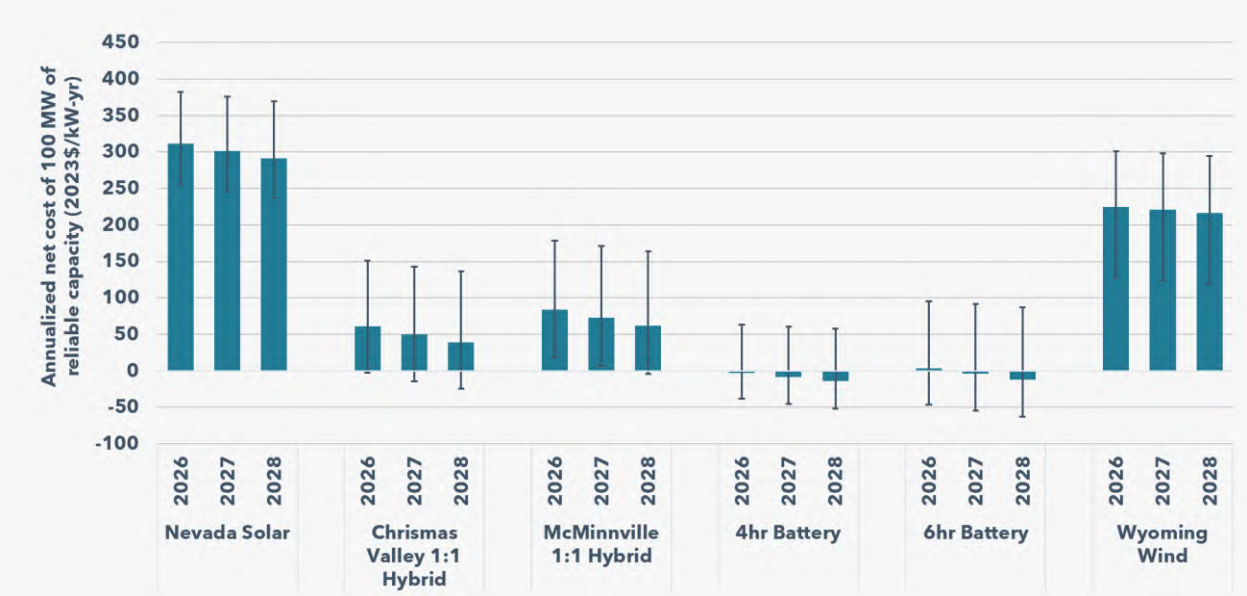
[289] Oregon Department of Environmental Quality (ODEQ) greenhouse gas (GHG) reporting rules (under ORS 468A.280) assign emissions to unspecified sources of energy that serve Oregon retail load.
[290] Generally involving summing the hourly product between generation and market prices.

as fixed, variable and integration costs, net of any benefits, such as tax incentives, and any value provided to the portfolio, including energy, flexibility, rCBI and capacity values. The following sections visualize the net cost of different capacity (in $/kW-yr.) and energy resources (in $/MWh).

10.8.1 Net cost of capacity resources

Figure 73 visualizes the net cost for the different capacity resources available in portfolio analysis. The 1:1 Christmas Valley solar+storage hybrid resource shows a net cost of $61/kW-yr. (2026 COD) while the net cost of a 4hr battery is -$3/kW-yr, highlighting the premium PGE customers would have to pay to procure that resource for capacity over a battery. The relative net costs also highlight the order of selection. For example, absent transmission constraints based only on the information in **Figure 73**, a model adding capacity while minimizing cost would select storage resources before any of the transmission expansion options.

Figure 73. Net cost for 100 MW of capacity contribution of capacity resources by COD[291]



[291] The "Error bars" of the column graph represent the aggregate uncertainty of the costs and benefits when estimating net costs. Uncertainty in costs stem from technology cost futures. Uncertainty in benefits stem from variation in energy value across price futures. The uncertainty in energy value is calculated as the upward and downward semi-deviation of the energy value relative to the Reference Case price future. Price futures are described in **Section 4.5, Uncertainties in price forecasts**.

10.8.2 Net cost of energy resources

The impact of transmission quality and availability is a significant element in the net cost of energy resources. To show this **Figure 74** illustrates the net costs of 100-megawatt average (MWa) of Gorge Wind (2026 COD) with the available transmission, with conditional firm transmission and with the South of Allston (SoA) upgrade cost, respectively. Changes to the transmission quality (from long-term firm to conditionality value firm) decrease the resource's capacity contribution and therefore capacity value. The difference of $6/MWh in the net cost between long-term firm and conditional firm transmission products represents the loss in value when selecting conditional firm transmission for the Gorge Wind resource. Additional costs of transmission upgrades are more intuitive as they increase the net costs of the resource.

Figure 74. Net cost for 100 MWa of Gorge Wind (2026 COD)

Figure 75 shows the net cost of 100 MWa of the new Wyoming transmission option to highlight the costs of new transmission and associated market access costs, showing the large incremental cost PGE customers will likely need to pay to address transmission constraints and access other regional markets. This premium also highlights why distribution-connected resources become increasingly cost-competitive, despite having higher fixed costs than their supply-side counterparts.

Figure 75. Net cost for 100 MWa of Wyoming Wind transmission (2026 COD)

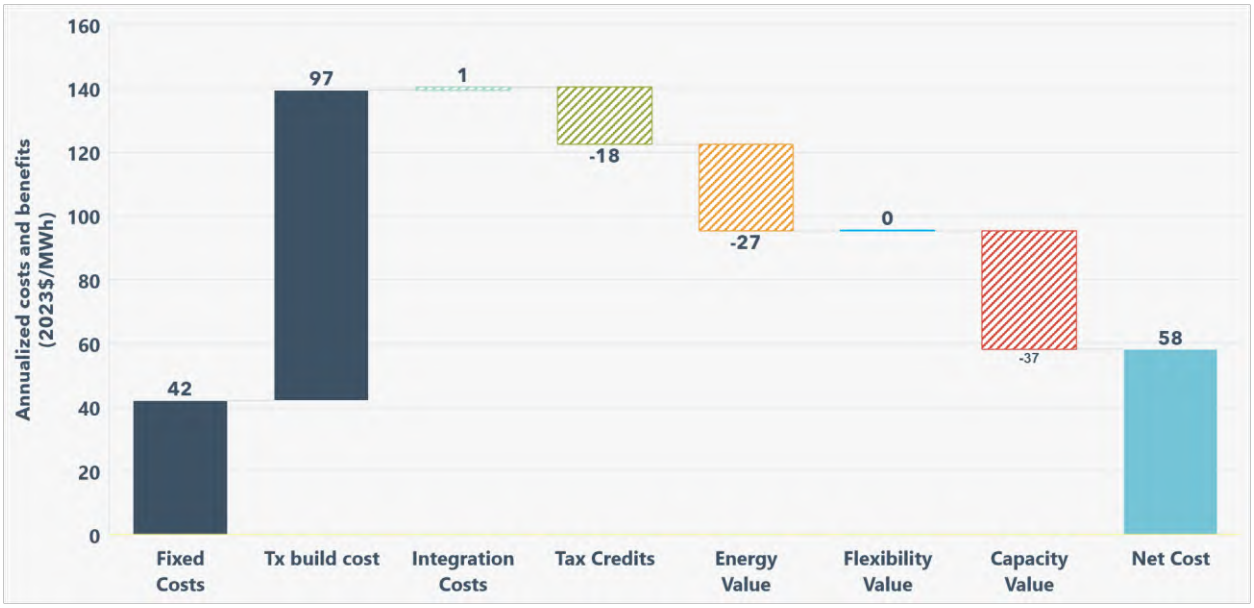
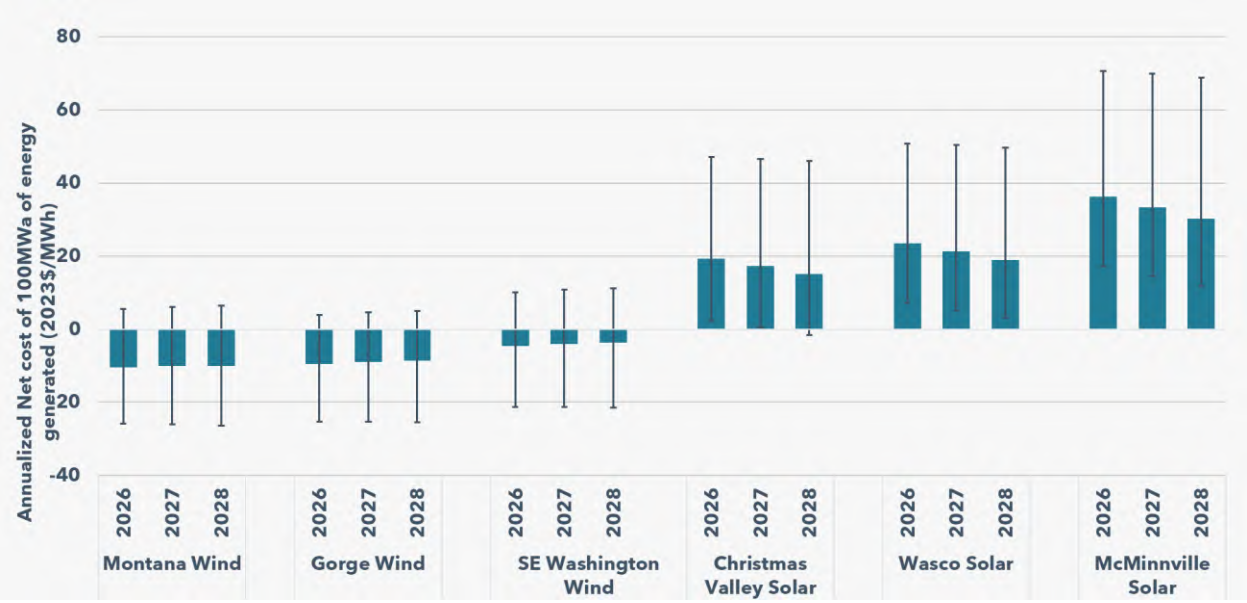


Figure 76, like **Figure 73**, shows the net cost of different resources. However, **Figure 76** focuses on energy resources such as solar and wind and represents the net cost for 100 MWa of a new solar and wind. While net costs of new resources described previously provide helpful insights for understanding the economic tradeoffs between specific resource actions, this simplistic view of resource economics neglects risks associated with future uncertainties and potential interactions between resources and constraints. These are investigated through portfolio analyses described in **Chapter 11, Portfolio analysis**.

Figure 76. Net cost for 100 MWa of solar and wind resources by COD

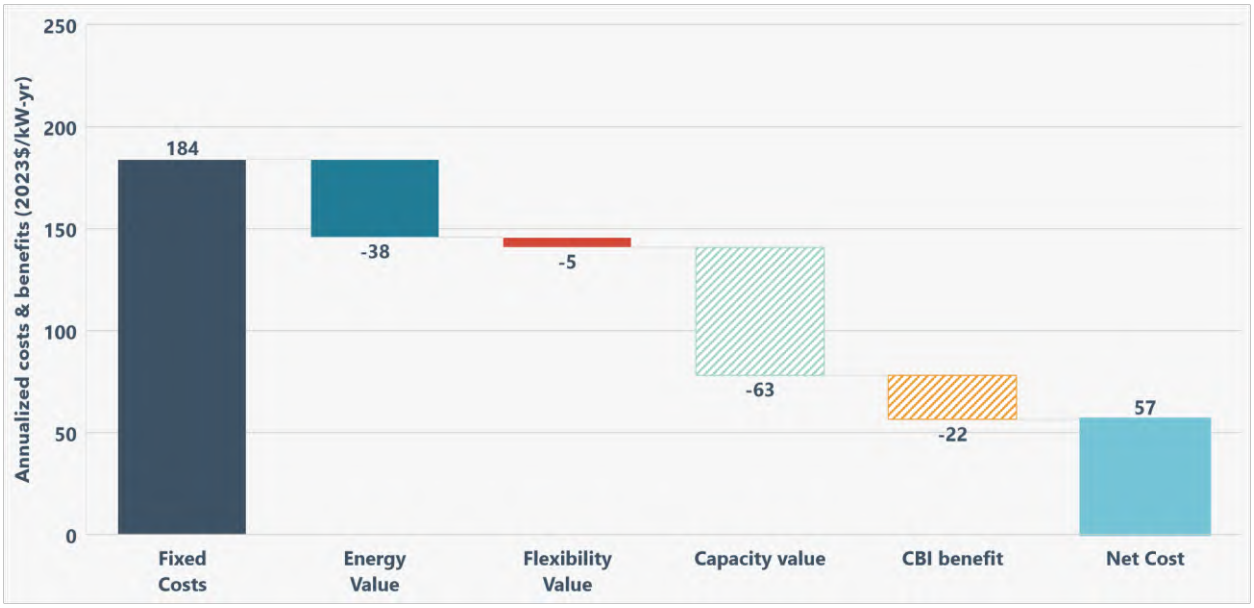


10.9 Resource community benefits indicators

Resource community benefits indicators (rCBI) aim to inform and provide a mechanism to track progress on specific outcomes achieved through CBRE actions. For this first Clean Energy Plan (CEP) filing, PGE developed a 'CBRE favored' approach, like the 1980 Northwest Power Act for energy efficiency.[292] These methods leverage the logic that in planning, we cannot necessarily know which benefits are applicable for each resource as they depend on many factors, such as the resource location and the nature of the resource. For rCBIs, PGE created a CBRE resource within the construct of its resource portfolio that reduces the fixed cost of the three proxy resources evaluated by 10 percent. When considering which resource to select to meet system needs, the capacity expansion model ROSE-E will evaluate the costs and benefits associated with all resources available; the rCBI benefit will lead to the selection of CBREs over an otherwise equivalent resource. **Figure 77** illustrates the impact of the rCBI benefit in the net cost calculation. See **Section 7.1.3, Resource community benefits indicators**, for more details on rCBI.

[292] Northwest Power Act, 16 United States Code Chapter 12H (1994 & Supp. I 1995). Act of Dec. 5, 1980, 94 Stat. 2697. Public Law No. 96-501, S. 885, §839a(4)(D), available at: https://www.congress.gov/96/statute/STATUTE-94/STATUTE-94-Pg2697.pdf

Figure 77. Net cost of a microgrid CBRE (2026 COD)



Chapter 11. Portfolio analysis

The 2023 Integrated Resource Plan (IRP) represents a significant evolution in Portland General Electric's (PGE's) portfolio analysis. PGE has conducted a comprehensive and robust portfolio analysis with stakeholder input to determine a Preferred Portfolio that best balances cost, risk, the pace of decarbonization and community benefits. Portfolio analysis considers needs such as capacity, energy, flexibility and policy as described in **Chapter 6, Resource needs**, and **Chapter 3, Planning environment**, along with resource options such as distributed energy resources (DERs), supply-side options and new transmission options as described in **Chapter 8, Resource options**, and **Chapter 9, Transmission**.

In this chapter, we first describe the portfolio design requirements that underpin portfolio analysis. On this foundation, we explore specific questions and dynamics within this IRP to inform how we can best balance cost, risk, the pace of decarbonization and community benefits. The insights of these investigations form the basis for the Preferred Portfolio, which is described in detail. Lastly, we conduct various sensitivities using the Preferred Portfolio to examine relevant questions in resource procurement.

Chapter highlights

- Portfolios are designed to meet emissions targets, adequacy needs, transmission and procurement constraints and are solved across all 351 permutations of price futures, Need Futures and technology cost futures.
- Portfolio analysis provides insight on the need for transmission, the cost and risk implications of different greenhouse gas (GHG) glidepaths, community-based renewable energy resources (CBREs) and the role for additional DERs in a decarbonized future.
- The insights from these analyses form the basis of the creation of the Preferred Portfolio.
- The Preferred Portfolio represents the combination and timing of resources that best balance costs, risk, emission reductions and community benefits for customers under the assumptions used in the IRP process.

11.1 Portfolio design requirements

PGE designed 39 distinct portfolios to test key questions concerning potential resource acquisition strategies. Each portfolio was analyzed across a wide range of scenarios varying combinations of potential future conditions for need, price and technology costs using the capacity expansion model ROSE-E.[293] For each portfolio, ROSE-E is given a fixed set of required resource acquisitions that meet a portion of needs. ROSE-E determines the optimal combination of resources to fill the remaining resource need while minimizing system costs for each of the 351 scenarios described in **Section 4.6, Addressing uncertainties**, subject to a variety of constraints.[294] Using this approach, 117 resource buildouts are produced for each portfolio, including one for the Reference Case scenario, which models Reference Case conditions for need, price and technology cost futures.[295]

ROSE-E has the ability to select new resources from a subset of the options described in **Chapter 8, Resource options**, and the transmission options described in **Section 9.4.1, Proxy transmission options identify transmission need**, and bases its decision on the economics presented in **Chapter 10, Resource economics**. To aid the reader, **Table 52** defines key terms within portfolio analysis.

Table 52. Defining key terms within Portfolio Analysis

Terms	Description
Portfolio	A fixed set of resource decisions set in all scenarios. The model (ROSE-E) creates resource buildouts around those choices in each scenario.
Scenario	Refer to elements that are varied within portfolio analysis resulting in multiple resource buildouts. Some of the predefined scenarios are need, technology cost, price, hydro.
Resource buildout	Least cost set of incremental resource additions given a set of specific input conditions such as a portfolio and scenario.
Portfolio sensitivities	Sensitivities test the robustness or provide additional information on the Preferred Portfolio by forcing changes in resource constraints or other inputs.

[293] ROSE-E was developed prior to the 2019 IRP and was used to conduct portfolio analysis in that filing. More information about the use of ROSE-E in the 2023 IRP can be found in **Appendix H, 2023 IRP modeling details**. Details on the use of ROSE-E in the 2019 IRP: *In the Matter of Portland General Electric Company, 2019 Integrated Resource Plan*, Docket No. LC 73, Order No. 20-152 (May 6, 2020), available at: https://apps.puc.state.or.us/orders/2020ords/20-152.pdf

[294] A small number of portfolios designed to test optimization assumptions differ from this protocol by either minimizing cost only with respect to the Reference Case future, or only for a subset of year of the analysis.

[295] System costs are evaluated across futures for price, hydro condition, technology cost and need (13 x 3 x 3 x 3 = 351), while resource buildouts vary across futures for price, and technology cost only (13 x 3 x 3 = 117).

Portfolios are subject to several constraints described in the following sections that ensure portfolios add sufficient resources to meet forecast capacity and energy needs and comply with all applicable regulatory requirements. All portfolios are designed to meet a uniform set of constraints and a default set of assumptions except where individual constraints and assumptions are altered on a portfolio-group-specific basis to test questions of interest. Using a consistent set of assumptions within groups of portfolios allows comparison of resource buildouts and portfolio scoring metrics while isolating the impacts of the specific assumptions being tested.

11.1.1 GHG emissions

Greenhouse gas (GHG) emissions limits are imposed on each portfolio consistent with House Bill (HB) 2021 requirements, limiting GHG emissions to a maximum of 1.62, 0.81 and 0 million metric tons in 2030, 2035 and 2040, as shown in **Figure 26** in **Section 5.1, HB 2021 targets**. HB 2021 does not explicitly set GHG limits for years prior to 2030 but does require continual progress toward meeting the clean energy targets of 2030.[296]

Determining the rate of GHG emissions reductions or GHG glidepath that best balances cost and risk is evaluated in portfolio modeling, which are described in **Section 11.4.1, Decarbonization glidepath portfolios.** Additional information about GHG emissions in the IRP is in **Chapter 5, GHG emissions forecasting**.

11.1.2 Resource adequacy

All portfolios are constrained to meet PGE's resource adequacy requirements in both summer and winter during all years. The calculation of capacity need is described in **Section 6.6, Capacity need**. Capacity needs in portfolio construction are met by adding new resources, which provide the capacity contribution described in **Section 10.5, Resource capacity contribution**.[297]

[296] HB 2021, Section 4 (4)(e), available at: https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2021/Enrolled

[297] In addition to the new resource options described in **Section 8.5, Post-2030 resource options**, each portfolio is given 200 MW of capacity and 90MWa of energy in the years 2026 through 2030 to represent the expected extension of a portion of PGE's existing non-emitting capacity contracts.

11.1.3 Generic resources

Due to the presence of transmission constraints, the quantity of proxy resources available for selection in the model is insufficient to meet energy and capacity needs through 2043 in most portfolios. To allow the model access to the energy and capacity needed beyond the amount available through proxy resource options, all portfolios have access to two 'Generic' non-emitting on-system resources that are not subject to transmission constraints.

- 'Generic Cap' provides 100 percent effective load-carrying capacity (ELCC) and has no associated energy.
- 'Generic VER' provides both energy and capacity, with an ELCC curve and capacity factor defined by a weighted average of proxy variable energy resources (VER) in the Preferred Portfolio.

The generic resources have high costs so that they are available for the model to meet needs without competing economically with proxy resource options. Generic resources have fixed costs equal to 105 percent of the highest-cost proxy resource option (NV Tx). The model has access to 500 megawatts (MW) of each generic resource each year starting in 2026. All else equal, portfolios that require earlier or heavier reliance on generic resources will have increased costs relative to others.

11.1.4 Renewable portfolio standards

All portfolios presented in the IRP comply with Oregon's renewable portfolio standard (RPS) requirements described in **Section 6.7, RPS need**, through the entire planning horizon. ROSE-E simulates the generation, banking and retirement of Renewable Energy Certificates (RECs) from RPS-eligible resources and enforces the five-year lifetime limit on banked RECs consistent with Senate Bill (SB) 1547. For each portfolio to meet RPS requirements in each Future, the retired RECs in each year must meet or exceed the RPS obligation in that year. The resulting RPS position of the Preferred Portfolio is shown in **Section 11.5.2, Resulting RPS position**. With the introduction of HB 2021, the amount of non-emitting resources that need to be built to comply with emissions targets of HB 2021 is larger than the amount needed to comply with RPS requirements. Accordingly, RPS compliance is not forecasted to drive resource additions in this IRP.[298]

[298] It could be the case that PGE acquires non-emitting generation that helps move towards HB 2021 emissions targets but not RPS obligations. However, given the limited availability of non-emitting but non-RPS-qualifying generation the sizeable forecasted additions of RPS-qualifying generation (shown in **Section 11.5.2, Resulting RPS position**, and the size of PGE's REC bank it is a reasonable conclusion that RPS compliance will not drive future resource acquisition.

11.1.5 Energy position

To ensure that incremental resource additions do not put PGE's portfolio in a consistently long position (generating more energy than is needed to serve customers), the amount of energy added by new resources in portfolio modeling is constrained to not exceed PGE's forecasted net market position by more than 100-megawatt average (MWa) in any given year after 2026. The energy surplus constraint is relaxed between 2024-2026 to allow for a long energy position before adding new resources. In addition, the energy surplus constraint is relaxed in certain years for some portfolios to allow the testing of resource options that would otherwise violate the constraint or to avoid unintended confounding effects on resource buildouts that prevent the comparison of portfolios within a given portfolio category. In preventing the building of an overly long portfolio, the energy surplus constraint also helps ensure that the resource buildout contains an appropriate amount of dispatchable capacity resources and is not overly reliant on variable energy resources.

11.1.6 Procurement constraints

PGE has not imposed general limits on the total amount of resources that can be added each year, as PGE seeks to streamline the existing procurement process. To test the impact of procurement limitations, resource limitation constraints are imposed as part of sensitivity analysis, as described in **Section 11.7, Sensitivities**.

11.1.7 Transmission constraints

As renewable energy development grows around the West, the availability of transmission to move energy from the point of generation to load centers is becoming scarce (see **Chapter 9, Transmission**, for more detail). To account for this increasingly important consideration in the siting of resources, we incorporated contractual transmission constraints in portfolio analysis. A detailed description of the methodology, including derivation of transmission inventories, can be found in **Appendix H, 2023 IRP modeling details**.

11.2 Portfolio scoring

Portfolios were evaluated based on the scoring metrics described in **Table 53**. Comparing portfolios consistently based on these metrics allows PGE to quantify the impact of changes in key assumptions on portfolio outcomes. The direction and magnitude of change in these metrics generate beneficial insights that ensure the Preferred Portfolio and Action Plan are robust and represent the best combination of costs and risks.

Table 53. Portfolio scoring metrics

Metric	Description	Units
Cost	Net present value of revenue requirement (NPVRR), calculated for each of the 351 future scenarios and presented for the Reference Case for the analysis timeline (2024-2043).	Million 2023$
Variability	Semi-deviation of NPVRR across all futures, relative to the Reference Case. This metric captures the potential variation in cost outcomes across futures, considering only futures in which NPVRR exceeds the Reference Case. Portfolios with low variability scores tend to provide more cost certainty and lessen the customer's impacts of higher-than-expected cost conditions.	Million 2023$
Severity	The tail value at risk (TailVAR) at the 90th percentile of the NPVRR across futures. This metric measures the potential magnitude of very high-cost outcomes across all futures. Portfolios with low severity scores tend to have less costly worst-case scenarios for customer cost impacts.	Million 2023$
Community Benefits	This metric reflects the portfolio benefits associated with the CBRE additions that deliver community benefits. These benefits are further described in Section 14.2.3.2, CBI community engagement.	N/A

11.3 Yearly price impacts

In this IRP PGE has developed a new model to estimate the annual price impacts of a given portfolio.[299] The Annual Revenue-requirement Tool (ART) was created to provide an additional dimension in the analysis of forecasted system cost when comparing different portfolios. The ART was developed specifically for IRP purposes to evaluate yearly price impacts of planned proxy new resource additions. The model uses the existing and

[299] Developing this model satisfied the 2019 IRP Commission requirement "...PGE will need to continue to evaluate and balance the tradeoffs between more certain near-term rate impacts and less certain long-term projected cost savings.", Docket LC73, Order No. 20-152 at 19, available at: https://apps.puc.state.or.us/orders/2020ords/20-152.pdf, and ORS 469A.400 469.475, Section 4(4)(b) Clean Energy Plans; electric companies, from the CEP as detailed in Chapter 1, topic 3 of the UM 2225 Investigation into Clean Energy Plans Workplan Update and Straw Proposal, regarding annual metrics measuring the impacts of actions, at 7-8, available at: https://edocs.puc.state.or.us/efdocs/HAH/um2225hah11736.pdf.

incremental proxy resource costs described in **Chapter 9, Transmission** and Reference load presented in **Chapter 6, Resource needs**.

The model incorporates the impact of market sales on an annual basis and includes different combinations of ownership structures and tax incentives modeled for each portfolio.[300] Market purchases and thermal sales are calculated on an annual basis within the GHG Intermediary model and imported to ART. Further, ART only focuses on existing and new generating resources, including the associated transmission costs. Estimates do not include costs from the rest of PGE, such as those associated with administrative costs, grid modernization, other transmission and distribution maintenance and upgrades, wildfire mitigation or actual generation costs. Caution is warranted in interpreting these estimates, as these values reflect a change in forecasted annual costs of real and proxy generating assets that only represent a subset of PGE's total annual cost. Accordingly, these yearly price impacts do not represent actual customer price impacts (expressed either as total or a percent) as they only focus on planned generation cost changes and do not incorporate any other cost changes across PGE.

11.4 Portfolio analysis results

PGE has tailored the portfolio analysis in the 2023 IRP to answer key questions in resource planning and leverage insights from those answers in the creation of the Preferred Portfolio. These key questions are explored through different portfolio categories, comprised of multiple portfolios hand-designed to explore the impact of specific potential PGE actions or changes to the operational, economic, and/or policy landscape within which PGE operates. These categories are presented and described in **Table 54**. Some portfolios that PGE cannot effectuate have been intentionally developed to study specific questions. These portfolios are listed as informational in the relevant portfolio categories.

Table 54. List of portfolio categories and their purpose

Portfolio categories	Purpose
Decarbonization glidepath	Explore the relationship between the rate of emissions reduction to serve retail load, cost and risk
Transmission	Study the need for transmission, the timing of this need and the corresponding magnitude needed over time to reliably decarbonize

[300] Modeling assumption of the ownership structures do not impact or reflect future procurement approaches or prejudge outcomes of future procurement processes.

Portfolio categories	Purpose
Community-Based Renewable Energy (CBRE)	Explore the relationship between costs, risk and community benefits
Additional Energy Efficiency and Demand Response	Determine if and how the role of these resources could change with the changing planning environment
Optimized	Explore the relationship between minimizing costs in the short-term and the entire planning horizon and cost of constraining the model
Targeted policy	Inform stakeholder discussions on specific policy questions
Emerging technology	Understand the potential impacts of emerging technologies

All portfolios assume that a portion of PGE's existing long-term contracts for energy and capacity from non-emitting sources set to expire at the end of 2025 are renewed through the end of 2030, representing 90 MWa of energy and 200 MW of capacity contribution annually.

11.4.1 Decarbonization glidepath portfolios

PGE explored the relationship between the rate of emissions reduction to serve Oregon retail load, cost and risk with the Decarbonization Glidepath portfolios (**Table 55**). These portfolios are designed to meet or exceed HB 2021's GHG emissions targets using a variety of glidepaths or trajectories. Decarbonization Glidepath portfolios have identical assumptions and inputs aside from their differing GHG emissions reduction pathways to isolate insights on the impacts of the pace of decarbonization on portfolio costs and risks.[301]

The 'Linear decline, 'Front-loaded decline' and 'Back-loaded decline' portfolios meet HB 2021 emissions reductions targets using different rates of emissions reductions ("glidepaths") from 2026-2030 (as shown in **Table 55**) and converge on a single glidepath thereafter.

[301] Because these portfolios have different energy position inputs, they are not subjected to the energy surplus constraint described in **Section 11.1.5, Energy position**. For the purposes of comparison across these portfolios, the imposition of an energy surplus constraint introduces confounding impacts on resource additions, preventing level comparison.

Portfolios '100 percent emissions reduction by 2035' and 'Two-yr forward shift in targets' rely on glidepaths that achieve emissions targets ahead of regulatory deadlines.

Table 55. List of decarbonization glidepath portfolios

Portfolios	Portfolio condition
Linear decline	Meeting 2030 targets by adopting a linear path in emissions reduction (each year must provide the same reduction in emissions as the previous year)
Front-loaded decline	Meeting 2030 targets by front-loading emission reduction (each year must provide half the reduction in emissions of the previous year)
Back-loaded decline	Meeting 2030 targets by rear-loading emission reduction (each year must provide twice the reduction in emissions of the previous year)
100% emissions reduction by 2035	Achieving 100% GHG emission reduction by 2035
Two-yr forward shift in targets	Achieving each carbon target two years ahead of schedule 80% by 2028, 90% by 2033 and 100% by 2038

Figure 78 visualizes the annual emissions of each of the decarbonization glidepath portfolios. Differences in the rate of decarbonization across the five portfolios can be seen starting in 2026.[302] When emissions targets are attained ahead of schedule, as in '100 percent emissions reduction by 2035' and 'Two-yr forward shift in targets', cumulative emissions from 2024-2043 are reduced relative to on-time attainment with a linear glidepath (**Figure 79**). Amongst the three portfolios that achieve targets on-time with different glidepaths to 2030 ('Linear decline', Front-loaded decline' and 'Back-loaded decline'), the front-loaded glidepath produces the lowest cumulative emissions throughout the portfolio modeling time-horizon and the back-loaded decline in produces the largest quantity of cumulative emissions (**Figure 80**). The linear emissions reduction glidepath falls in the middle, producing approximately 28.68 MMT CO2e throughout the planning horizon (**Figure 78**). **Appendix O, Thermal Operations/ Output** displays total emissions associated with serving retail load and market sales in each of these three decarbonization glidepaths.

[302] Forecasted emissions for 2023 through 2025 are based on the expected impact of the 2021 All-Source request for proposals (RFP), PGE's Green Future Impact (GFI) program, load growth and other factors. Forecasted emissions from 2026 onwards (when portfolios are able to add incremental resources) are from one of the five tested glidepaths.

Figure 78. Decarbonization glidepath portfolios

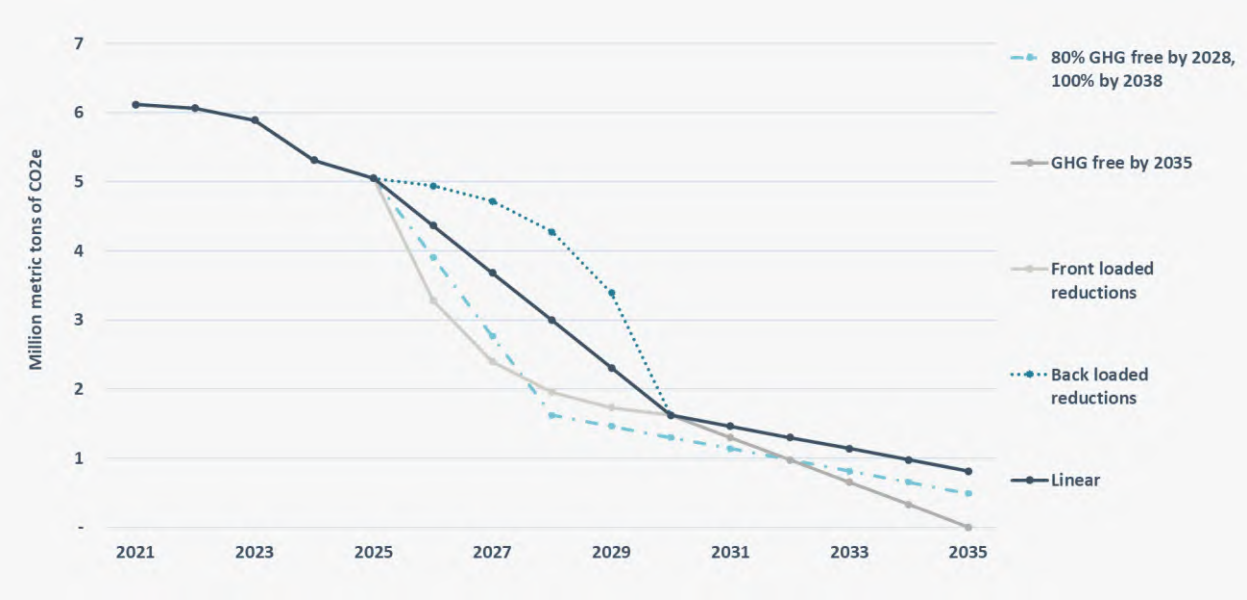


Figure 79. Cumulative emissions 2024-2043, accelerated decarbonization glidepath portfolios

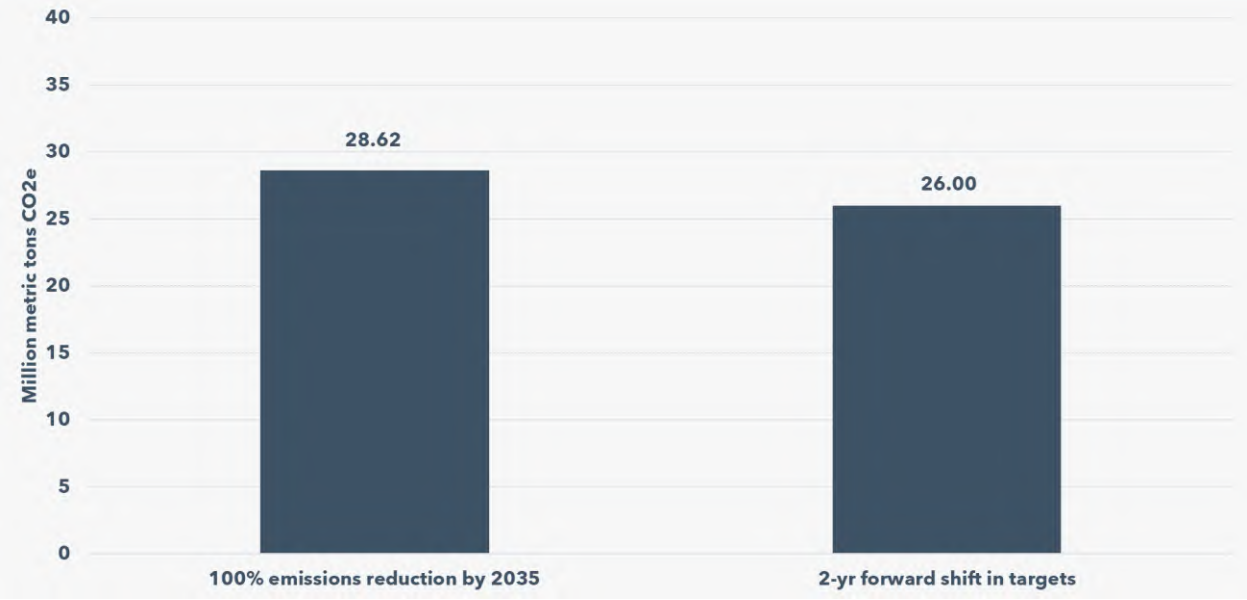
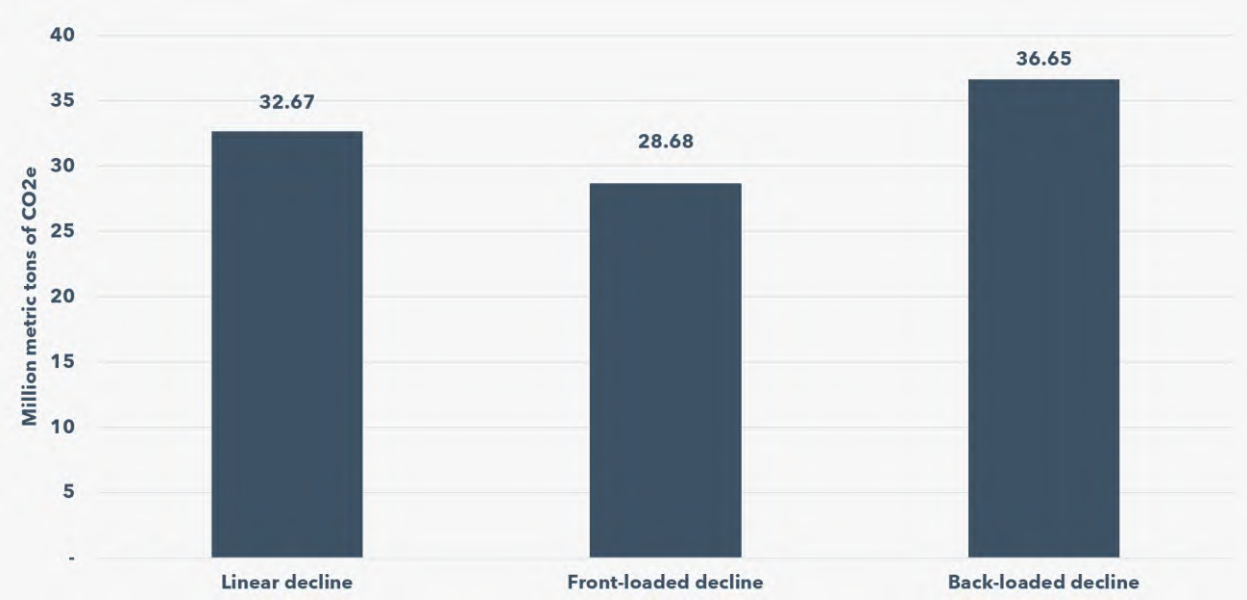


Figure 80. Cumulative emissions 2024-2043, decarbonization glidepath portfolios



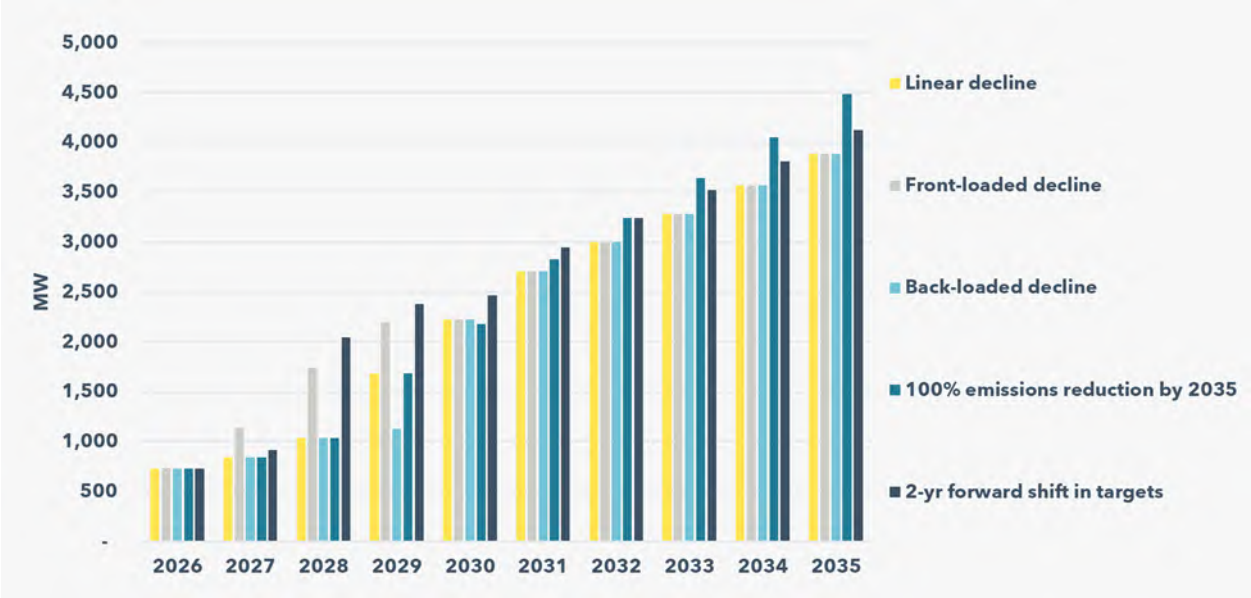
The lower cumulative emissions associated with accelerated rates of decarbonization come with tradeoffs in terms of portfolio cost and risks. Accelerated decarbonization increases the near-term Reference Case need for renewable resource additions (**Figure 81**). The difference between renewable additions in the 'Linear decline' portfolio and the 'Two-yr forward shift in targets' portfolio shows that accelerated decarbonization can increase the need for renewable procurement by over 1,000 MW by 2028 in the Reference Case. The front-loaded decline portfolio also increases procurement need through 2028, requiring 701 more MW than linear decline portfolio by 2028. The energy need in the '100 percent by 2035' glidepath begins to increase relative to the linear glidepath in 2031 and it requires larger energy procurement in 2031-2039 as a result, adding 605 MW more than the linear glidepath by 2035.

'Two-yr forward shift in targets' is unable to meet energy needs without access to the generic VER resource in 2029, showing that in a world with limitations on access to transmission, faster decreases in emissions in the near-term would further increase dependence on transmission and/or emerging technologies that might not be proven, which adds additional risk. While achieving early attainment of HB 2021 targets is possible without utilizing the generic resources in the pre-2030 timeframe in the '100 percent emissions reduction by 2035' portfolio, the need to add resources earlier in the planning-horizon results in increased costs compared to the three glidepaths that achieve compliance on-time.

On-time achievement of targets relying on a back-loaded glidepath to 2030 may also increase procurement risk relative to a linear glidepath, increasing the need to rely on large resource additions concentrated in fewer years approaching 2030. This includes

uncertainties in available transmission inventories, procurement delays and other supply chain constraints, operational risks associated with adding large quantities of resources in a small amount of time.

Figure 81. Renewable resource buildout of decarbonization portfolios



Comparison of cost and risk metrics shows that the portfolios that meet HB 2021 targets early (100 percent emissions reduction by 2035 and Two-yr forward shift in targets) have increased system costs relative to meeting targets on schedule using the linear-decline glidepath (**Figure 82**). The increase in cost is driven by the earlier resource additions required for early attainment. This increases costs due to two factors; the discounting of values in the calculation of net present value revenue requirement (NPVRR), which weights the impact of near-term costs more heavily than costs accrued later in time, and the declining cost curves of new resource options (as described in **Chapter 8, Resource options**). The cost and risk tradeoff associated with faster emissions declines can also be seen in comparison between 'Back-loaded decline' and 'Front-loaded decline', with 'Front-loaded decline' being the most expensive and most variable as a result of earlier resource additions and 'Back-loaded decline' being the least expensive and least variable due to later resource additions (**Figure 83**). The linear glidepath in 'Linear decline' falls in the middle for both cumulative emissions and cost and risk metrics.

Figure 82. Cost and risk of accelerated decarbonization glidepath portfolios

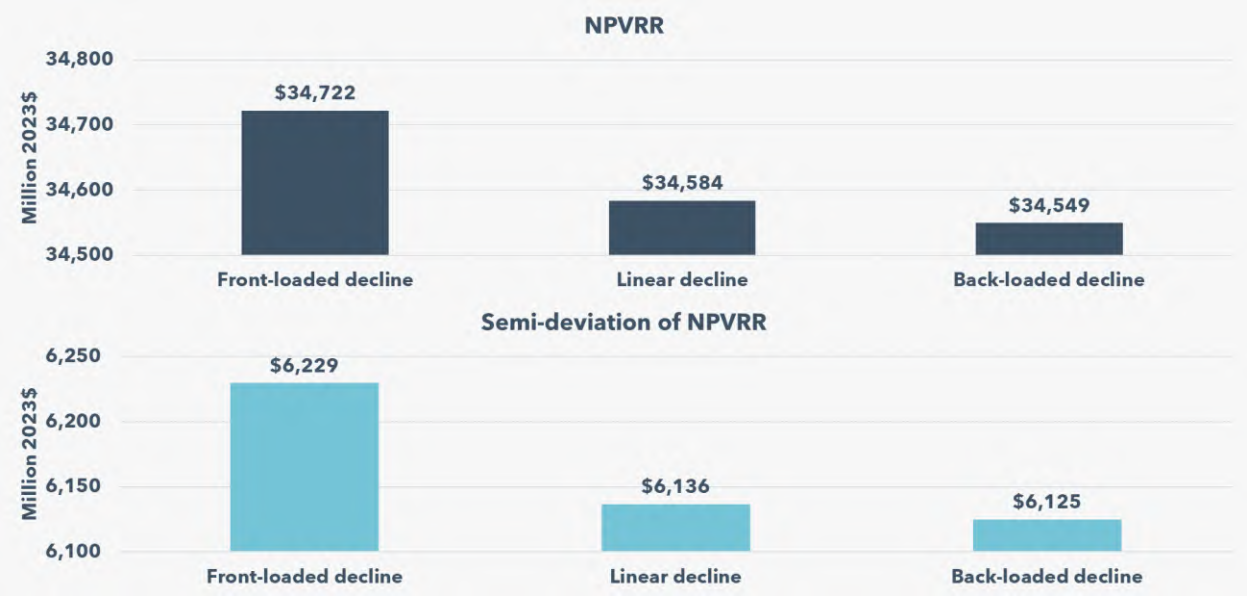
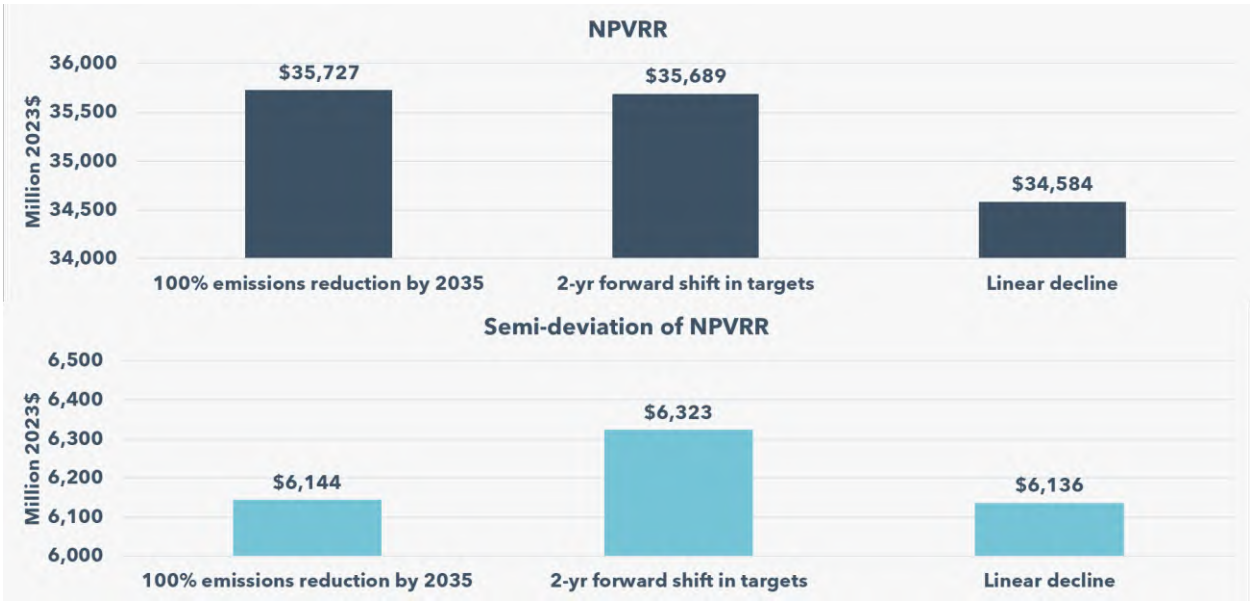


Figure 83. Cost and risk of decarbonization glidepath portfolios



Given the tradeoffs between rate of emissions reduction and portfolio cost and risk, the findings of this analysis indicate that the 'Linear decline' best balances the costs and multiple sources of risk with the rate of emissions reductions to meet HB 2021 targets by 2030 and it is used as the default in all other portfolios, including the Preferred Portfolio.

11.4.1.1 Decarbonization glidepath annual price impacts

The forecasted difference in yearly cost impacts (associated with existing and incremental generation) per megawatt hour (MWh) of retail load between the linear decarbonization glidepath and the front and back loaded decarbonization glidepath can be seen in **Figure 84**.[303] Positive values represent higher costs relative to linear glidepath and negative values represent lower costs relative to linear glidepaths. The differences in portfolio costs are projected through the planning horizon starting in 2026, the first available year of incremental resource additions.

The higher costs of the front loaded decarbonization glidepath are primarily seen in the near-term with the additional costs through 2030. Additional costs in the 2037 through 2039 reflect the earlier expiration of production tax credits (PTC) in the front-loaded portfolio relative to the linear decline portfolio, which is a smaller determinant in decision making. The lower costs of the back-loaded decarbonization glidepath highlight a similar relationship, showing lower costs with a later buildout in the 2020's. These yearly cost forecasts support the finding described previously that GHG emission reductions lead to cost increases.

Figure 84. The annual ($/MWh) impact of Decarbonization Glidepath portfolios through 2035

[303] **Addendum: PGE CEP Data Template** contains the annual price impact in $'s and the annual price impact per unit retail sales ($/MWh) through the planning horizon for each portfolio

11.4.2 Transmission portfolios

PGE designed a set of transmission portfolios to understand the quantity and timing of need for transmission to reliably decarbonize the system and test the impact of assumptions about transmission on other resource choices (described in **Table 56**). To isolate the effect of differences in assumptions related to transmission resource buildout and cost and risk metrics, these portfolios contain otherwise consistent assumptions (i.e., availability of other resources such as CBREs and additional EE and DERs and a linear GHG reduction glidepath).

Table 56. List of transmission portfolios

Portfolios	Portfolio condition
No Transmission (Tx) constraints (informational)	No transmission constraints imposed
No upgrades (informational)	No transmission upgrades or build options available
Unconstrained SoA (informational)	Unlimited South of Alston (SoA) transmission access beginning in 2027
Unconstrained SoA Plus (informational)	Unlimited SoA transmission access beginning in 2027 New transmission options to WY and NV are available in 2026
SoA in 2027 plus	SoA upgrade unlocks 400 MW of IRP proxy resources in the PNW in 2027 New transmission options 400 MW each to WY and NV are available in 2026
SoA in 2027	SoA upgrade unlocks 400 MW of IRP proxy resources in the PNW in 2027
SoA in 2029	SoA upgrade unlocks 400 MW of IRP proxy resources in the PNW in 2029
WY in 2026	New transmission option 400 MW to Wyoming in 2026
NV in 2026	New transmission option 400 MW to Desert Southwest in 2026
WY in 2028	New transmission option 400 MW to Wyoming in 2028
NV in 2028	New transmission option 400 MW to Desert Southwest in 2028

11.4.2.1 Informational transmission portfolios

The informational portfolio 'No Tx Constraints' envisions a world where PGE operates free from contractual limitations in the transmission system. As shown in **Figure 85**, the cost of building a portfolio that meets PGE's resource needs appears to be relatively low cost when the contractual transmission landscape is not accounted for. The large amount of renewable additions that the model selects in the absence of transmission constraints (**Figure 86**) and the low portfolio cost of the 'No Tx Constraints' portfolio (**Figure 85**) suggests that in the absence of transmission constraints, renewables offer the lowest-cost method to decarbonize when paired with sufficient dispatchable capacity resources to meet reliability needs. When compared to other transmission portfolios, PGE finds that the inclusion of transmission constraints increases costs, an intuitive finding because the model has fewer resource options to choose from to meet capacity and energy needs.

In contrast, the 'No upgrades' portfolio evaluates a scenario where no transmission upgrades are actionable to PGE and where PGE must rely on the current estimated available contractual transmission capacity.[304] The resulting resource buildout reveals that without access to additional transmission, the model must rely relatively heavily on the generic resources by 2030 (**Figure 86**), an outcome that results in substantially increased estimated costs and risk (**Figure 85**). Given the uncertainties surrounding the cost and availability of the resources that would be added to fill this need, this also would require further study on their technical and economic feasibility. These results also demonstrate that the current forecasts of transmission capacity are insufficient to meet system needs over the planning horizon even after acquiring the entirety of the available potential for CBREs and cost-effective DERs.

[304] Information on the creation of these estimates can be found in **Appendix H.7, BPA transmission in ROSE-E.**

Figure 85. Cost and risk of informational transmission portfolios

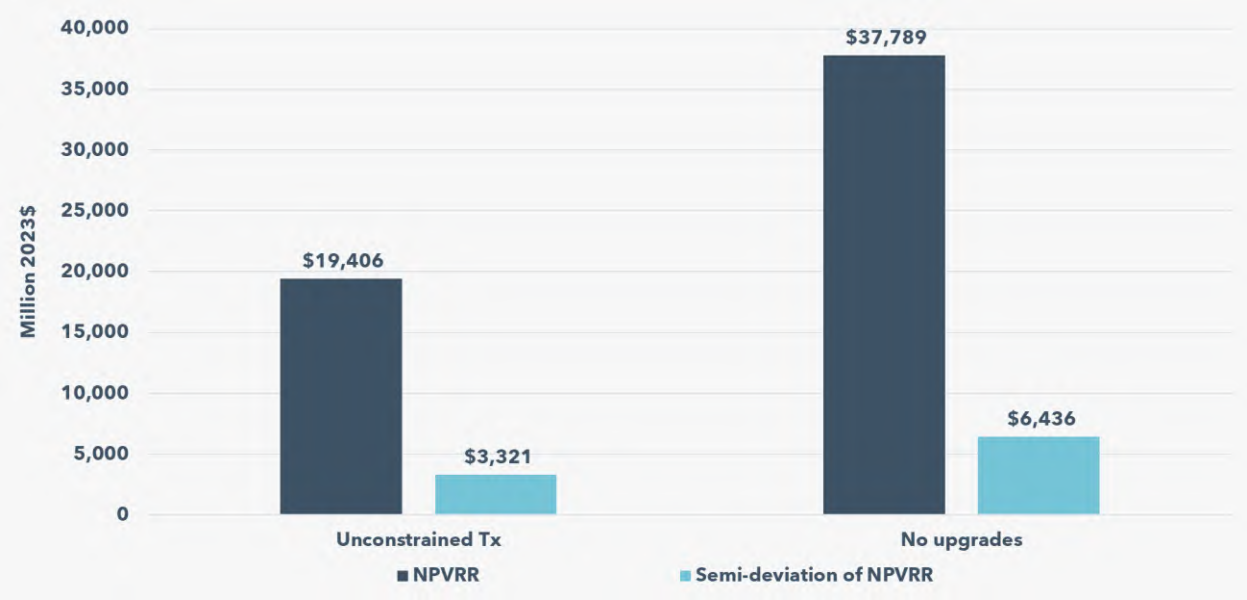
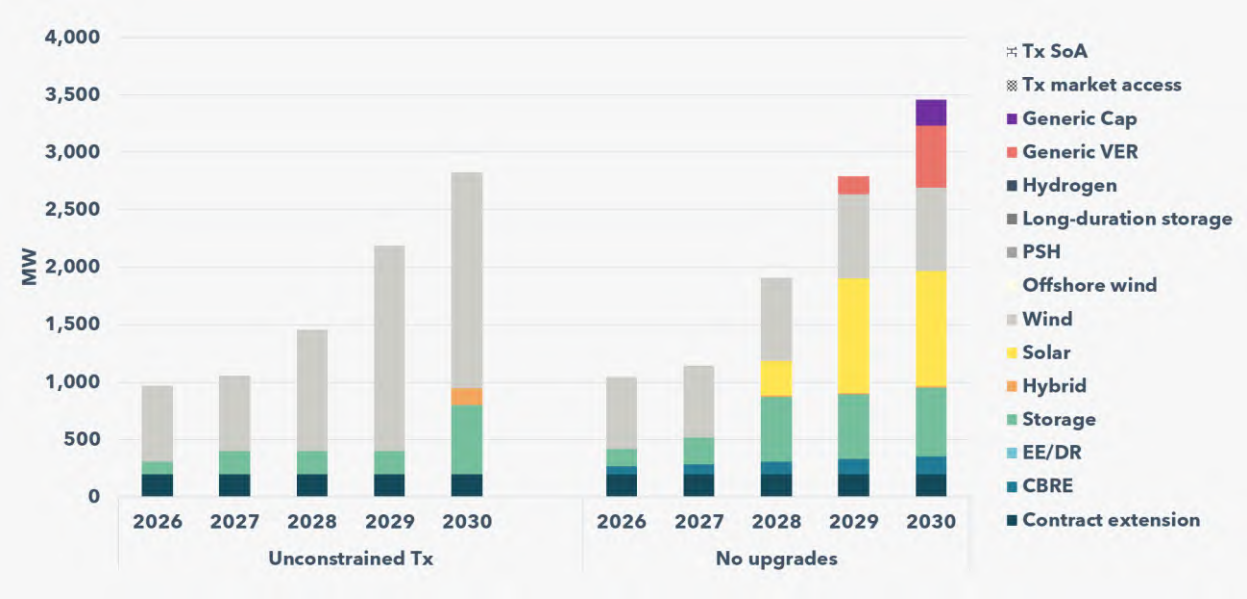


Figure 86. Resource buildout of informational transmission portfolios



With the inclusion of the generic on-system resources noted previously, the 'No Upgrades' portfolio can demonstrate the quantities of additional transmission capacity needed to reliably decarbonize. After accounting for the magnitude of the distribution connected resources that can minimize transmission need, the portfolio has identified the timing and magnitude of the most conservative perfect transmission required over the next 20 years

(**Table 57**).[305] Thus, this portfolio shows that in the absence of a technology breakthrough that yields a low-cost and scalable resource, there is a need to invest in incremental transmission to PGE. Additionally, it also shows that even after accounting for the impact of additional DERs beyond the Distribution System Plan (DSP), the transmission need is significant. This underscores that in the absence of investments in transmission, PGE would not be able to reliably decarbonize and meet the 2030 targets of HB 2021.

Table 57 shows the quantity of transmission that would be required corresponding to the quality of resources available. Resources that can provide significant energy and capacity benefits require the least amount of new transmission, while other resources may increase transmission needs. As these results emphasize, based on the type and quality of resources available, upwards of 800 MW of transmission may be needed as soon as 2030. The appropriate combination of transmission upgrades vs. new transmission required is explored in the following section.

Table 57. Estimated Reference Case transmission need

Year	Generic VER	Generic capacity	Potential transmission need (MW)
2026	-	-	-
2028	-	-	-
2029	159	-	159
2030	541	228	541-768
2035	2,199	807	2,199-3,005
2040	4,285	3,183	4,285-7,468

[305] Assuming that all remaining system needs are met through transmission. Other post-2030 resource options may fill some or all of this need, as discussed in **Section 8.5, Post-2030 resource options**.

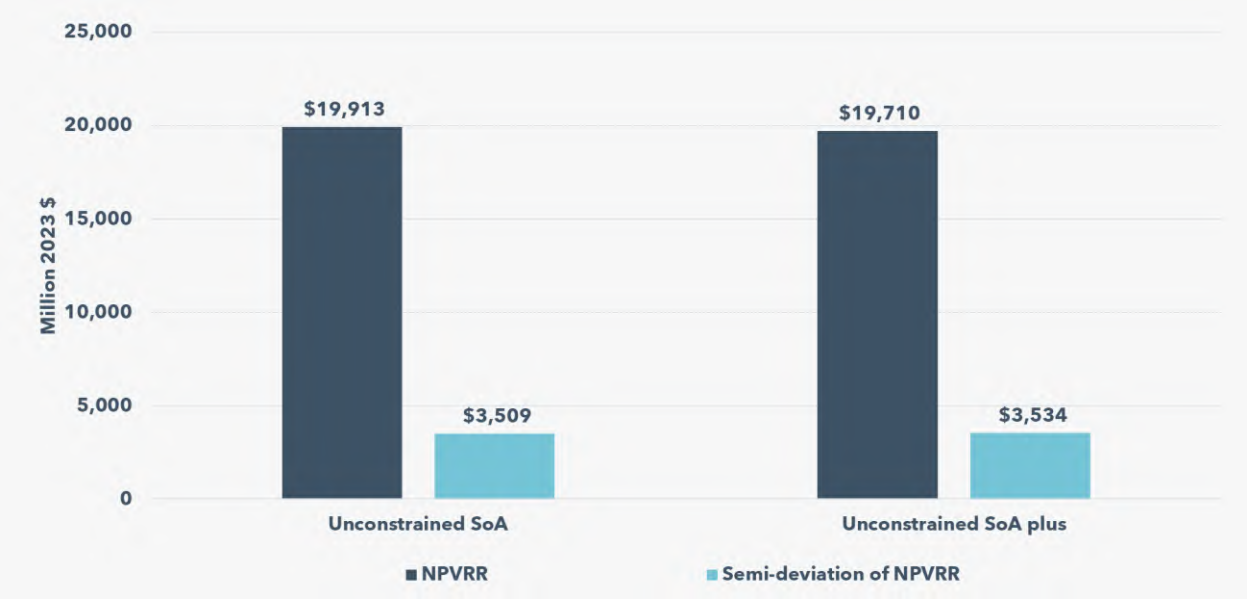
11.4.2.2 Transmission diversity portfolios

In the 'Unconstrained SoA' portfolio, the model has unlimited access to add transmission access to Oregon, Washington and Montana proxy renewable resources (Pacific Northwest [PNW] proxy resources) that are otherwise limited by the contractual transmission landscape, beginning in 2027. In the 'Unconstrained SoA Plus' portfolio, the model has the same access to reduce SoA congestion, plus access to 400 MW each of the WY and NV transmission expansion options beginning in 2026.

The resulting Reference Case resource buildout is very similar through 2030 for both portfolios, with the model choosing to rely on the SoA upgrade and not selecting WY or NV transmission expansion. However, later in the planning horizon, the model takes advantage of access to the WY and NV transmission expansion options in 'Unconstrained SoA Plus', adding 600 MW by 2040. As a result, 'Unconstrained SoA Plus' has a lower cost (**Figure 87**).

These resource buildout results demonstrate that significantly increasing access to PNW proxy resources helps delay the need for investments in more expensive transmission expansion options. Additional transmission options are forecasted to be an effective method to reduce both cost and risk, especially in higher-Need Futures.

Figure 87. Cost and risk of transmission diversity portfolios



11.4.2.3 Transmission timing portfolios

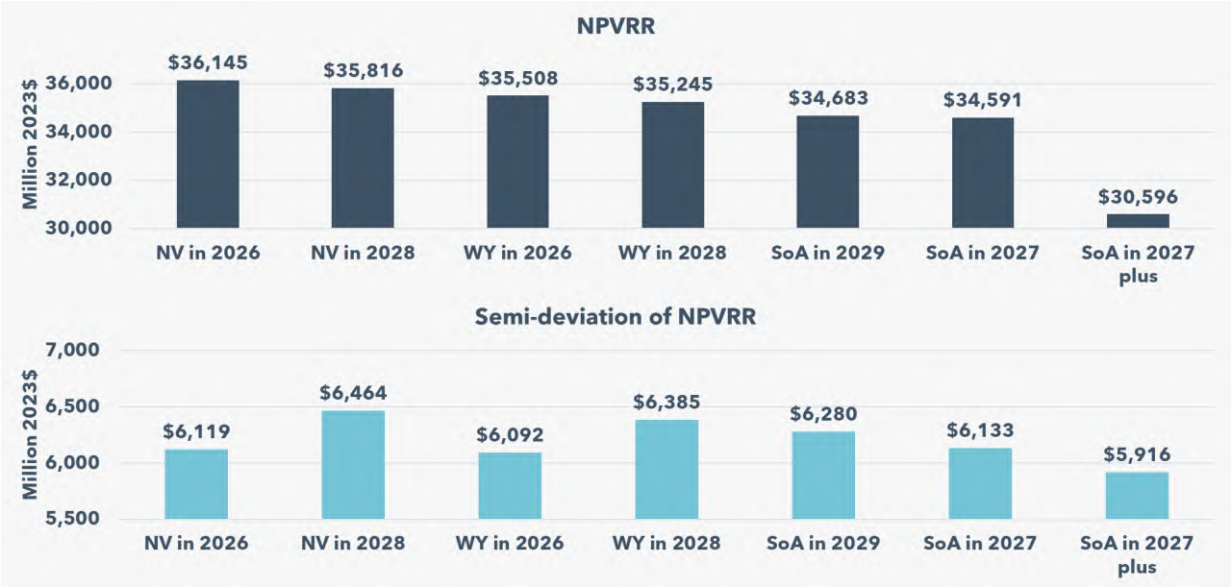
The transmission timing portfolios vary the timing of availability of transmission options to compare the transmission options against one another and to compare the impact of timing on the individual options. In 'SoA in 2027', 'SoA in 2029', 'WY in 2026', 'NV in 2026', 'WY in 2028' and 'NV in 2028', the model is required to add 400 MW of the corresponding transmission option in the noted year. In one additional portfolio ('SoA in 2027 plus'), the model is forced to add 400 MW of SoA in 2027 and has 400 MW each of WY and NV transmission options available for selection (but not required) beginning in 2026. The resource buildouts of the transmission timing portfolios are shown in **Figure 88**.

Comparing the cost and risk metrics of these actionable portfolios (**Figure 89**) shows that 'SoA in 2027' and 'SoA in 2029' have lower costs than the WY and NV portfolios. Because of declining resource cost curves and discounting of future costs, 'SoA in 2029' has lower costs than 'SoA in 2027'. However, it has higher risks, in terms of quantified risk metrics (**Figure 89**) and the unquantified risks associated with waiting to procure the necessary resources to comply with HB 2021's 2030 emissions targets.

The lowest costs and risks are found in the 'SoA in 2027 plus' portfolio, demonstrating the benefits of having more transmission options available (**Figure 88**). Comparing these actionable portfolios, PGE finds that investing to increase access to transmission earlier will provide the best balance of system costs and risks. This further reaffirms that PGE should first pursue all available opportunities to increase access to PNW proxy resources, such as the upgrade to the Bethel-Round Butte transmission line. Additionally, studying new transmission options can reduce potential dependence on emerging technologies and reduce costs, as shown in **Figure 89**.

Figure 88. Resource buildout in transmission timing portfolios

Figure 89. Cost and risk metrics of transmission timing portfolios



11.4.3 Community-based renewable energy (CBRE) portfolios

Studying the relationship between costs, risk and community benefits resulting from the deployment of CBRE resources has been a central discussion of this IRP.[306] PGE developed

[306] See **Sections 7.1 (CBRE), 7.1.3 (rCBI), 7.1.4 (pCBI)** and **7.1.6 (iCBI).**

the portfolios listed in **Table 58** to explore this relationship. The CBRE portfolios vary the quantity of CBREs and whether they are forced-in or are available for optimized selection in the model. Aside from the variations in CBRE availability, portfolios in this section assume a consistent set of assumptions to ensure comparisons provide insight on the impact of CBRE resources on portfolio outcomes.

Table 58. List of CBRE portfolios

Portfolios	Portfolio Condition
Default CBRE	100% of CBRE achievable potential is selected
CBRE: 75%	75% of CBRE achievable potential is selected
CBRE: Unavailable (informational)	CBRE resources are unavailable
CBRE: Microgrids	Only Microgrid CBRE resources are available
CBRE Optimize	CBRE resources compete economically

11.4.3.1 Results and insights

Results from these portfolios indicate that increasing the amount of CBRE resources decreases portfolio costs and risk (**Figure 90**). Additionally, the 'CBRE Optimize' portfolio selects the full amount of available CBRE resources and, alongside 'Default CBRE', which forces in the full amount of CBRE resources, has the lowest cost and risk. Portfolios community benefits indicators (CBIs), which are a function of the nameplate capacity of CBREs added in each portfolio and represent the level of community benefits provided (described in **Section 7.1.4, Portfolio community benefits indicators**), are shown in (**Table 59**). These results show that in addition to having the lowest cost and risk, the 'CBRE Optimize' and 'Default CBRE' portfolios provide the greatest community benefits.

This finding suggests that in a transmission-constrained system, CBRE resources can decrease cost and increase community benefits. These results drive the conclusion that PGE should include all 155 MW of available CBRE in the Preferred Portfolio. Additionally, it supports the conclusion that community benefits and cost minimization are not mutually exclusive. However, given both the magnitude of long-term transmission needs and the total forecasted technical potential for incremental CBRE additions, CBRE resources cannot be seen as a panacea for the challenges PGE faces with transmission availability.

Figure 90. Cost and risk metrics of CBRE portfolios

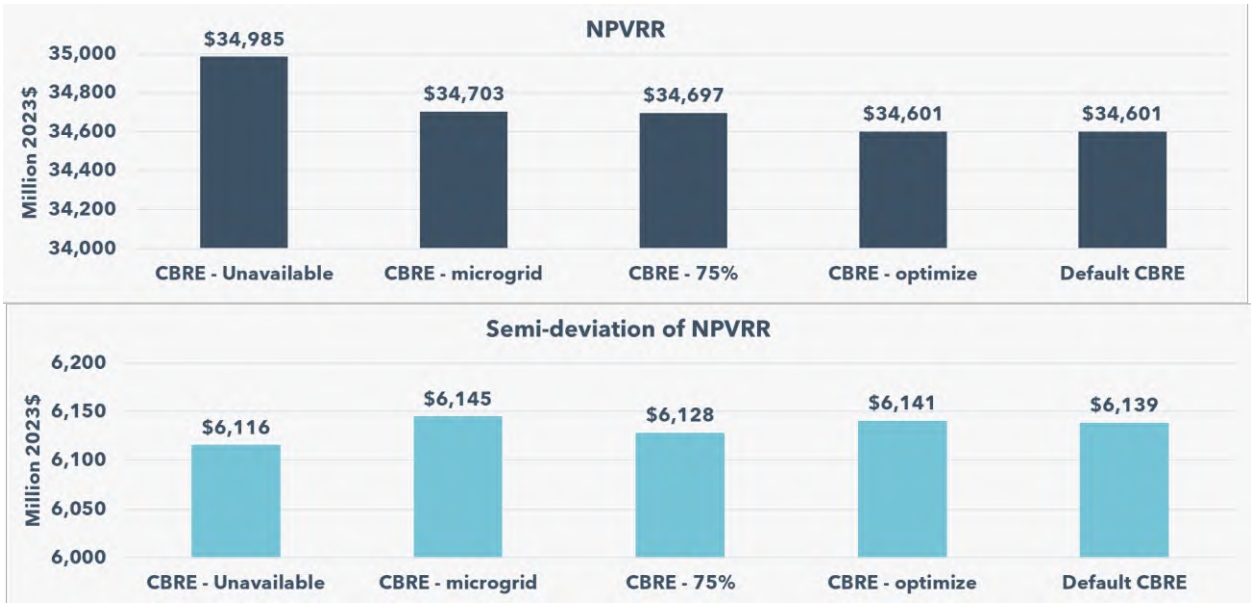


Table 59. Portfolio Community Benefit Indicator of each CBRE portfolio

Portfolios	Portfolio Community Benefit Indicator (pCBI)
Default CBRE	155
CBRE: 75%	116
CBRE: Unavailable	0
CBRE: Microgrids	100
CBRE Optimize	155

11.4.4 Energy efficiency and demand response portfolios

Through the DSP, PGE has committed to expanding the demand response (DR) portfolio to 211 MW of summer and 158 MW of winter demand response by 2028. Additionally, through the Energy Trust of Oregon (ETO) PGE estimates approximately 150 MWa of incremental cost-effective energy efficiency (EE) to be achieved by 2028. These resources are included as

a reduction in resource needs, namely capacity and energy (for more detail, see **Section 6.2, Distributed Energy Resource (DER) impact on load**).[307]

In this IRP, we also have estimated the costs and benefits associated with additional quantities of EE and DR (these estimates are described in both **Chapter 8, Resource options**, and **Chapter 10, Resource economics**). **Table 60** lists the portfolios PGE developed to understand whether these additional quantities of EE and DR could provide system benefits at lower cost and risk relative to other supply-side options. All portfolios in this section assume a linear reduction in emissions and the full 155 MW buildout of CBRE resources to ensure comparisons focus on the role of EE and DR. Additional EE and DR resources are available for selection in the years 2026 through 2030.

Table 60. List of EE and DR portfolios

Portfolios	Portfolio condition through 2030
Optimized Non-Cost-Effective (NCE) DERs	Allow model to select from total potential of additional EE and DR
Zero NCE	No additional EE and DR available (ETO and PGE cannot increase savings beyond current commitments)
25 MWa NCE EE	25 MWa of additional EE (5 MWa annually)
50 MWa NCE EE	50 MWa of additional EE (10 MWa annually)
60 MWa NCE EE	60 MWa of additional EE (12 MWa annually)
70 MWa NCE EE	70 MWa of additional EE (14 MWa annually)

The quantity of additional EE and DR added in these portfolios is shown in **Figure 91**. In the 'Optimized Non-cost-effective (NCE) DERs' portfolio, the model selected 53 MWa of the 70 total MWa of EE available. Additional DR was not selected in any of the portfolios as it has higher costs than any other available resources when it is available for selection (2026-2030), highlighting the need for program redesigns that reduce costs. When comparing the scoring metrics in **Figure 92**, increasing the amount of additional EE available for selection decreases portfolio cost and reduces risk up to a point. This shows that there are energy efficiency options that are more expensive than transmission options and the generic resource. Portfolio NPVRR decreases as the model is allowed access to increasing amounts of EE, from the highest costs for the 'Zero NCE' portfolio to the lowest cost for the '50 MWa EE' portfolio. The implications of these results are further discussed in the following section.

[307] These estimates from the DSP and ETO are based on the avoided costs of the 2019 IRP Update and thus do not account for reflect the economic tradeoffs within this IRP.

Figure 91. Resource buildout in energy efficiency and demand response portfolios

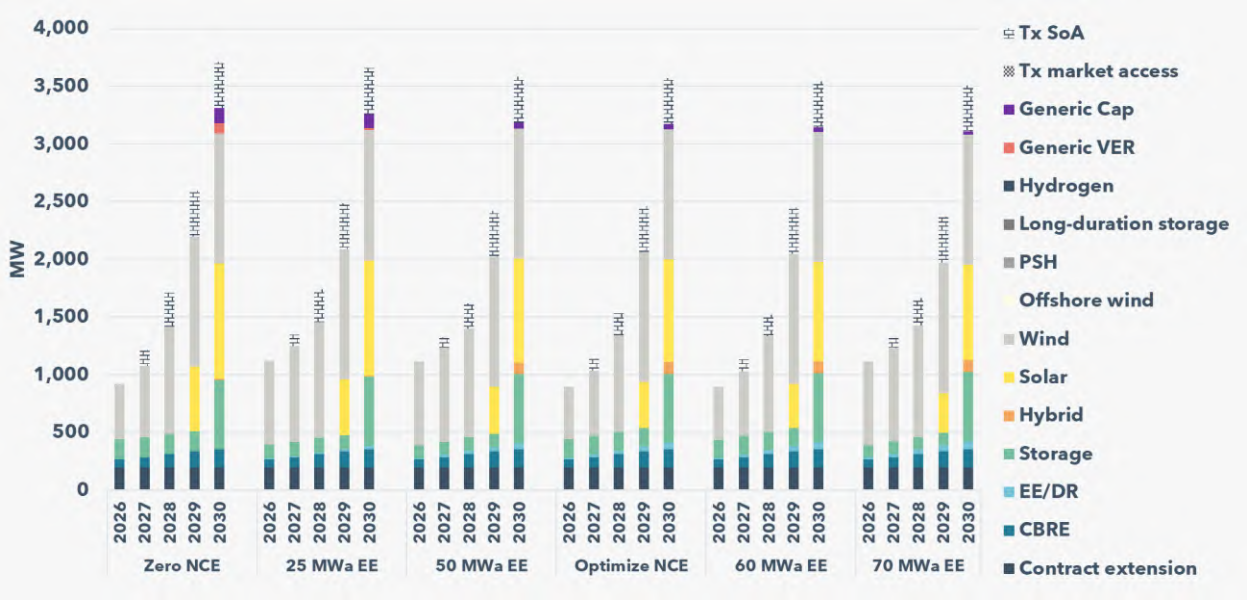
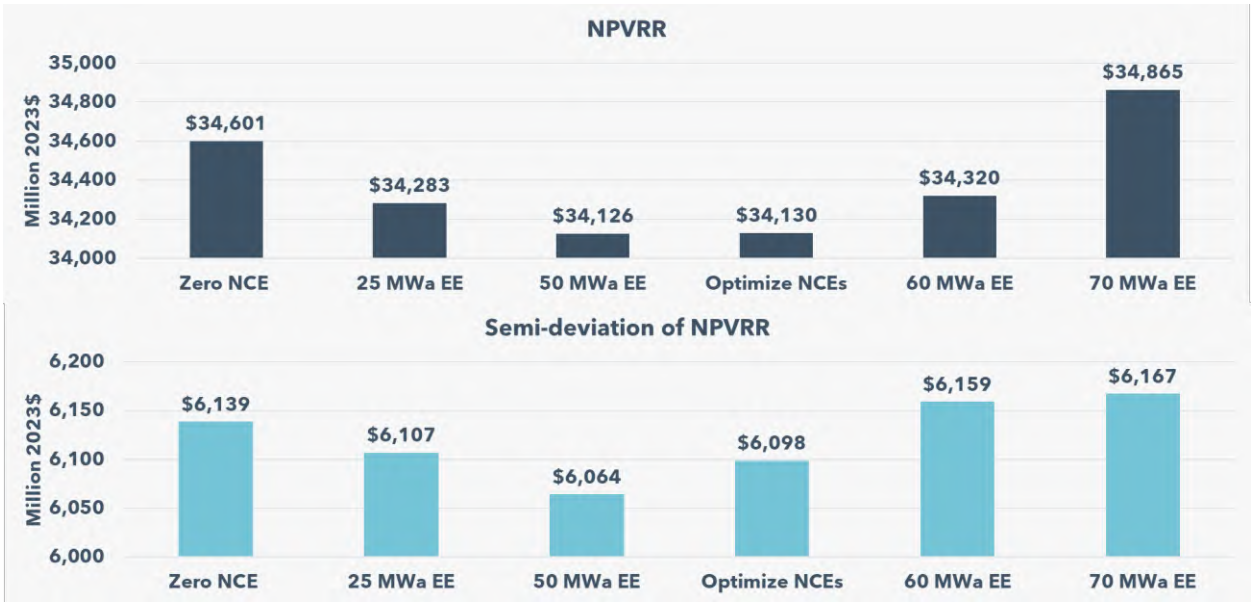


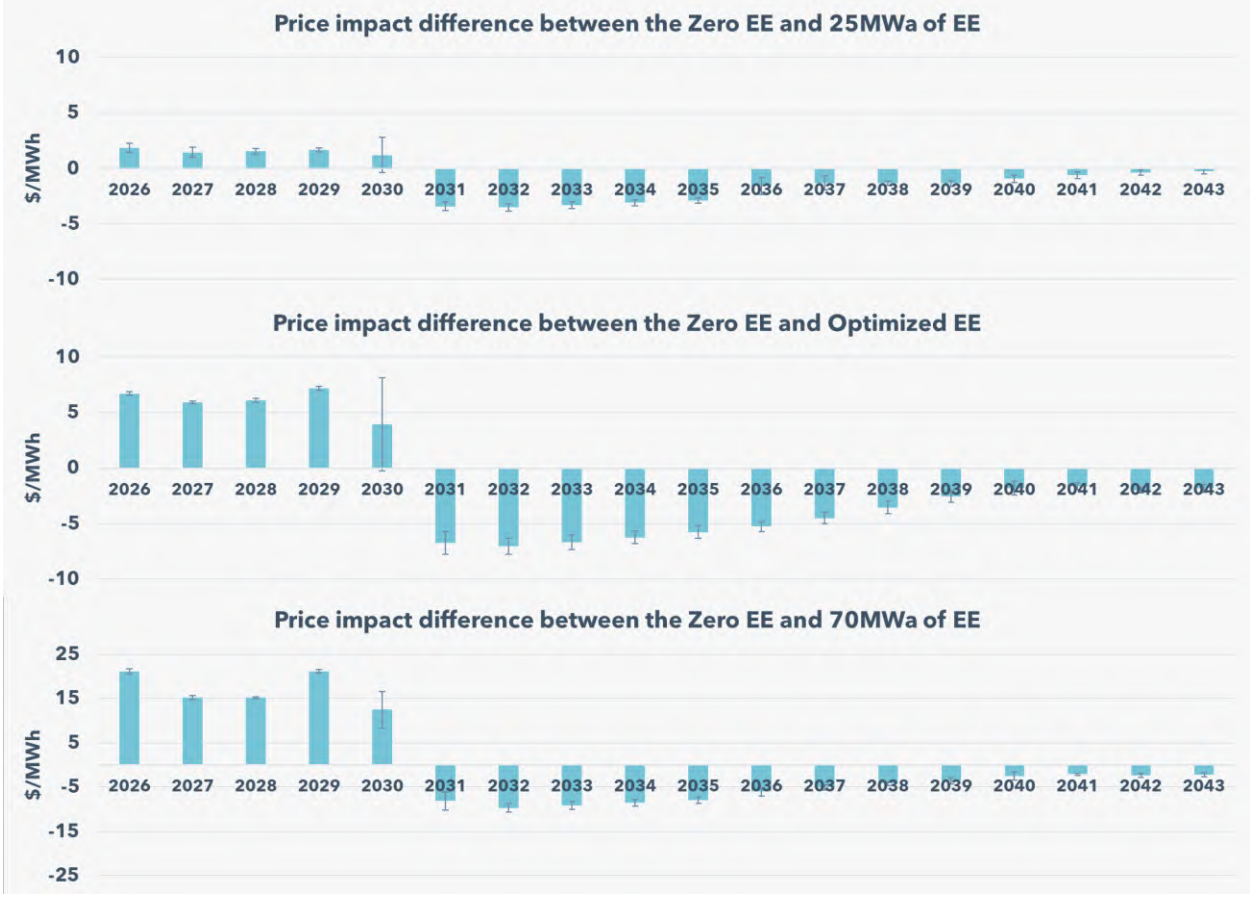
Figure 92. Cost and risk metrics of EE&DR portfolios



These results strongly identify the potential benefits of adding additional EE more than the quantities identified as 'cost-effective' using outputs from the 2019 IRP. This highlights a significant disconnect between resource planning using the current forecasts of costs and benefits in this IRP and resources that use previously calculated cost-effectiveness tests (such as energy efficiency and demand response). This disconnect is further described in **Section 10.7, Cost of clean energy**.

However, examination of the cost impacts of these portfolios identifies challenges related to the near-term cost impacts. **Figure 93** shows the difference in yearly price impact between the Zero EE portfolio and three portfolios with varying levels of additional EE (25MWa, Optimized and 70MWa). This figure underscores the relationship between acquiring increasing quantities of additional EE and the associated near-term price impacts. As additional EE is added the near-term price impact increases rapidly. Two unique policy factors drive these results. First, unlike other assets the additional EE is not financed or securitized, so the full cost is incurred before the generation starts. Second, EE decreases retail sales which leads to increased costs per unit of sales. Aggregated, these two effects lead to much higher near-term cost increases than the relevant comparators. Accordingly, EE under the current state policy creates large near-term price increases. When only considering long-term system cost this near-term effect is not apparent.

Figure 93. Yearly costs per MWh for additional EE portfolios through 2030



Despite ROSE-E suggesting the long-term benefits of adding additional quantities of EE, PGE has determined that the combination of near-term price impacts and the unquantified risk of

pursuing the resource outweighs the associated benefit. Accordingly, the Preferred Portfolio described in **Section 11.5, Preferred Portfolio**, does not contain any additional EE.

While the updated avoided costs produced by IRPs (as highlighted in **Section 10.7, Cost of clean energy**) could lead to higher quantities of EE being realized, additional policy changes that could more assuredly lead to procurement and/or securitize the procurement of EE will likely be needed for PGE to achieve the full cost and risk savings articulated in these portfolios. As the modeling suggests, energy efficiency is an increasingly important resource to PGE and the region's decarbonization strategies.

11.4.5 Optimized portfolios

With the Optimized portfolios group, PGE explored the impact of optimization choices on resource buildout, portfolio cost and risk metrics by varying the constraints imposed and the objective functions used to minimize costs. **Table 61** lists the portfolios PGE developed to test different objective functions. All portfolios in this section are built upon a linear reduction in emissions.

The 'Min Avg LT cost' and 'Optimized' portfolios use the default objective function to minimize the average NPVRR across all combinations of price, need and technology cost futures for the full portfolio analysis time horizon (2024-2043). The 'Min Avg ST cost' and 'Min Ref ST cost' portfolios use different objective functions than the rest of the portfolios. 'Min Avg ST cost' minimizes the average of NPVRR outcomes across all combinations of need, price and technology cost futures through the year 2030. 'Min Ref ST cost' minimizes the NPVRR of the Reference Case only and only through the year 2030.

The 'Min Avg LT cost', 'Min Avg ST cost' and 'Min Ref ST cost' portfolios have the default settings used across most portfolios of adding all 155 MW of CBRE resources and access to 400 MW of SoA in 2027. The 'Optimized' portfolio allows the model access to the least-restricted set of resource actions PGE can take.[308] In the 'Optimized' portfolio, the model has access to 400 MW of SoA in 2027, 400 MW each of WY and NV transmission in 2026, the full 70 MWa of additional EE, and has the option of selecting up to 155 MW of CBRE resources.

[308] Some informational portfolios, like the 'No Tx constraints' portfolio' do contain fewer restrictions but are not actionable.

Table 61. List of optimized portfolios

Portfolios	Portfolio condition
Min Avg LT cost	Minimizing average long-term (LT) NPVRR
Min Avg ST cost (informational)	Minimizing average short-term (ST) NPVRR through 2030
Min Ref ST cost (informational)	Minimizing Reference Case short-term NPVRR through 2030
Optimized (informational)	Least constrained

The 'Optimized' portfolio uses the access to additional EE, selecting 53 MWa by 2030 and adding less storage and renewables compared to the 'Min Avg LT cost'. As a result of the additional resources available for selection, 'Optimized' achieves lower costs and risk than 'Min Avg LT cost' (**Figure 94**). Additionally, the portfolio selects the full quantity of available CBRE resources, supporting the robustness of the findings in **Section 11.4.3, Community-based renewable energy (CBRE) portfolios**. And finally, the portfolio selects the SoA option, reinforcing the finding that the full quantity of resources available with existing transmission capacity (described in **Appendix H.7, BPA transmission in ROSE-E**) is insufficient to meet system needs at the lowest cost without also some expansion of transmission access.

Because they are optimized over a shorter timeframe of seven years compared to the standard 20 years for other portfolios, the cost and risk metrics of the 'Min Avg ST cost' and 'Min Ref ST cost' portfolios are not comparable to those of other portfolios for two reasons. First, only seven years of values are accounted for in their cost and risk metrics, so NPVRR outcomes are much smaller, and associated variability is lower. Second, beyond 2030, while the resource additions must still satisfy the constraints imposed on the model, they are not subject to the minimization of costs, and the model does not attempt to create an optimal resource buildout. The 'Min Avg ST cost' and 'Min Ref ST cost' portfolios produce nearly identical resource buildouts to one another and very similar resource buildouts (through 2030) to the 'Min Avg LT cost' portfolio (**Figure 94**).

Figure 94. Resource buildout in optimized portfolios

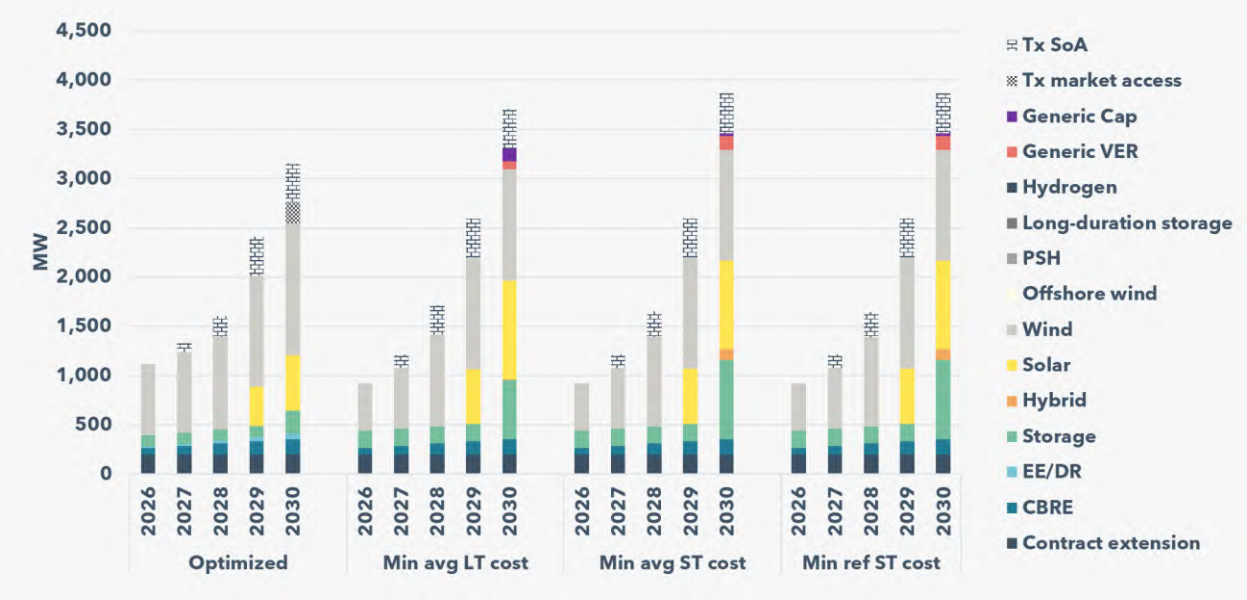
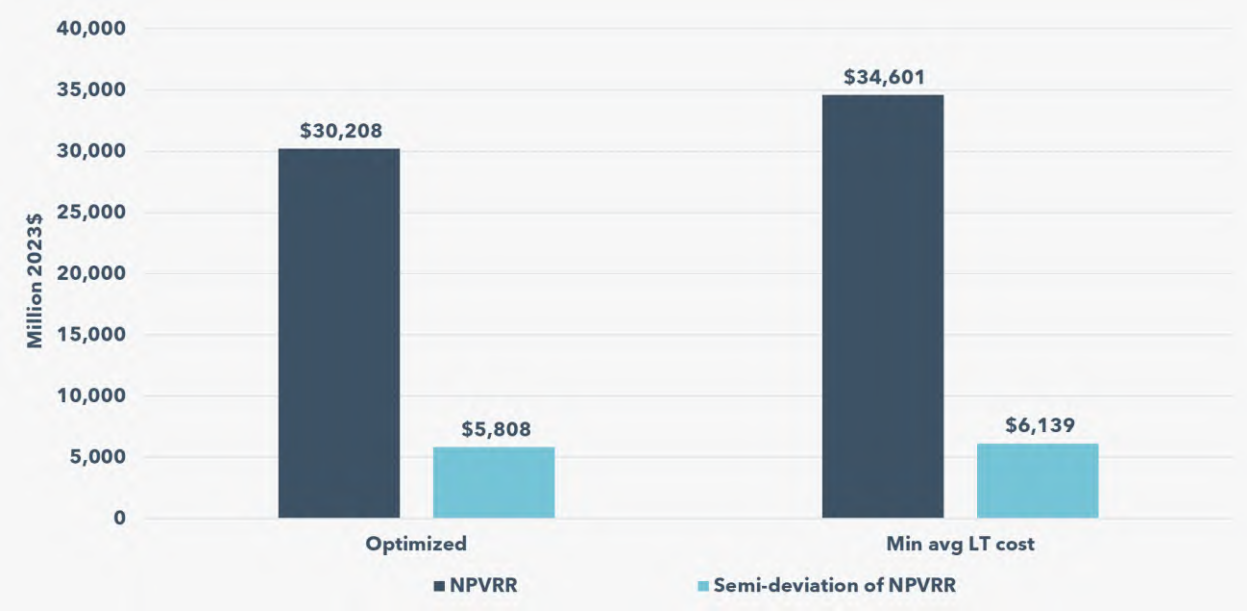


Figure 95. Cost and risk metrics of 'Optimized' and 'Min Avg LT cost' portfolios



11.4.6 Targeted policy portfolios

To inform stakeholder discussions, PGE developed targeted portfolios to study specific policy conditions, listed in **Table 62**. Both 'Targeted Policy' portfolios have a linear GHG-emissions reduction glidepath, have access to 400 MW of SoA upgrade in 2027, and must add all 155 MW of CBRE resources. Neither portfolio has access to WY or NV transmission expansion options.

Table 62. List of targeted policy portfolios

Portfolios	Portfolio condition
Physical RPS	Enforce physical renewable portfolio standard (RPS) compliance
Oregon-only Resources	Limit resource availability to Oregon-sited only

The 'Oregon-only resources' portfolio does not allow the model to select resources sited outside of Oregon (i.e., SE Washington, Wyoming, Montana Wind or NV Solar). Because the portfolio has less access to improved effective load carrying capacities (ELCC) of out-of-state resources and a lower total availability of non-generic resources, a larger quantity of resource additions and increased reliance on generic resources are required to meet energy and capacity needs compared to portfolios that have access to out-of-state resources. The impact on resource buildout is demonstrated in **Figure 96** through comparison with the 'SoA in 2027 plus' portfolio from the transmission timing portfolios, which allows the model to access all out-of-state resources. The increase in quantity of resource additions and reliance on generic resources creates higher portfolio costs and **Figure 97** shows that the NPVRR of the 'Oregon-only resources' portfolio is $4.213 billion higher than the 'SoA in 2027 plus' portfolio. These results suggest that limiting the geographic area available to develop generation resources could lead to increased cost and risk for PGE's customers.

The 'Physical RPS' portfolio requires a resource buildout that ensures physical RPS requirements, meaning REC generation from existing and new resources must meet or exceed RPS obligations in all years. Because the need to add renewable resources to meet the requirements of HB 2021 is greater than is required for RPS compliance, the physical RPS requirement does not impact resource buildout or portfolio cost.

Figure 96. Resource buildout in Oregon-only resources and SoA in 2027 plus portfolios

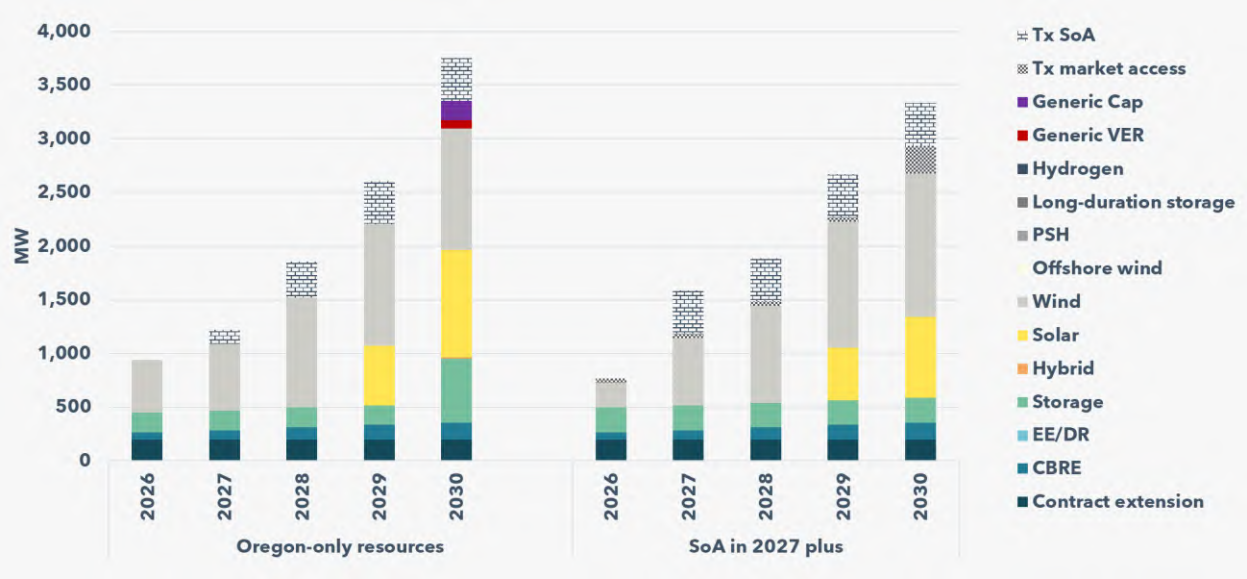
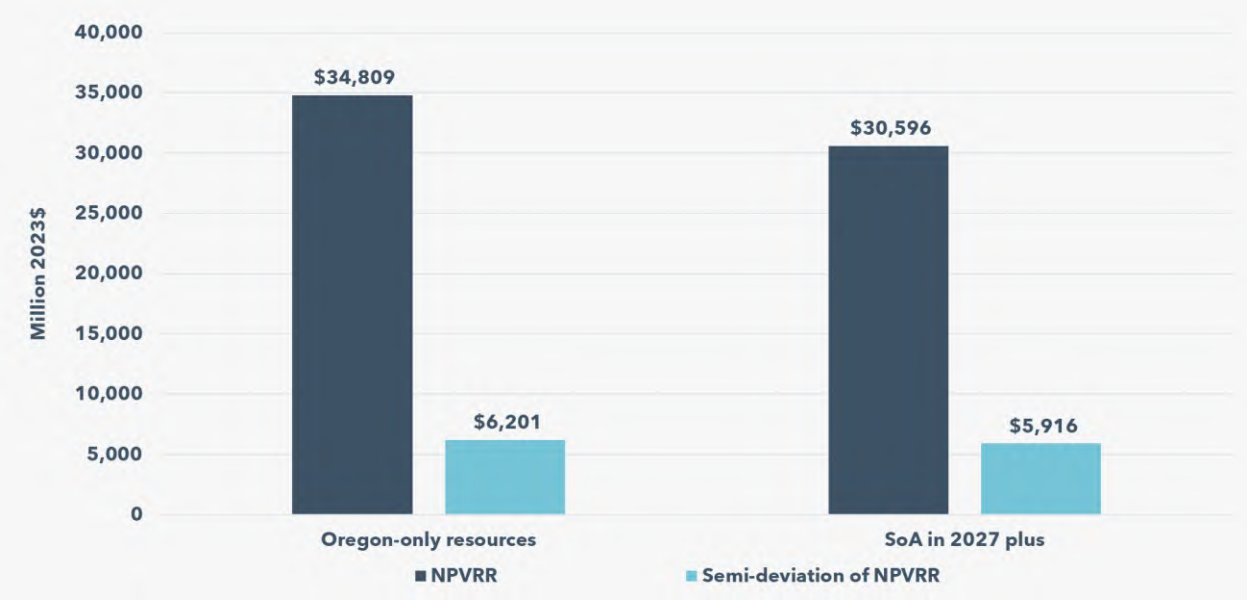


Figure 97. Cost and risk metrics of Oregon-only resources and SoA in 2027 plus portfolios



11.4.7 Emerging technology portfolios

Emerging technologies can potentially reduce portfolio costs and minimize the need for transmission expansion. To understand the potential impact of emerging technologies on transmission, cost and risk, PGE has explored portfolios listed in **Table 63**. The potential for emerging technologies to help PGE meet HB 2021 targets is explored in **Section 8.5, Post-**

2030 resource options, and the implications of the speed of development of and cost declines of emerging technologies are further explored here.

Table 63. List of emerging technology portfolios

Portfolios	Portfolio condition
Pumped hydro	333 MW of pumped storage hydro (PSH) in 2028
Hydrogen blending	Blending of hydrogen at existing natural gas (NG) plants
Hydrogen building	100 MW of hydrogen in 2029
Offshore wind (Informational)	500 MW of offshore wind in 2032
Long Duration Storage (Informational)	139 MW of 24 hr. battery in 2028
RTO (Informational)	200 MW Reduction in Capacity Need

In the 'Pumped hydro' portfolio, 333 MW of 10-hour pumped hydro storage (PSH) is added in 2028.[309] The 'Long Duration Storage (LDS)' portfolio includes 139 MW of 24-hour battery in 2028.[310] The 'Hydrogen blending' portfolio models the conversion of existing PGE-owned NG plants to run on a partial hydrogen fuel blend.[311] The hydrogen-derived non-emitting power provides energy but does not provide additional capacity because the hydrogen is blended into existing power plants. The 'Hydrogen building' portfolio adds 100 MW of new 100 percent hydrogen-fueled dispatchable capacity, providing both energy and capacity. The 'Offshore wind' portfolio adds 500 MW of offshore wind in 2032.[312,313] The 'Regional transmission organization (RTO)' portfolio considers the potential benefits that PGE might

[309] This represents 1/6th of the 2000 MW of known potential projects in the region (Swan Lake 400 MW, Gordon Butte 400 MW and Goldendale 800 MW). A 1/6th portion of the total capacity is representative of the fact that PGE is one of six regional IOU's.
[310] 139 MW of 24-hr storage provides the same amount of energy storage as 333 MW of 10-hour storage.
[311] Hydrogen is blended into PGE's CCCT natural gas plants starting in year 2029. For modeling purposes, the energy generated by hydrogen is additional to the energy generated by burning natural gas and fully serves retail load.
[312] This represents 1/6th of the 3000 MW of potential capacity along the Oregon Coast identified by the Bureau of Ocean Energy Management (BOEM) available at: 2022-Floating-Offshore-Wind-Report.pdf (oregon.gov).
[313] The 2032 expected COD for offshore wind is aligned with findings of the Northwest Power and Conversation Council, available at: https://www.nwcouncil.org/fs/17860/2022_08_p3.pdf.

realize from joining an RTO by reducing capacity need by 200 MW annually beginning in 2031.[314]

The addition of PSH, LDS and Hydrogen can be seen in the resource buildouts shown in **Figure 98**. Resource buildouts for the 'Offshore wind', 'Hydrogen blending' and 'RTO' portfolios are shown in **Figure 99**. The offshore wind addition can be seen in 2032, while for the 'RTO' and 'Hydrogen blending' portfolios, the impact on resource buildout takes the form of a reduced need for resource additions. The resource buildout of the 'Offshore wind' portfolio differs substantially from the other Emerging Technology portfolios beginning in 2032 when offshore wind is added. Because of the high-capacity factor of offshore wind and the resulting large amount of energy added to the portfolio, the model is able to add a large amount of storage to complement the offshore wind addition, reducing reliance on the generic VER resource relative to other Emerging Technology portfolios, which are more reliant on the energy provided by generic VER. As a result of the 'Offshore wind' portfolio's lower reliance on the expensive generic resource, it has the lowest cost outcomes in the group (**Figure 100**).

Some impacts of emerging technologies on the pre-2030 resource buildout can be seen. While all portfolios add the same amount of wind (1128 MW), the 'Hydrogen blending' portfolio adds less solar (668 MW) than the other portfolio (between 1000 MW and 1010 MW). This smaller addition of renewables in "Hydrogen blending' is because of the additional existing energy available associated with hydrogen blending starting in 2029. Additionally, the 'Pumped hydro' and 'Long Duration Storage' portfolios both reduce the addition of other storage options through 2030. The relatively minor impacts on resource builds across the Emerging Technology portfolios highlights that resource actions now are not likely to be majorly impacted by emerging technologies (a finding that is explored further in **Section 11.5.3, Resource buildout robustness analysis**).

However, emerging technologies have a larger impact on longer-term actions, decreasing dependence on transmission expansion and the expensive generic resources. Given the high cost of the generic resources, the larger the addition of an emerging resource, the more costs can be reduced (as shown in **Figure 100** by the relatively low costs of the 'Offshore wind' portfolio, which has the largest addition of emerging technology). Unquantified benefits of these emerging technologies could include reduced dependence on the timing of transmissions projects. Thus, continued investigation of emerging technologies is warranted and can be a strategy for reducing costs in the longer term.

[314] A 200 MW reduction in capacity need represents 5 percent of PGE's peak load of approximately 4,000 MW. This was used to define the potential benefits of joining an RTO based on SPP's estimate that load diversity reduces their need for capacity by approximately 5 percent of their peak load, described here: 2021 spp mvs methodology.pdf.

Figure 98. Resource buildout in long duration storage, pumped hydro and hydrogen building portfolios

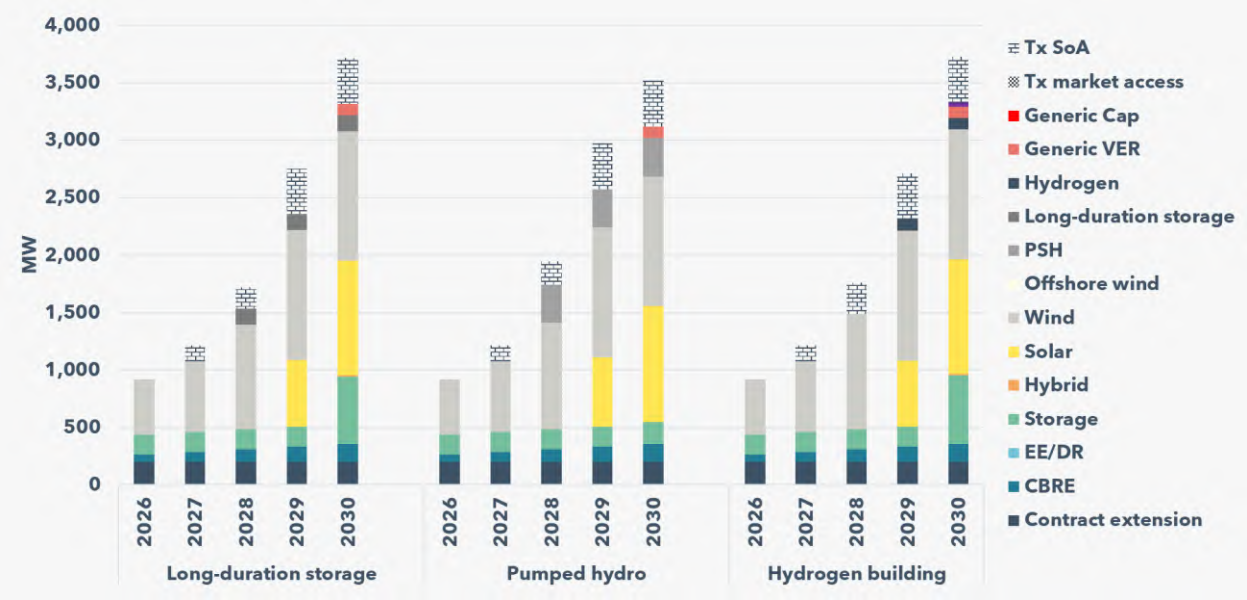


Figure 99. Resource buildout in RTO, hydrogen blending and offshore wind portfolios

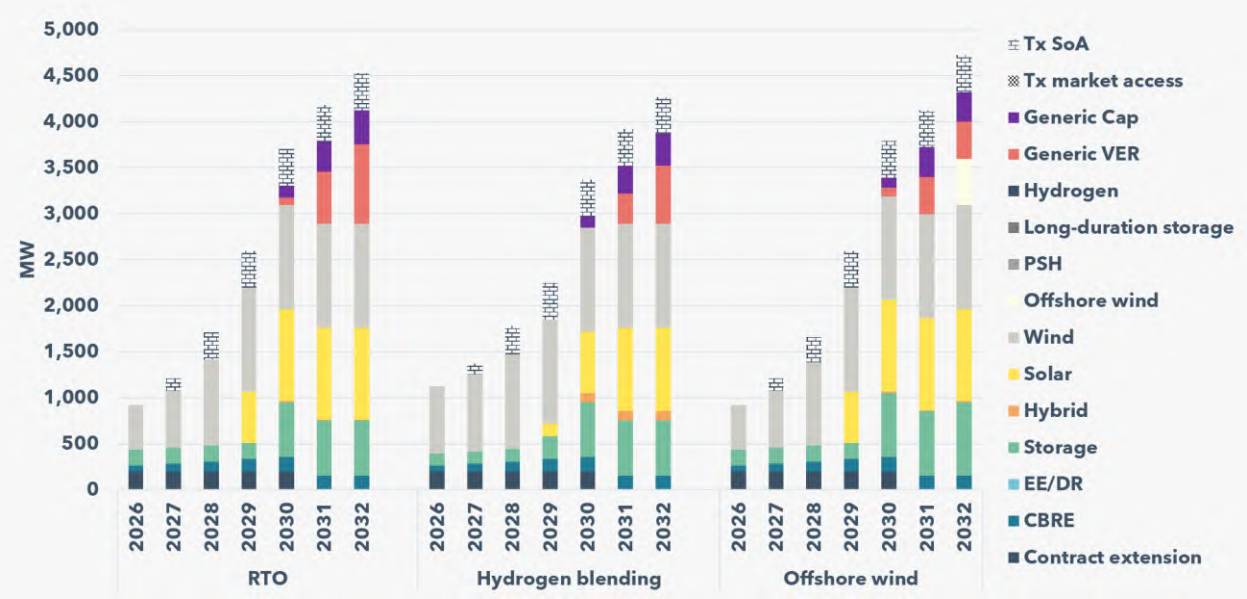
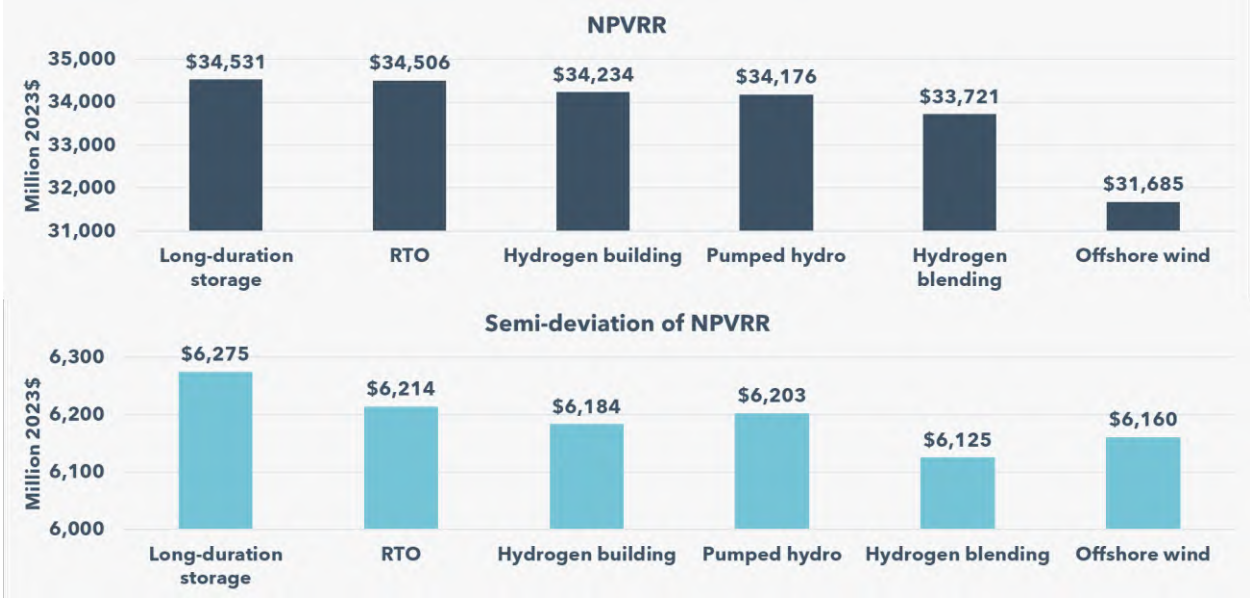


Figure 100. Cost and risk metrics of emerging technology portfolios



11.5 Preferred Portfolio

PGE evaluated 39 portfolios to answer key questions in PGE's current energy economic landscape. Based on these insights, PGE developed a Preferred Portfolio to meet system needs based on the answers to key questions and common themes. The Preferred Portfolio meets HB 2021 emissions reductions targets using the linear decarbonization glidepath and is forecast to emit 32.67 MMTCO2e over the entirety of the 2024-2043 portfolio analysis time-horizon (as shown for the 'Linear decline' portfolio in **Section 11.4.1, Decarbonization glidepath portfolios, Figure 78**). The Preferred Portfolio also complies with RPS obligations, as demonstrated in **Section 11.5.2, Resulting RPS position.** The key findings that emerged from portfolio analysis and were used to define the Preferred Portfolio are presented in **Figure 101**.

Figure 101. Key findings from portfolio analysis used to define the Preferred Portfolio

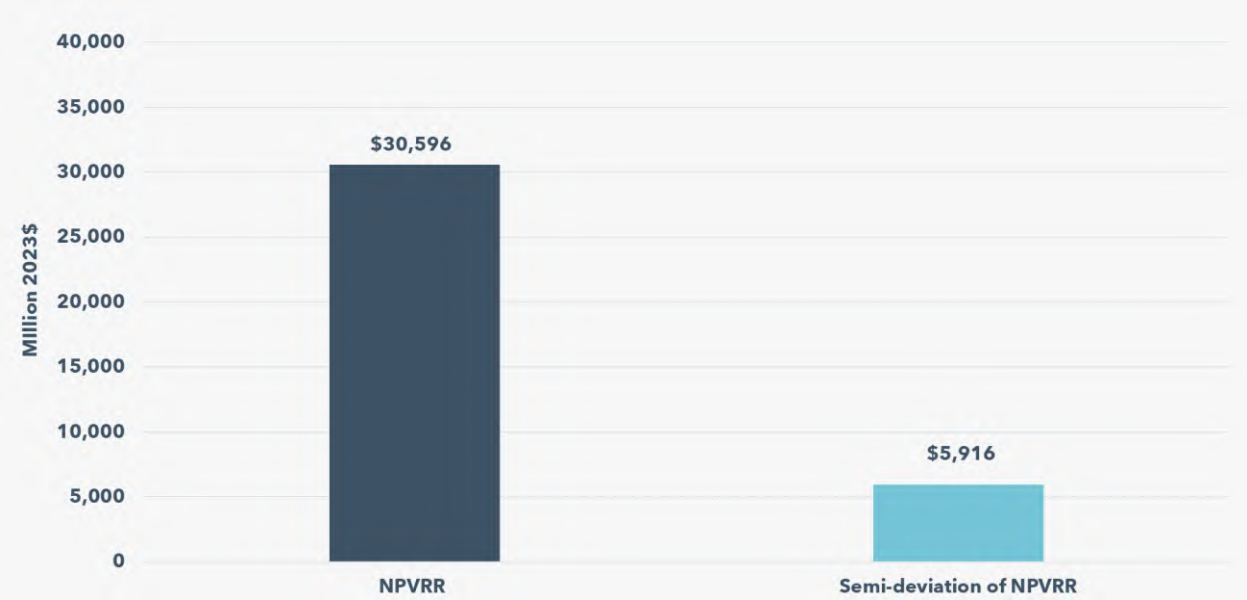
Through 2030, the Preferred Portfolio selected optimized quantities of VERs totaling 2,090 MW, 232 MW of storage and 255 MW of transmission expansion proxy resources. The 255 MW of proxy transmission resources have an associated 206 MW of WY wind and 49 MW of NV solar, which are included in the total VER quantity. No hybrid resources were selected, with the model instead utilizing existing transmission capacity to select stand-alone VER resources with higher capacity factors paired with stand-alone storage options and capacity-dense Tx expansion proxies. Additionally, the resource buildout of the Preferred Portfolio includes 200 MW of non-GHG-emitting contract extension, 400 MW of SoA Tx upgrade

added in 2027 and 155 cumulative MW of CBRE resources. The model was not allowed access to additional EE or DR in the Preferred Portfolio but does include a total of 156 MWa of cost-effective EE and 223 MW of cost-effective DRs, which are accounted for as a reduction in resource needs (see **Section 6.2, Distributed Energy Resource (DER) impact on load**). The Preferred Portfolio meets capacity and energy needs with the resource buildout, shown in **Table 64**, at a cost of $30,596 million (NPVRR in **Figure 102**).

Table 64. Cumulative resource buildout in Preferred Portfolio (MW)

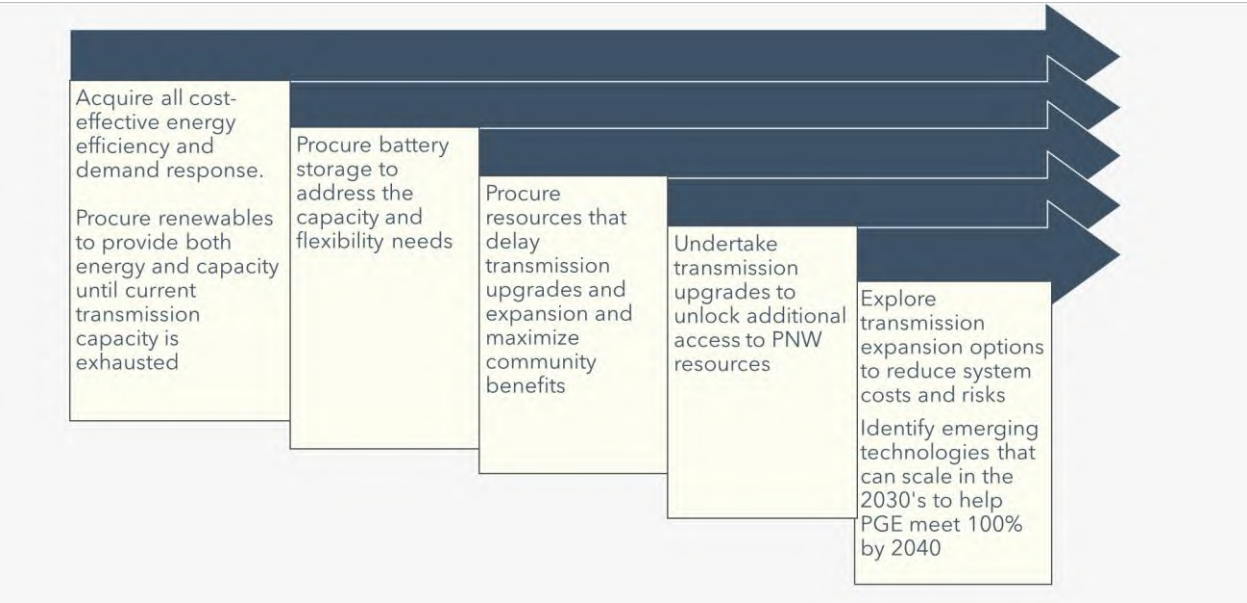
	2024	2025	2026	2027	2028	2029	2030
Wind	0	0	227	627	901	1172	1334
Solar	0	0	0	0	0	490	756
Hybrid	0	0	0	0	0	0	0
Storage	0	0	232	232	232	232	232
CBREs	0	0	65	84	110	133	155
WY Tx	0	0	44	44	44	44	206
NV Tx	0	0	0	0	0	0	49
SoA Tx	0	0	0	400	400	400	400
Additional EE & DERs	0	0	0	0	0	0	0
Non-GHG-Emitting Contract Extension	0	0	200	200	200	200	200
Cost-effective EE (MWa)	30	60	90	120	150	183	216
Cost-effective DR	133	162	183	199	211	218	228
Clearwater Wind	311	311	311	311	311	311	311
Wasco solar (RFP Proxy)	0	230	230	230	230	230	230
Christmas Valley solar (RFP Proxy)	0	180	180	180	180	180	180
4 hr battery (RFP Proxy)	0	400	400	400	400	400	400

Figure 102. Cost and risk metrics of the Preferred Portfolio



When considered in aggregate, these insights highlight how the binding nature of decarbonization and transmission constraints severely limit the options available to PGE and necessitate an approach to pursue all avenues of resource additions that are available and feasible. **Figure 103** visualizes the summary of these insights.

Figure 103. Visualizing the key themes of portfolio analysis that necessitate a 'pursue all' approach to best balance cost, risk, emission reduction and community benefits



11.5.1 Preferred Portfolio yearly price impacts[315]

Although the yearly price impacts do not represent actual customer price impacts, the near-term price impacts are an important concern when evaluating options to decarbonize reliably. Through an extensive analysis of resource additions amongst a variety of portfolios, we have found that while the incremental resource additions included in these estimates represent the least cost and risk manner to meet the emissions targets established in HB 2021, they are anticipated to raise the costs associated with generation resources relative to a 2023 baseline. These Reference Case price changes, normalized by load, are shown in **Figure 104**. In the very near-term, the price impact of the 2021 all-source RFP resources coming online in 2025 can be offset in part by expected increased wholesales sales based on economic dispatch and market prices. The compounded annual growth rates (CAGR) of those price impacts 2024-2030 are displayed in **Table 65**. After 2025, the Preferred Portfolio adds the resources listed in **Table 64**. With a 50 percent ownership assumption, the ITC benefits of storage resources added in 2026 partially offset the impact of cost increases from resources added in the 2021 all-source RFP. Incremental resource additions, including the expansion of the existing transmission system, continue to increase the costs of generation resources through 2030. While this analysis does not represent actual changes to customer prices, it is suggestive that, on a planning basis, system costs are likely to increase through

[315] **Addendum: PGE CEP Data Template** contains the annual price impact in $'s and the annual price impact per unit retail sales ($/MWh) through the planning horizon for each portfolio

2030: the Reference Case costs of generation resources, normalized by load growth, are forecast to increase by approximately 21 percent by the end of the decade.

Given the constraints in the planning environment associated with HB 2021 decarbonization goals and transmission availability, the need for resource procurement identified in this IRP is large and appears to result in substantial impacts on costs. PGE constructed a Preferred Portfolio that minimizes the costs and risk of these new resource acquisitions and maximizes the provision of community benefits by thoroughly investigating key decision points with the potential to impact costs. This includes selecting a linear GHG-emissions reduction pathway that complies with HB 2021 requirements while mitigating costs relative to more-aggressive pathways and reducing risks compared to less-aggressive pathways. Choices that minimize cost or risk were also made regarding additional DERs, the inclusion of CBRE resources and opportunities to expand transmission availability. Mitigating the impact of this increase in costs will be critical and PGE will continue to study all potential options that can help minimize costs, including continuing to explore the potential of emerging technologies as they develop and studying options to expand transmission access.

Figure 104. Yearly price impact (in $/MWh) of the Preferred Portfolio

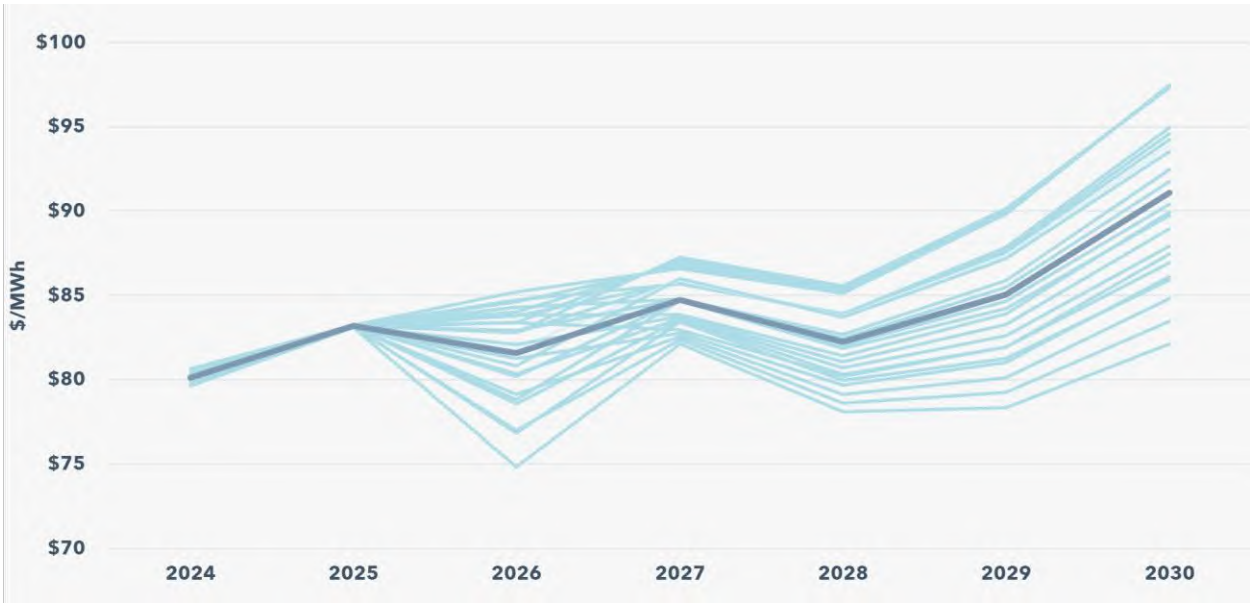


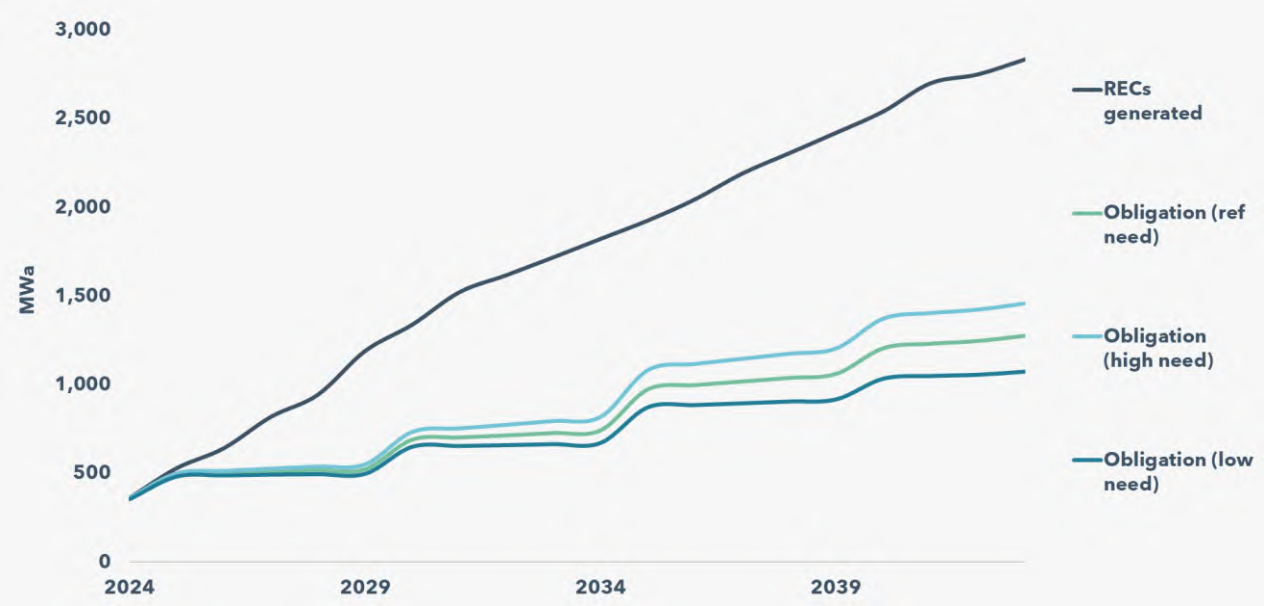
Table 65. Compounded annual growth rate of price impacts of the Preferred Portfolio 2024-2030

Tax Credit Levels	PGE Ownership				
	0%	25%	50%	75%	100%
50%	3.9%	3.9%	3.8%	3.8%	3.8%
75%	3.4%	3.3%	3.2%	3.2%	3.1%
100%	2.9%	2.8%	2.6%	2.4%	2.3%
125%	2.4%	2.2%	1.9%	1.7%	1.5%
150%	1.9%	1.6%	1.3%	0.9%	0.6%

11.5.2 Resulting RPS position

PGE's RPS requirements are described in **Section 6.7, RPS need**. **Figure 105** shows the number of 5-yr RECs forecast to be generated by adding new resources in the Preferred Portfolio and REC obligations for the low, reference and high Need Futures. The generation of RECs from the existing and incremental RPS resources in the Preferred Portfolio is forecasted to enable PGE to comply with RPS requirements. While HB 2021 regulations are not REC-based, the need to add new non-emitting resources to comply with HB 2021 GHG reduction requirements is larger than is needed to comply with RPS requirements, resulting in the forecast number of RECs generated by PGE's portfolio greatly exceeding RPS requirements.

Figure 105. RPS compliance of Preferred Portfolio[316]



11.5.3 Resource buildout robustness analysis

Portfolio analysis in the 2023 IRP is heavily focused on resource acquisition needs primarily in the Action Plan window of 2026-2028, and secondarily on the crucial years for achieving compliance with HB 2021 emissions reductions targets of 2029 and 2030. Uncertainty surrounding key forecasts and assumptions used in portfolio analysis increases over the planning horizon, making findings for the latter years of the analysis less robust than those for the near-term.

In addition to the increased uncertainty in forecasts of variables like market prices and costs of commercially available technologies like VERs and storage, substantial uncertainty exists about the economic and technological development rate of emerging non-GHG-emitting technologies. It is likely that rapid development in the availability and cost of one or more of these emerging technologies will be needed for PGE to achieve the HB 2021 100 percent reduction in GHG-emissions target by 2040. The potential roles of a variety of emerging technologies in helping PGE fully decarbonize by 2040 are explored in **Section 8.5, Post-2030 resource options**.

Because of the substantial resource needs PGE faces in the near-term, it is infeasible to wait for emerging technologies to develop before taking resource procurement actions: near-term needs must be met using currently available technologies. However, resource

[316] This forecast of 5-year REC generation includes RECs that have been designated for retirement voluntary programs

acquisition decisions made by PGE now should attempt to minimize the risk of negative impacts on the ability to use the range of emerging technologies as they develop in the future.

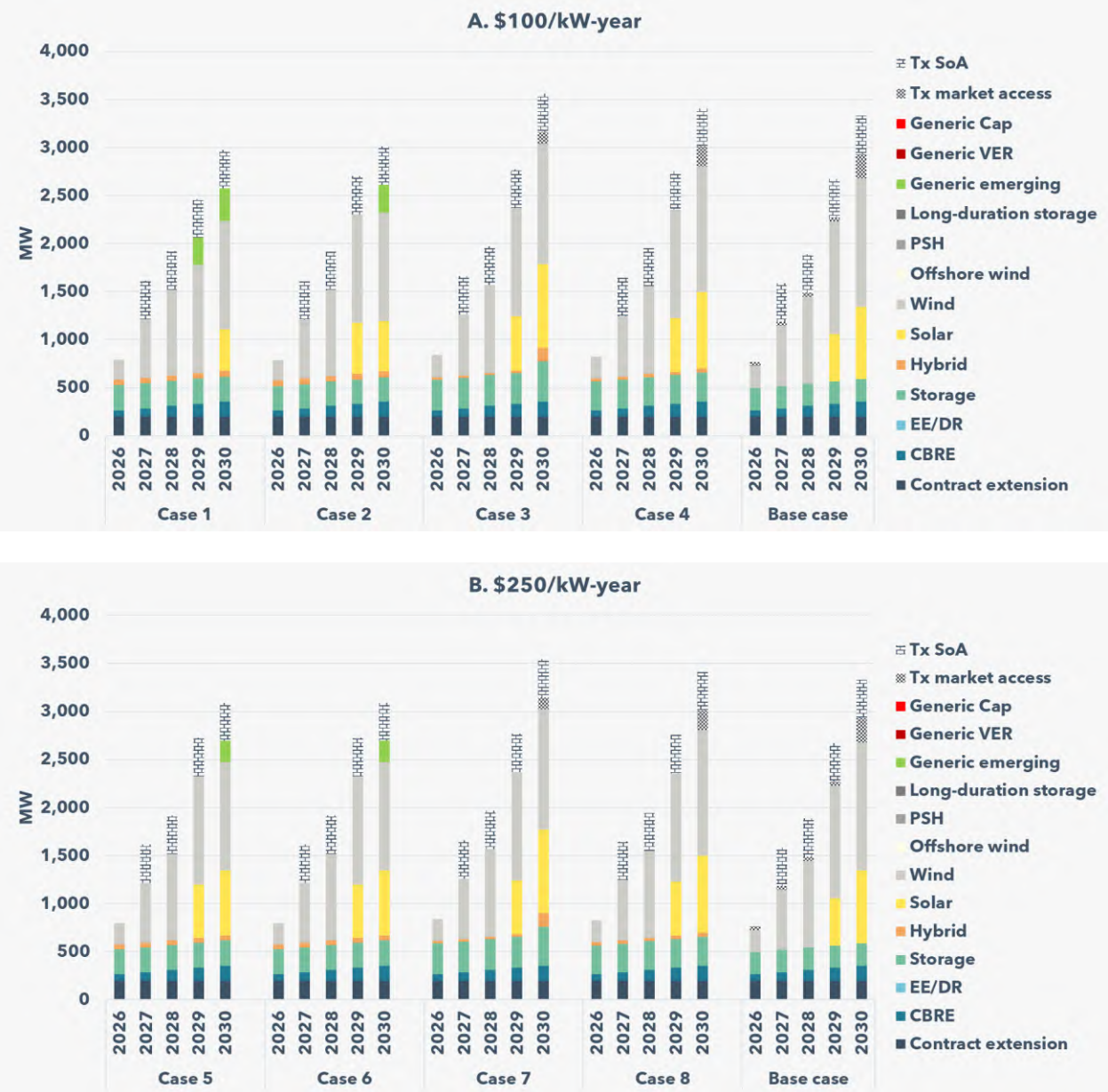
To test the robustness of the resource buildout in the near-term against these sources of uncertainty, PGE conducted an analysis varying the cost and timing of availability across multiple years and cost levels of an additional generic, non-emitting emerging resource with 100 percent ELCC and 50 percent capacity factor, representing a range of rates of development of emerging technologies. As shown in **Table 66**, 16 cases were analyzed with the first year of availability varying from the first-year post-Action Plan (2029) out to 2032 at a cost ranging from $100/kW-year to $1,000/kW-year. All cases have an otherwise consistent set of assumptions and are compared against a base case in which the generic emerging resource is defined in the default manner for portfolio analysis of being available for $1,000/kW-year after 2030.

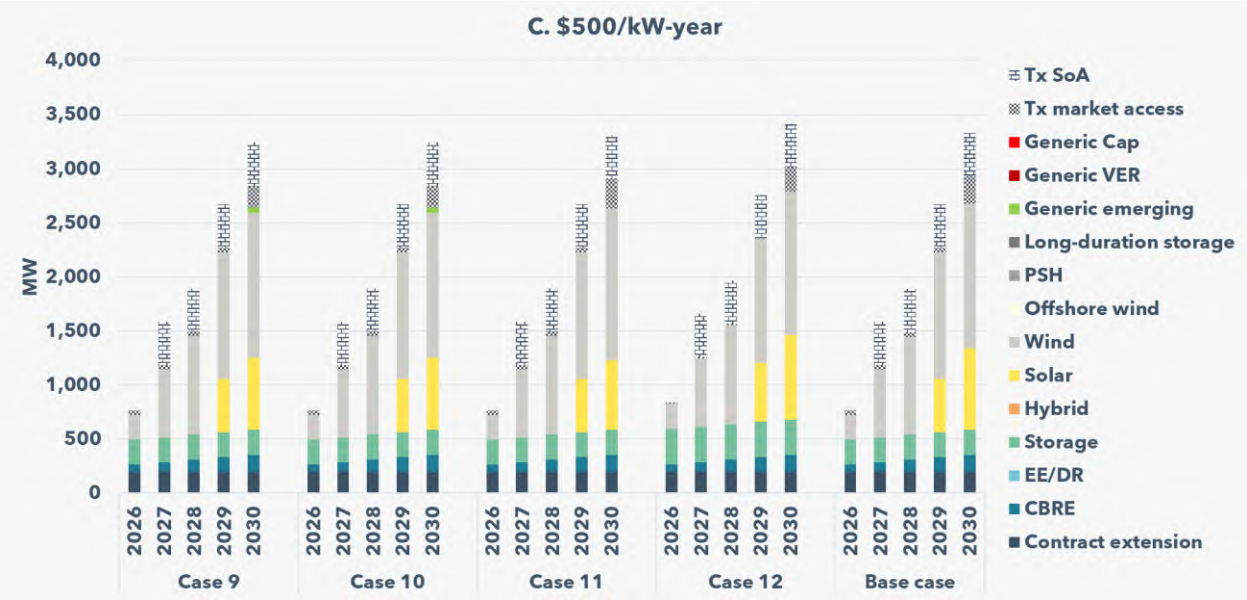
Table 66. Timing and cost of generic resource availability

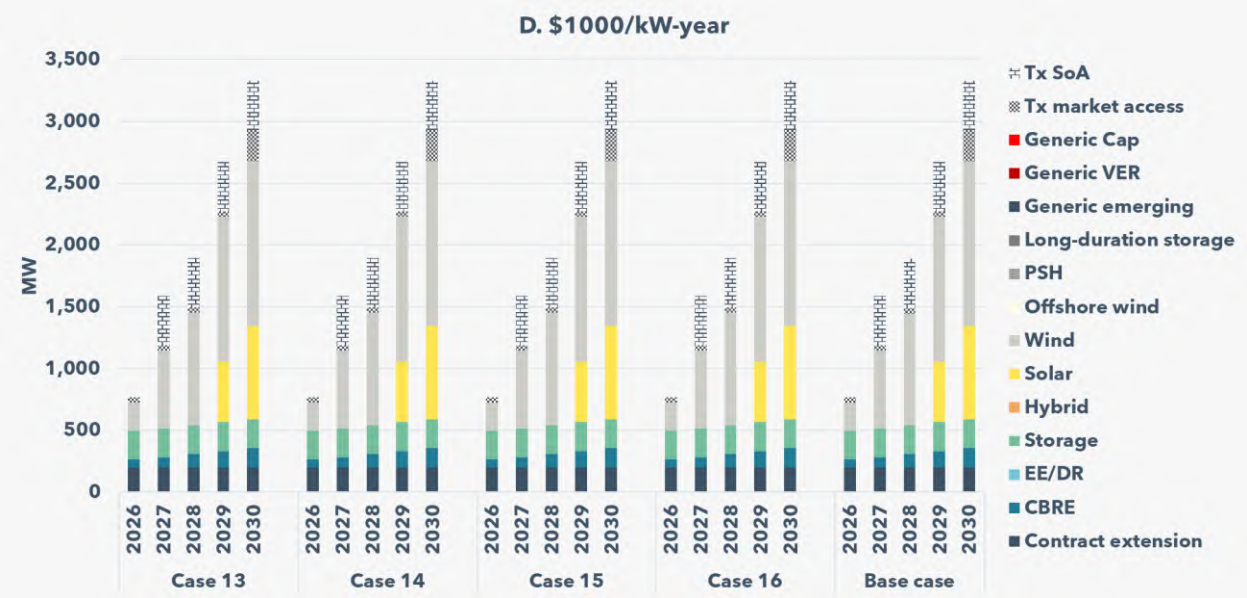
	Cost of generic resource			
Year	**$100/kW-year**	**$250/kW-year**	**$500/kW-year**	**$1000/kW-year**
2029	Case 1	Case 5	Case 9	Case 13
2030	Case 2	Case 6	Case 10	Case 14
2031	Case 3	Case 7	Case 11	Case 15
2032	Case 4	Case 8	Case 12	Case 16

The resulting resource additions are shown in **Figure 106.** When the generic emerging resource is available for $1,000/kW-year, the resource buildout of the Preferred Portfolio is almost entirely unaffected, regardless of the year it becomes available. When the generic emerging resource is available for $500/kW-year, it is selected as early as 2030, and some minor changes in resource buildout are seen across all four cases. Additions of the generic emerging resource in 2030 offset solar and transmission additions. At a cost of $250/kW-year, the generic emerging resource is selected as early as 2030 and is added in larger amounts than at a cost of $500/kW-year. When the generic emerging resource is available for $100/kW-year, it is selected in the first year it becomes available (as early as 2029). In both cases, the most notable impact on the Preferred Portfolio resource buildout is on the selection of WY and NV transmission expansion. When the generic emerging resource becomes available in 2029 or 2030, the model shifts entirely away from transmission expansion, while in the cases in which it becomes available in 2031 or 2032, transmission expansion is selected in 2030, but in smaller amounts than in the Preferred Portfolio.

Figure 106. Resource buildout of resource build robustness analysis scenarios, grouped by generic resource cost







The results of the analysis show that at prices at or above $1,000, the resource buildout of the Preferred Portfolio is unaffected and at prices at or above $500/kW-year the impacts are very slight, regardless of when the generic resource becomes available. Between $250 and $500, there is an inflection point above which the resource buildout of the Preferred Portfolio is robust to the impacts of future technological developments of emerging non-GHG emitting resource options. Transmission expansions are the most expensive proxy resources available for selection (aside from non-cost-effective DR) and are, therefore, likely to be the first

additions to be offset by development of emerging technologies. However, given the rapid cost declines and technological advances that would be required for emerging resource options to develop at costs below the inflection point before 2030, these results suggest that the near-term resource additions of the Preferred Portfolio (particularly within the Action Plan window) are robust and are low regret options despite the potential for emerging technologies to disrupt resource additions in the long-term.

11.6 Informational community benefits indicators

PGE reviewed the three CBI pathways with community members and environmental justice (EJ) communities.[317] We began development of Information Community benefits indicators (iCBIs) applying Attachment A from Order 22-390.[318] By providing an initial synthesis of potential focus areas from a diverse group of energy advocates, the attachment provided a starting point for CBI development which was supplemented and refined through our engagement process.

As we continue to engage with our communities through our Community Learning Labs, and as we develop experience designing and implementing CBRE resources, we will leverage Attachment A and additional CBIs identified through our community engagement efforts. **Table 26 (Interim CBI metrics and roadmap for future development)**, found in **Section 7.1, Community benefits indicators (CBIs)**, provides an overview of the interim CBIs for the three, identified pathways that have resulted from our work so far. As we heard from our engagement sessions, PGE will update and refine these metrics through our ongoing community engagement efforts. In addition to this work, we conducted research to address Reduction in High Energy Burden and Weatherization, discussed various methods to value these benefits and what PGE needs are to calculate these values (see **Section 7.1.6, Informational community benefits indicators**, for more details).

[317] PGE defines Environmental Justice communities as communities of color, communities experiencing lower incomes, tribal communities, rural communities, coastal communities, communities with limited infrastructure and other communities historically excluded in public processes and adversely harmed by environmental and health hazards, including but not limited to seniors, youth and persons with disabilities.
[318] *See* Docket No. UM 2225, Order No. 22-390 (Oct 25, 2022), Attachment A at 65, available at: https://apps.puc.state.or.us/orders/2022ords/22-390.pdf

11.7 Sensitivities

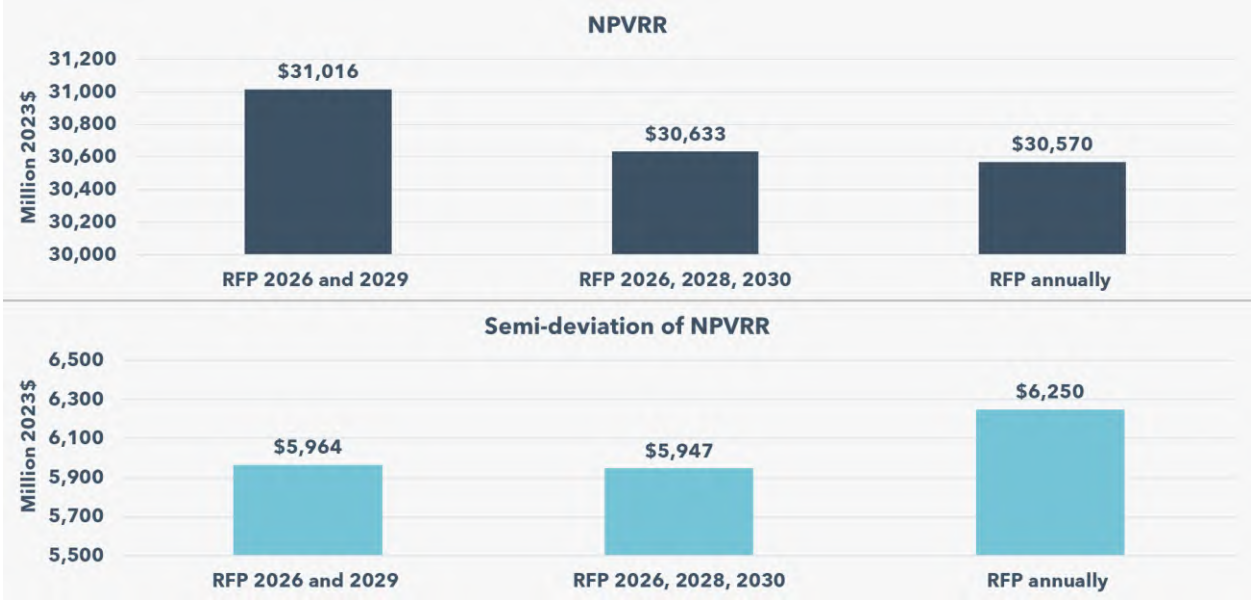
11.7.1 RFP size

Considering the unprecedented increase in the need for resource procurement to accomplish system decarbonization, further examination is needed to evaluate the timing of RFPs. To explore this topic, PGE conducted an analysis of the cost and risk impacts when the Preferred Portfolio is subjected to alternative RFP cadences and magnitude of procurement (**Figure 107**). Three scenarios were analyzed considering alternative procurement schedules by imposing constraints on annual procurement quantities through 2031 (**Table 67**). Aside from the procurement constraints, the portfolio's details match that of the Preferred Portfolio with the exception that all three RFP-size portfolios were not subjected to the energy surplus constraint to facilitate large resource additions where needed. Removal of the energy surplus constraint is necessary to allow the model to concentrate resource additions in 'RFP years', potentially adding more energy than is needed in that year to have sufficient energy in subsequent years when resource additions cannot be made.

Table 67. Procurement constraints through time in RFP size and timing scenarios

Year	Maximum annual resource addition					
	RFP 2026 and 2029		RFP Annually		RFP 2026, 2028, 2030	
	Renewables (MWa)	Storage (MW)	Renewables (MWa)	Storage (MW)	Renewables (MWa)	Storage (MW)
2026	1,000	800	180	133	400	267
2027	0	0	180	133	0	0
2028	0	0	180	133	400	267
2029	1,000	800	180	133	0	0
2030	0	0	180	133	400	267
2031	0	0	180	133	0	0

Figure 107. Cost and risk of RFP size and timing scenarios



Results of the analysis show that the case in which resource additions are limited to occurring only two times before 2032 (RFP 2026 and 2029) produces the largest costs (**Figure 107**). This result is intuitive because this case constrains the model's ability to optimize the timing of resource additions the most, and results in resources being added before they are needed to meet capacity and energy needs. As previously mentioned, the earlier resources are added, the higher costs will be because of discounting in the calculation of NPVRR and the decline in resource costs through time. It is similarly intuitive that the case in which RFP's are conducted annually, 'RFP annually' is the least-cost because the model has the most freedom to match the timing of resource additions to capacity and energy needs. The 'RFP annually' scenario has higher variability than the scenarios in which RFPs are larger and occur less frequently because in some High Need Futures it has higher NPVRR. This is a result of having less ability to match the timing of larger needs with smaller and more frequent procurement. Additionally, adding resources early may increase costs but decreases procurement risk by obtaining resources when they are available, rather than waiting and risking not being able to procure resources when they are needed. As we approach a decarbonization target that is less than 7 years away, we continue to work with regulators and stakeholders to find ways to accelerate the acquisition timeline while retaining an emphasis on engagement and feedback throughout the process. PGE has proposed a streamlined framework for the 2023 RFP within docket UM 2274 and anticipates the need for frequent and nimble procurement

throughout the remainder of the decade.[319] Procurement risk associated with supply chain constraints is explored further in **Section 11.7.2, Supply chain**.

11.7.2 Supply chain

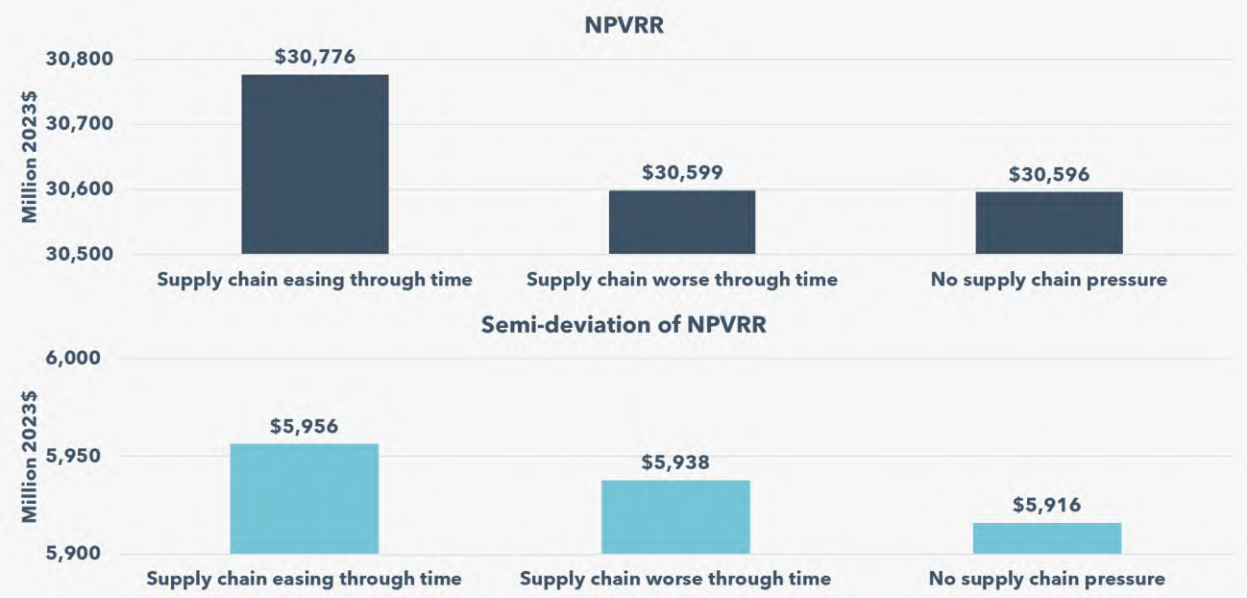
As described in **Section 3.3.3, Supply chain**, PGE's ability to procure new resources is subject to the ability of the complex global system of manufacturing, shipping and construction, known as supply chains, to produce, deliver and install the critical equipment (i.e., solar panels, wind turbines and batteries) used in energy generation facilities. PGE considered the potential impact of supply chain congestion on resource acquisition by imposing two different sets of procurement constraints. The first scenario (Supply chain pressure easing) simulates near-term supply congestions that eases through time, and the second simulates increasing congestion through time (Supply chain pressure increasing). Procurement constraints imposed for the two cases are shown in **Table 68**. The supply chain pressure cases are compared to a case with no procurement constraints, aside from the default set identified in **Section 11.1.6, Procurement constraints**.

Table 68. Procurement constraints of supply chain portfolios

Year	Maximum annual resource addition			
	Supply chain pressure easing		Supply chain pressure increasing	
	Renewables (MWa)	Storage (MW)	Renewables (MWa)	Storage (MW)
2026	150	38	400	228
2027	200	76	350	190
2028	250	114	300	152
2029	300	152	250	114
2030	350	190	200	76
2031	400	228	150	38

[319] *In the Matter of Portland General Electric Company, 2023 All-Source Request for Proposals, Request for Partial Waiver of Competitive Bidding Rules*, Docket No. UM 2274 (filed Jan 31, 2023), available at: https://edocs.puc.state.or.us/efdocs/HAA/um2274haa16364.pdf

Figure 108. Cost and risk of supply chain scenarios



Results of the analysis provide evidence suggesting that supply chain disruptions have the potential to increase the cost and risk associated with acquiring the resources needed for PGE to meet HB 2021 GHG emissions reduction requirements. As can be seen in the cost and risk metrics (**Figure 108**), both cases produce increased cost metrics compared to the unconstrained supply chain portfolio. Near-term supply chain disruptions have a larger impact on portfolio costs and risk than ones that occur further in the future. The larger magnitude of the impact on costs of near-term supply chain disruptions is due to the need to acquire resources earlier than would otherwise be necessary, when discounting has less of an effect and resources are more expensive. While the cost and risk metrics quantified in this analysis are lower if PGE waits to acquire resources, if resource acquisitions are delayed as much as possible, and supply chain disruptions occur closer to 2030, there are risks that the resources necessary to comply with HB 2021 GHG emissions reductions requirements will not be available. This suggests a tradeoff between cost-risk and compliance-risk that PGE must balance.

Chapter 12. Action Plan

Portland General Electric (PGE) developed the Action Plan for the 2023 Clean Energy Plan (CEP) and Integrated Resource Plan (IRP) based on the key findings of the Preferred Portfolio. The Action Plan represents the best combination of cost, risk, community benefits and emission reductions, and outlines the actions PGE proposes to undertake to maintain reliability and meet emissions targets on a planning basis.

Chapter highlights

- PGE's Action Plan proposes a set of resource actions that we intend to take over the next four years.
- The Action Plan is built on the results of the five key components of the Preferred Portfolio that meet long-term system needs and decarbonization targets while minimizing cost and risk and maximizing community benefits.
- Customer resource actions include acquiring forecasted quantities of 'cost-effective' energy efficiency and demand response.
- The pursuit of Community-Based Renewable Energy (CBRE) resources is a cost-effective way to maximize community benefits.
- The energy action conducts one or more Request for Proposals (RFP) for non-emitting energy resources targeting one fifth of the remaining energy need after the addition of EE and CBRE resources.
- A capacity action conducts one or more RFPs targeting the remaining resource adequacy needs in 2026 after contributions from CBRE and other energy resources as well as bilateral contracts.
- PGE will pursue all options to mitigate congestion on the South of Alston (SoA) flowgate
- The Bethel-Round Butte transmission provides the best alleviation of near-term transmission constraints.

12.1 Key components of the Preferred Portfolio

PGE's 2023 IRP shows near-term actions can be taken that position PGE to meet critical long-term reliability and decarbonization goals. This CEP and IRP present an estimation of system need, an identification of available supply-side options and the analysis of portfolios, all of which explore the challenges and uncertainties in long-term resource planning. The combined analysis resulted in a Preferred Portfolio, which contains a set of incremental resource options found to be the best combination of long-term costs, risks and community benefits. The Preferred Portfolio meets customer needs through five core components: customer resource additions, CBRE additions, energy additions, capacity additions and transmission expansion. These components in the Preferred Portfolio through the Action Plan window are detailed in the following sections.

12.1.1 Customer resource additions

The Preferred Portfolio includes the following customer resource additions:

- All cost-effective EE (forecasted by the Energy Trust of Oregon (ETO))
- All customer DR additions (forecasted by the Distribution System Plan (DSP) Part 2)

These forecasted quantities of EE and DR provide an important method to decarbonize. The energy and capacity these resources provide are especially critical given the market constraints PGE faces as we work toward the emissions targets in 2030 and beyond. While results from portfolio analysis suggest additional quantities of EE could be a cost-effective manner to meet system needs, the near-term cost pressure and risk of resource non-procurement led their maximum additions in the Preferred Portfolio to be limited to the cost-effective levels displayed in **Table 69**.

Table 69. Cumulative customer resource additions[320]

	Reference Case					Low need					High need				
	2026	2027	2028	2029	2030	2026	2027	2028	2029	2030	2026	2027	2028	2029	2030
Energy Efficiency (MWa)	90	120	150	183	216	90	121	153	186	221	90	120	150	181	212
Summer Demand Response (MW)	183	199	211	218	228	278	282	287	287	294	126	141	155	166	177
Winter Demand Response (MW)	137	149	158	167	174	183	188	192	199	205	92	104	115	126	134

12.1.2 Community-based renewable energy additions

The portfolio analysis in this IRP included both CBRE resources and contractual transmission constraints. Combined, the economic conditions suggest that while proxy CBRE resources evaluated are generally higher cost than utility-scale proxy resources, their location on-system makes them an effective means in portfolio analysis to reduce cost and risk. **Table 70** summarizes the cumulative of CBRE resources in the Action Plan window.

Table 70. Cumulative CBRE resource additions[321]

	2026	2027	2028	2029	2030
CBRE Additions (MW)	66	85	110	132	155

[320] Demand response estimates are comprehensive of all existing and incremental PGE DR programs.
[321] CBRE additions are equal in each need future

12.1.3 Energy additions

To meet House Bill (HB) 2021's 2030 emissions target, PGE has estimated the Reference Case need to acquire 905 megawatt average (MWa) of incremental generation. The Preferred Portfolio has identified a set of proxy resources that can plausibly be added between now and 2030 given market economics and transmission constraints. This set of resources, displayed in **Table 71**, takes advantage of technological and geographic diversity to meet system needs at the lowest combination of cost and risk.

Table 71. Cumulative energy additions by type in Preferred Portfolio (MW)

	Reference					High					Low				
	2026	2027	2028	2029	2030	2026	2027	2028	2029	2030	2026	2027	2028	2029	2030
Wind	227	627	901	1,172	1,334	403	803	1,136	1,228	1,440	29	429	660	1,128	1,128
Solar	0	0	0	490	756	58	58	58	929	1215	0	0	0	69	529
Hybrid	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CBRE	66	85	110	132	155	66	85	110	132	155	66	85	110	132	155
Contract Extension	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200

12.1.4 Capacity additions

While the energy additions described previously do contribute capacity to the system, to maintain resource adequacy additional resources are needed. **Table 72** displays the total dispatchable capacity additions in the Preferred Portfolio depending on Need Future, while **Table 73** depicts the capacity contribution of each resource type.

Table 72. Cumulative incremental dispatchable capacity (MW) in Preferred Portfolio

	Reference					High					Low				
	2026	2027	2028	2029	2030	2026	2027	2028	2029	2030	2026	2027	2028	2029	2030
4-hr Batteries	232	232	232	232	264	503	503	503	503	503	176	176	176	176	288

Table 73. Approximate capacity contributions by resource type (MW) in Preferred Portfolio[322]

	Reference				
	2026	**2027**	**2028**	**2029**	**2030**
Storage	157	157	157	157	157
Wind	95	162	268	293	498
Solar	0	0	0	77	127
Hybrid	0	0	0	0	0
CBRE	32	41	53	65	75
Tx Market Access	33	33	33	33	198
Contract Extension	200	200	200	200	200

12.1.5 Transmission expansion

Incorporating contractual transmission limitations into portfolio analysis highlights an insufficient capacity of the existing transmission system to meet PGE's system needs. Declining emission targets increase the need for non-GHG-emitting resources. Those resources are generally located in areas that currently lack sufficient transmission capability to move energy to PGE's load. To maintain reliability while meeting emissions targets, additional transmission options are needed. PGE evaluated two types of proxy resource additions: improvements that enable additional resources with PGE's historical geographic area of investigation (located in Oregon, Washington and Montana) and additions that provide access to resources farther away (Wyoming and Nevada). Portfolio analysis demonstrated that the alleviation of the SoA constraint on BPA's system is the most cost-effective manner to meet system needs. Further, the option of regional expansion offers an effective means to access non-emitting energy and capacity. **Table 74** displays the quantities of transmission expansion in the Preferred Portfolio.

[322] The capacity contribution of NV and WY Tx expansion each show up in two locations. Capacity contribution from the associated VERs are accounted for in solar and wind, respectively. Capacity contribution from market access is accounted for in Tx market access. When combined, the ELCC of each Tx expansion proxy is 100 percent.

Table 74. Cumulative transmission additions in Preferred Portfolio

	Reference					High					Low				
	2026	2027	2028	2029	2030	2026	2027	2028	2029	2030	2026	2027	2028	2029	2030
SoA	0	400	400	400	400	0	400	400	400	400	0	400	400	400	400
Wyoming	44	44	44	44	206	100	100	100	100	312	0	0	0	0	0
Desert SW	0	0	0	0	49	58	58	58	58	205	0	0	0	0	0

12.2 Action Plan

PGE's 2023 CEP and IRP Action Plan builds on the key components from the Preferred Portfolio highlighted previously. The five actions detailed in the following sections encompass a set of low-risk, near-term actions that provide the best combination of cost, risk, and community impacts while meeting system need and positioning the company on a pathway to meet HB 2021 emissions targets in 2030 and beyond.

12.2.1 Customer resource action

Customer participation continues to be a critical piece in achieving long-term decarbonization at the lowest cost to customers. PGE will pursue the incorporation of the quantities contained in the cost-effective forecasts of both Energy efficiency (EE) and Distributed energy resources (DERs). These non-emitting resources will provide both energy and capacity to the system.

- Action 1A. Acquire all cost-effective EE

PGE plans to acquire all cost-effective energy efficiency, which is currently forecast to be a cumulative 150 MWa through 2028.

- Action 1B. Incorporate customer additions

We plan to enroll distributed flexibility resources that customers choose to provide. By 2028, this is currently forecast to be a total enrollment of:[323]

- 211 MW of summer demand response (Low: 173 MW, High: 343 MW)
- 158 MW of winter demand response (Low: 127 MW, High: 234 MW)

12.2.2 CBRE action

PGE plans to conduct an RFP for CBRE resources. While the proxy CBRE resources modeled in the IRP presents a higher cost resource than more traditional utility-scale resources, both the inclusion of an rCBI credit and the reflection of existing contractual transmission constraints generate results that suggest distribution-connected CBRE resources are part of the least-cost and -risk set of resource additions. The project evaluation and scoring in this CBRE RFP will be guided by the developing Community benefits indicators (CBI) performance metrics and community feedback received from the Community Learning Labs.

- Action 2: Initiate a CBRE-focused RFP

PGE will conduct a CBRE RFP targeting 66 MW of CBRE resources to come online by 2026 and additional RFP(s) as necessary to support a trajectory towards achieving PGE's goal of 155 MW of CBRE resources by 2030 155 MW in 2030. PGE should continue to pursue federal and state grant opportunities that may help to reduce the costs of CBRE projects and work with customers and communities to develop future potential CBRE programs.

12.2.3 Energy action

Under HB 2021's 2030 carbon emissions targets a significant amount of incremental non-emitting generation will be necessary. The energy action is focused on PGE procurement of sufficient resources to meet projected energy needs.

- Action 3: Conduct one or more energy RFPs

PGE will conduct one or more RFPs to add sufficient non-emitting resources to meet the emissions targets established in HB 2021. The current Reference Case 2030 energy need is 905 MWa; PGE will target acquiring one fifth of that need (181 MWa) each year in the Action Plan (2026-2028), for a total of 543 MWa through 2028. While the customer actions (EE and DR) are reflected in these forecasts, the CBRE resources targeted previously will contribute to these acquisition targets, reducing the total need up to a forecasted 29.6 MWa (to approximately 875 MWa, or approximately 175 MWa per year). PGE will update energy

[323] Demand response values include existing programs.

needs as new information about load growth, resource acquisitions and any applicable changes to policy become available throughout the CEP/IRP and RFP processes.

12.2.4 Capacity action

Maintaining resource adequacy will be critical as we make progress on decarbonization. This action seeks to provide sufficient capacity to the system to ensure reliability.

- Action 4a: Pursue capacity opportunities in the bilateral market
- Action 4b: Conduct one or more capacity RFPs

The 2023 CEP and IRP forecasts significant capacity needs in 2028: 624 MW and 614 MW are needed in the summer and winter, respectively. Elevated and reduced projections of load growth, electrification, DER adoption and market access suggest this need could grow to 786 MW and 864 MW or shrink to 435 MW and 359 MW in the summer and winter. Like the energy action, the cost-effective EE and DER targets in the customer action are already incorporated in this need. While the CBRE and other energy resources described previously could help meet this need, resource additions beyond the CBRE and energy actions are required to maintain resource adequacy. This action will focus on meeting those resource adequacy needs. PGE will pursue the procurement of these resources in a staged approach, first acquiring any beneficial opportunities in the bilateral market, and second by conducting one or more RFPs to meet any remaining capacity needs through the Action Plan window. Similar to the energy action, PGE will update capacity needs throughout the CEP/IRP and RFP processes as new information on both generation supply and demand becomes available.

12.2.5 Transmission expansion action

Assessing the projected growth in demand compared with the characterization of the existing transmission system emphasizes that PGE cannot wait take action to address the transmission concerns described above. Delay could significantly increase projected cost and risk to PGE customers and the energy system. PGE will undertake a multi-phase approach to explore all potential options and pursue those that allow us to reliably decarbonize at the lowest cost and risk.

- Action 5A: Pursue options to alleviate congestion on the SoA flowgate

As discussed in **Section 11.4.2, Transmission portfolios**, the alleviation of the transmission constraints imposed by the SoA flowgate would provide the most effective way to increase the existing transmission system's ability to meet PGE system needs. This action will help enable PGE to add the required off-system non-emitting capacity proposed in the previous actions.

- Action 5B: Explore options to upgrade the Bethel-Round Butte line (from 230 to 500 kV)

As outlined in **Section 9.4.3, Bethel to Round Butte upgrade for future load service**, upgrading the Bethel-Round Butte transmission infrastructure would alleviate transmission congestion and enable critical incremental direct access to solar and wind resource-rich parts of Oregon, and create connections with neighboring transmission providers and western markets.

12.3 Request for Proposals

PGE intends to issue an all-source RFP in 2023 to procure non-emitting energy and capacity resources that can achieve commercial operations by the end of December 2025 to support capacity needs and also acquire renewable resources to further progress towards meeting HB 2021 decarbonization goals. After filing the notice and waiver in January 2023, PGE anticipates the following key milestones:

- February-June 2023: Procedural schedule set, PGE files draft RFP, review and feedback on draft RFP from stakeholders, Commission consideration of approval of draft RFP
- July/August 2023: RFP issuance to market
- December 2023: Final shortlist acknowledgement
- Q1-Q2 2024: Execute definitive agreements with bids on the final shortlist

The timeline used for past resource acquisitions is insufficient to meet the anticipated 2026 capacity need and HB 2021's targets in a manner that achieves balance of minimizing cost and risk and maximizing benefit. Both the current planning process, which was estimated within UM 2225 to take 30 months (about 2 and a half years), and recent procurement processes, which have taken approximately 18 months (about 1 and a half years), are unwieldy when faced with a relatively short procurement window. The procurement timeline sought by PGE in UM 2274 is intended to streamline the resource procurement process while retaining robust opportunities for regulatory review and feedback.

In the last RFP, under the competitive bidding rules (UM 2166), PGE followed a "track one" approach in which the IRP was reviewed and acknowledged, the RFP scoring methodology was vetted in the IRP, and then the RFP was drafted, reviewed and approved.[324] Given the anticipated 2026 capacity need, a track one schedule where the scoring and modeling methodology is vetted in the IRP is not workable to acquire resources specified in the Action Plan in a timely enough manner.

[324] *In the Matter of Portland General Electric Company, 2021 All-Source Request for Proposals*, UM Docket No. 2166, Order No. 22-315 (Aug 31, 2022), available at: https://apps.puc.state.or.us/orders/2022ords/22-315.pdf

Instead, in UM 2274, PGE has proposed a "track two" approach in which the 2023 RFP would be reviewed in parallel with the Commission's acknowledgement process of PGE's 2023 CEP and IRP. PGE's 2023 CEP and IRP docket would run in parallel with the 2023 RFP, which would culminate in anticipated Commission decisions regarding acknowledgment of the 2023 CEP and IRP, and 2023 RFP final shortlist in December 2023. While the regulatory review of the 2023 CEP and IRP, and the 2023 RFP would run in parallel, PGE anticipates that the ultimate procurement volume will align with the 2023 CEP and IRP Action Plan once PGE's resource plans are acknowledged.

To work toward the resource volume necessary to meet the HB 2021 decarbonization targets, it is in the best interest of customers for PGE to take steps now through more nimble acquisition processes as opposed to a cadence that would lead to future procurements closer to the end of the decade when we approach compliance obligations. The preferred resource strategy in this IRP highlights that from a portfolio perspective, balancing regulatory, operational, financial and resource procurement risks point to the advantages of a linear decarbonization pathway rather than one that delays acquisition until just before the 2030 compliance window.[325] Meeting this linear reduction pathway will necessitate substantial procurement of non-emitting resources throughout the decade. Layering procurement throughout the decade and achieving linear carbon reduction is also likely to provide the best opportunity to add resources that offer an optimal combination of geographic location, resource characteristics, advancements in technology and access to needed transmission rights.

12.4 Conclusion

The 2023 Action Plan and RFP are designed to reflect PGE's values and our commitment to serving customers with low-cost and clean technologies while mitigating future risks. The Action Plan was developed by estimating system resource need using forecasts of long-term demand and projections of generation from existing and contracted assets. The difference between that estimated demand and existing supply forms the basis of our forecasted system need. To fill that need, we first evaluated all available options and their potential costs and benefits in our system. We then tailored portfolio analysis to answer the most critical questions PGE faces in long-term planning, comparing the relative performance of portfolios with various combinations of supply-side options. A Preferred Portfolio was created with the best set of incremental resource additions that met system needs while minimizing cost and risk, while maximizing community benefits. Finally, an Action Plan was created to act on the key near-term drivers of the Preferred Portfolio. Concurrently with these actions, PGE will

[325] See PGE's January 26, 2023 IRP roundtable discussion, slide 78, available at: https://assets.ctfassets.net/416ywc1laqmd/68igRlq3sE4VQ9CSEK4r5P/c6982aeef3768c5d645ba8f3716be18a/IRP_Roundtable_January_23-1.pdf

continue to work to specify sources of market purchases and accompanying emission rates, utilize funding opportunities to mitigate customer price pressure and implement transmission upgrades within PGE's Balancing Authority and connecting to BPA's system. These actions provide clarity on our priorities and become a tool for future conversation with customers, stakeholders and the Commission.

Chapter 13. Resilience

This chapter provides Portland General Electric's (PGE's) approach to resilience-related analysis as outlined in the Public Utility Commission of Oregon's (OPUC's) UM 2225 resiliency-specific guidelines, which requires the first Clean Energy Plan (CEP) to include a chapter or other narrative describing its resiliency-related analysis.[326] This includes detailing how PGE coordinated with communities and stakeholders, identifying resilience risks and opportunities, and describing the key resilience-related programs and opportunities PGE will prioritize to support community-based renewable energy (CBRE).

Chapter highlights

- PGE used existing risk assessment analysis regarding system and customer resilience, including energy equity work conducted through PGE's Distribution System Plan (DSP).
- PGE's current and potential resilience programs and opportunities are needed to anticipate, adapt to, withstand and quickly recover from disruptive events.

13.1 Resilience overview

PGE defines resilience as our ability to anticipate, adapt to, withstand and quickly recover from disruptive events. PGE plans for the resilience of our system by identifying critical risks related to generation, transmission, distribution, physical security and information technology operations. We align our resilience efforts and plans across multiple functions and business lines where feasible. PGE's goal is to develop strategies that contribute to community resilience across all of our planning environments. As contemplated by the OPUC's UM 2225 guidelines for the CEP, we considered and differentiated actions related to other plans, such as Distribution System Plan (DSP) and Wildfire Mitigation Plan (WMP) analysis.

[326] In the Matter of Public Utility Commission of Oregon, House Bill 2021 Investigation into Clean Energy Plans, Docket No. UM 2225, Order No. 22-390 (Oct 25, 2022), Appendix A at 40, available at: https://apps.puc.state.or.us/orders/2022ords/22-390.pdf

In this chapter, PGE describes how our planning efforts seek to advance resilience across three focus areas. Additional information related to these three areas can be found within our DSP Part 1.[327]

- **PGE infrastructure resilience:** investment in infrastructure, such as grid hardening, integrated grid and energy supply hardening that mitigates the occurrence of outages during a disruptive event such as a heatwave, wildfire, wind or ice.
- **Operational resilience:** improvements in PGE's ability to meet customers' needs during disruptive events and accelerate service restoration through emergency preparedness, outage response, cybersecurity and customer support.
- **Customer infrastructure resilience:** investigation into customer-sited solutions, such as microgrids, batteries and other distributed energy resources (DERs), that provide customers the ability to maintain electric service during disruptive events, during normal conditions and provide services to the grid.

13.2 Evaluating resilience risks

Recent seasonal trends in peak load and associated uncertainties around future climate change impacts make it more important than ever to consider multiple factors, such as our system constraints, community needs and climate change, in a holistic approach to providing customers with safe, reliable and resilient power. In the summer heat wave of 2021, PGE's net system load broke prior records on four days, making PGE a summer peaking utility. Winter loads continue to increase, with a new winter net system peak load set on December 22, 2022. PGE continues to see an increased frequency and impact of weather events on the system; we had 16 Major Event Days (MEDs) in 2021 and nine major event days in 2022.[328] In analyzing the data over the last 10 years, the largest contributors of weather-related outage events occurred from 2020 through 2022. In addition, these trends raise important issues pertaining to how utilities are expected to understand and incorporate the different community zone of tolerance levels (see **Section 13.3, Zone of tolerance**) when evaluating risk reduction and resilience investments.

As described below, PGE has taken multiple steps toward evaluating risks related to climate change and natural disasters. PGE also works to improve regional safety by reducing wildfire risk while limiting the impacts of Public Safety Power Shutoff (PSPS) events on customers and increasing the resiliency of PGE operations in the face of wildfires. We continue to build on

[327] PGE's DSP Part 1, Resiliency Chapter, available at: https://assets.ctfassets.net/416ywc1laqmd/4nOQVHQGlgbCRAAZWNpuEd/946827f45bb6859133a151a052578778/DSP_2021_Report_Chapter5.pdf.
[328] PGE utilizes the definition of Major Events, Major Event Days and reliability metrics from IEEE 1366-2022.

the work in our DSP and Wildfire Mitigation Plan (WMP) to evaluate resilience risks and strengthen our capacities and system resources to minimize risks, stresses and shocks to the system.[329]

13.2.1 Natural disaster risk assessment methodology

13.2.1.1 Transmission & distribution (T&D) seismic risk assessment

Substations are designed in accordance with the seismic requirements and recommendations of a number of standards, codes and guidelines. New foundations and structures are designed to meet the requirements of ANSI/ASCE 7 and the Oregon Structural Specialty Code. Substation equipment is specified to meet the high seismic requirements of IEEE 693. Substation physical designs follow industry best practices for seismic performance, such as flexible jumpers, equipment anchorage and seismic bracing.

In 2019, PGE developed a proof of concept to systematically assess seismic risk across our system to craft rational, economically prudent risk reduction investment plans. The study analyzed ground shaking caused by a magnitude 6.8 earthquake in Portland Hills, which would impact the Portland urban area of PGE's service area. We presented our proof-of-concept to the OPUC at a special public meeting on January 15, 2019.[330]

The goal was to assess the likelihood of asset failure, its impact on the grid and evaluate the feasibility of scaling the proof-of-concept model. The study determined that the likelihood of an electrical asset failing during a seismic event is largely determined by ground shaking and the asset's structural integrity. The results suggested that rather than model all critical assets, PGE should pursue an incremental approach focusing first on evaluating the seismic risk and resilience associated with oil circuit breakers (OCBs) and the relevant mitigations. OCBs were chosen because they are susceptible to failure with ground shaking and present a significant age-based reliability risk. To mitigate these risks, PGE is in the process of approving funding for a proactive OCB replacement program, which will remove these breakers from the system.

[329] PGE's DSP and WMP, available at: Distribution System Planning | PGE (portlandgeneral.com) and Wildfire Safety | Wildfire Prevention Measures | PGE (portlandgeneral.com).
[330] PGE's presentation to the OPUC, available at: https://statics.teams.cdn.office.net/evergreen-assets/safelinks/1/atp-safelinks.html.

13.2.1.2 Generation seismic risk assessment

In 2014, PGE conducted a focused seismic risk and assessment of our hydroelectric facilities. Through established practices and regulatory requirements, the existing dam structures were known to be capable of withstanding a Maximum Credible Earthquake (MCE) produced ground shaking.[331] Powerhouse structures are not included in the evaluation of the dam. However, the powerhouse infrastructure is critical to the safe passage of river flows and is likely a critical generation asset following an earthquake event.

Powerhouse structures were screened based on construction type and features vulnerable to ground motions. Outdoor powerhouses such as Round Butte, Pelton and North Fork were expected to perform well and within their elastic range, with reinforced concrete operating floors and protective structures over the generating units. Oak Grove, Faraday, River Mill and Sullivan powerhouses have a building enclosure and overhead bridge cranes. These structures were found to have sufficient mass, which could lead to a progressive failure and limit the ability to operate and pass flows.

For River Mill, Oak Grove and Sullivan, PGE evaluated the building performance for these structures based on the American Society of Civil Engineers (ASCE) 41 Seismic Evaluation and Retrofit of Existing Buildings. Initial screening procedures highlighted deficiencies in the lateral load-resisting system. A deficiency-based upgrade could be designed to achieve an Immediate Occupancy (IO) level of performance. Faraday could not be upgraded based on construction type. Faraday powerhouse was unreinforced masonry (URM) which is not allowed based on the site-specific design parameters. Reconstruction was the only alternative.

13.2.1.3 Community assessment

In 2022, PGE studied how seismic risk can be addressed from a customer-centric point of view. As a portion of PGE's DSP, we developed a framework for applying resiliency indicators (including seismic risk) to our Equity Index. We overlayed the Equity Index to the forecasted DER adoption at the census tract level within PGE's service area to highlight how this data might be used to develop targeted customer resiliency programs and initiatives.[332]

The seismic risk component of the Equity Index was included along with other factors such as wildfire and flood risk. To develop an Equity Index metric for seismic risk to customers, we

[331] Information about Maximum Credible Earthquake available at: https://www.ussdams.org/glossary_definition/earthquake-maximum-credible-mce/

[332] PGE's DSP Part 2, Equity Index and Community Targeting Assessment, available at: https://assets.ctfassets.net/416ywc1laqmd/79djvul6i8euOlXwjj1ba5/ffb773d38fa86b08ad1c11f9c7058fff/DSP_Part_2_-_AppendixN.pdf.

required data available for the entire service area. Therefore, we based our initial scoring on publicly available spatial seismic data from the US Geological Survey. The data reflects the peak acceleration value, which estimates the worst amount of shaking in about a 500-year time frame. As we move forward, we will reassess the seismic risk indicators in our Equity Index for customer risk assessment by evaluating the inclusion of new variables, like the OCBs described in **Section 13.2.1.1, Transmission & distribution (T&D) seismic risk assessment**.

13.2.2 Climate change vulnerability assessment

Climate change is considered as a cross-cutting factor (not as a standalone risk), possibly increasing the frequency and intensity of extreme weather, and increasing weather-related natural disaster risks. For example, when evaluating current generation, transmission and distribution risks during the energy supply-demand imbalance risk assessment, climate change was considered as a potential risk driver, making it a cross-cutting factor that impacts multiple enterprise-level risks. The specific risk events identified in that assessment were an ambient temperature-related generation derate or outage during a heat event, transmission outage during a heat event and widespread distribution interruptions due to an ice storm. In two cases, climate change was seen as potentially increasing the frequency and intensity of the event itself. In the other, it was acknowledged that climate change might increase the event consequences.

As noted in the 2023 WMP, PGE continues to further build upon its understanding of climate change impacts on wildfire risk and has leveraged fuel ecology and wildfire studies for the Willamette Valley and Oregon to develop variables to reflect these future projections. Our 2023 WMP was filed with the OPUC in December of 2022 and is pending review by the OPUC.

13.2.2.1 Oregon State University projections of extreme weather study

Historically, we have designed our transmission and distribution (T&D) system according to weather cases identified in the National Electrical Safety Code or based on actual events that struck the service area. However, climate change is likely to contribute to changes in the frequency and intensity of high-impact extreme weather events and past extremes may not accurately indicate future extremes. To increase PGE's understanding of the impacts of climate change on the distribution and transmission system, we worked with the Oregon Climate Change Research Institute and Oregon State University (OSU) to conduct a study. The study was designed to project extreme heat, extreme wind, freezing rain and ice accumulation within our service area through 2070 or beyond. The climate study was based on two different Representation Concentration Pathway (RCP) emissions scenarios (RCP 4.5 & RCP 8.5). The two RCP scenarios provided insight into two different potential climate futures

to better prepare for a variety of potential outcomes. The study results are being evaluated to determine if changes to the design and construction standards of PGE's T&D are warranted.

13.2.3 Reliability metrics

Traditionally, System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI), Customer Average Interruption Duration Index (CAIDI) and Momentary Average Interruption Frequency Index (MAIFI) are utility-centric reliability metrics that focus on the average grid performance. Customer-focused metrics such as Customers Experiencing Multiple Interruptions (CEMI) and Customers Experiencing Long Interruption Duration (CELID) are used to identify customers experiencing more frequent or prolonged duration interruptions.

PGE has started to augment the more traditional system-wide metrics with customer-centered metrics in analyses to identify the need for system improvements. Metrics like CEMI and CELID provide a more accurate picture of the reliability experienced by our most impacted customers. Traditional reliability metrics exclude MEDs, allowing a utility to compare grid performance year over year, regardless of variation in weather patterns. As PGE identifies opportunities to improve resilience, CEMI and CELID are calculated, including MEDs, to provide a clear picture of customer experience during disruptive events.

13.2.3.1 Value of service

As part of PGE's customer-centered risk-informed methodology, we leverage Pacific Gas & Electric's (PG&E's) 2012 reliability-based Value of Service (VOS) study approved by the California Public Utilities Commission (CPUC). [333] PGE has since escalated the 2012 values to 2022 dollars using the US Bureau of Labor Statistics' (BLS') CPI Inflation Calculator.[334] These VOS values are intended to reflect the baseline economic impact the different customer classes (residential, commercial and industrial) experience from an outage.

The VOS values have two components:

- **Interruption cost** ($/kilowatt (kW) economic impact of an outage regardless of the duration), and
- **Duration cost** ($/kilowatt-hour (kWh) economic impact of an outage duration; up to 24 hours)

[333] PG&E's 2012 Value of Service Study, available at: http://www.caiso.mobi/Documents/AttachmentB_ISOResponsesCommentsDraft2012-2013TransmissionPlan.pdf.
[334] The US BLS' CPI Inflation Calculator, available at: https://www.bls.gov/data/inflation_calculator.htm.

As discussed in DSP Part 2, PGE has developed economic risk models as a tool to identify risk on the system. Risk is defined as the product of failure probability and consequence cost of failure. A consequence of failure includes:

- Type of customer (residential, commercial and industrial)
- Kilowatt load impacted
- Duration of impact
- VOS to customers
- Direct costs to PGE to respond to the outage.

These VOS measures will enable our teams to better understand how customers value both reliability and resiliency and what we should take into account when making decisions.

13.2.4 Community resilience index

As part of PGE's DSP Part 2, we conducted an assessment for considering diversity, equity and inclusion (DEI), environmental and resilience parameters as part of our distribution system planning process.[335] Resilience was based on environmental risk factors, such as wildfire or flood vulnerability areas, and grid/system needs, such as long-term outage locations. Through an assessment, we developed a set of indices needed to understand the geospatial distribution of these parameters within our service area and identify our most affected and vulnerable populations. We researched numerous factors that could explain the relative resilience of different portions of our distribution system. Through statistical and geospatial analyses, we summarized distributions of priority variables for resilience factors within our service area. These results were then statistically evaluated to develop quintile distribution frameworks. Within the study, we also presented a few application examples to show how we can integrate this toolkit into PGE's DER forecast model, AdopDER, and consider approaches for efficient targeting to influence program design, targeted deployment and benefit optimization based on locational factors.

The study aimed to achieve the following steps:

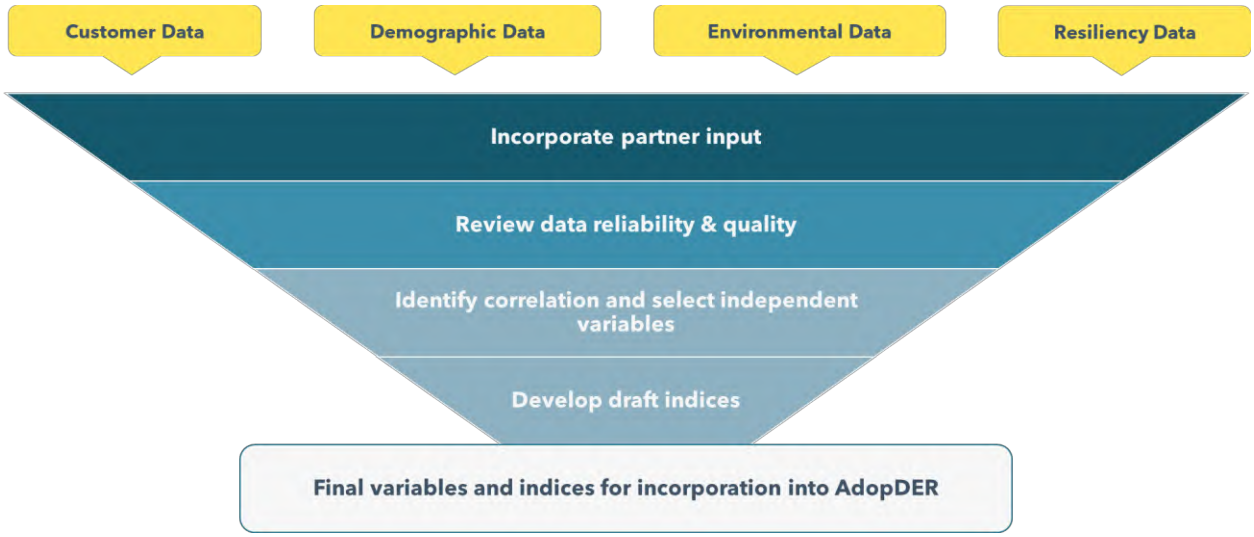
- Review available data sources and solicit stakeholder feedback to identify specific criteria and key variables used to characterize DEI, environmental and resilience parameters.

[335] PGE's DSP Part 2, Equity Index and Community Targeting Assessment, available at: https://assets.ctfassets.net/416ywc1laqmd/79djvul6i8euOlXwjj1ba5/ffb773d38fa86b08ad1c11f9c7058fff/DSP_Part_2_-_AppendixN.pdf.

- Develop a set of indices to account for the various underlying variables and locational elements across DEI, environmental and resilience prioritization areas.
- Summarize results of these indices to identify trends and consider future applications for resource planning, including siting locations for future non-wires solutions.
- Integrate with PGE's AdopDER model as a separate module for considering locational factors of DEI, environmental factors and resilience relative to feeder-level DER adoption forecasts.

Figure 109 provides an overview of these steps used in our approach.

Figure 109. Community targeting assessment approach



We are now proposing to leverage this analysis to target community resilience efforts in resource and program planning. **Table 75** shows the factors that were evaluated and those that were prioritized to develop the Index as part of our DSP Part 2.

Table 75. Data sources from DSP Part 2

Type	Source	Description
Geographic	PGE Shapefile Census Geographies	Define service area boundary and unit of geographic analysis
Income/demographics	ACS, PUMS PGE (CIS/Axiom); Greenlink; US DOE LEAD Tool	Characterize populations using DEI criteria

Type	Source	Description
Environmental	EPA EJScreen	Identify environmental indicators by location
Resilience	PGE (long duration outage locations, PSPS, major events); US Forest Service (wildfire risk); FEMA (flood risk); DOGAMI (seismic risk)	Identify areas at risk for long-term outages due to natural disasters/extreme weather
Customer arrearage	PGE (list of accounts with current and/or historical arrearages, assistance payments, disconnects/reconnects)	Characterize customers using DEI criteria

13.3 Zone of tolerance

The US GMLC's Considerations for Resilience Guidelines for CEPs report describes the "zone of tolerance" as a concept that "has been developed to account for different capabilities of households and communities to endure the adverse impacts of service disruptions."[336]

Through our work on our DSP Part 2, we aimed to develop better data that may enable us to widen the "resilient zone" so we are better able to assess and identify factors affecting risk disparity due to infrastructure service disruptions in wildfire, seismic and extreme weather events. PGE is considering new factors to assess the ability of a particular household or community to cope with service outages that can inform focused actions to increase customer and community resilience.

13.3.1 Energy equity index development

Within PGE's DSP Part 2, we reviewed a large number of factors that could represent the ability of our communities to withstand the effects of long-term outages. This data was then distilled to develop an Energy Equity index to approximate our customer's zone of tolerance. Currently, six energy equity indicators are used for distribution system planning on projects weighting and scoring Energy Burden, Dwelling Type, Owners/Renters, People of Color, households without internet and households with disability.

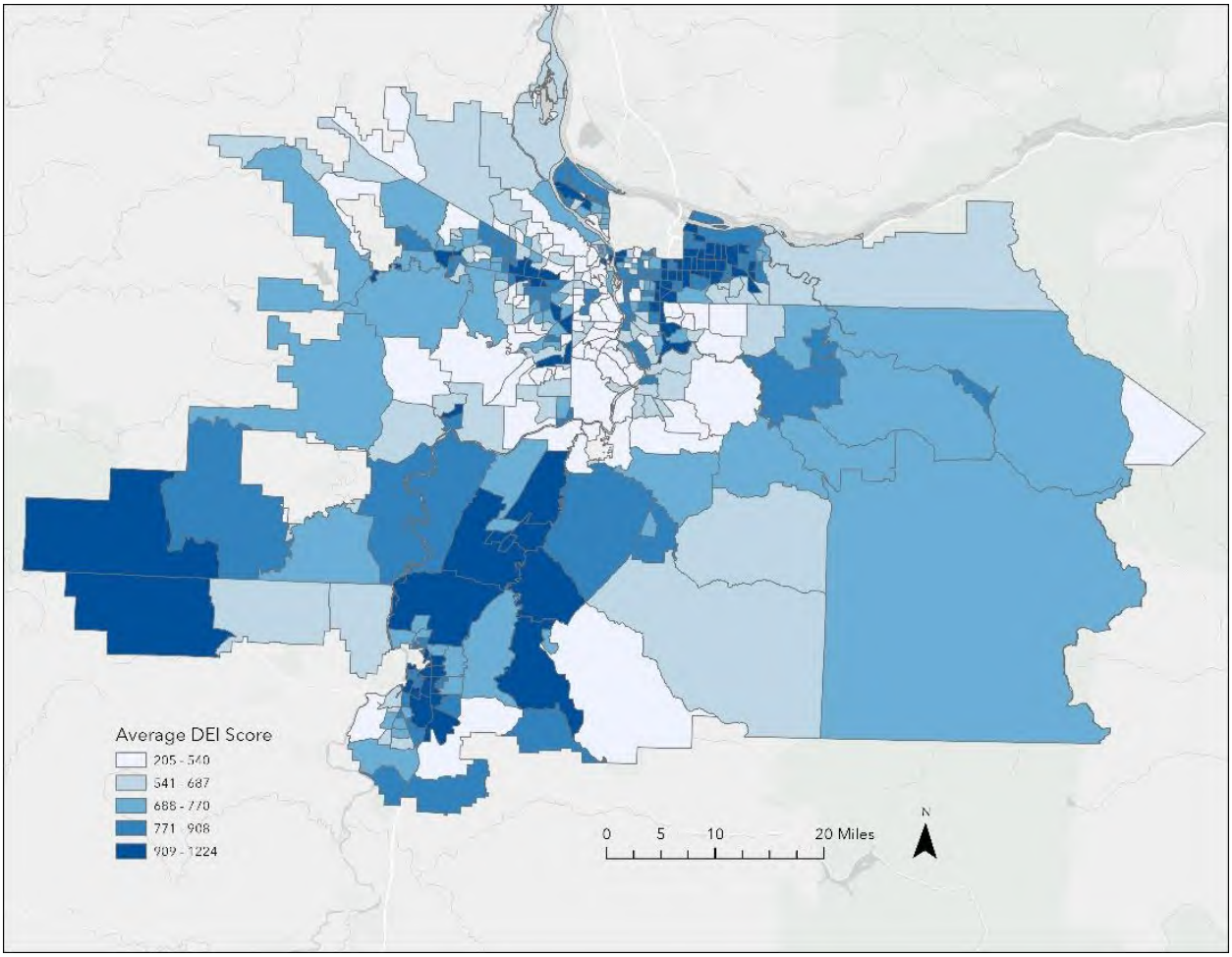
[336] The OPUC's Considerations for Resilience Guidelines for Clean Energy Plans report, available at: https://edocs.puc.state.or.us/efdocs/HAH/um2225hah113046.pdf.

To illustrate an example of this weighting, energy burden received the highest weighting (and associated scoring) within the DEI category. The decision to prioritize this variable over others within the DEI category was a function of the following:

- Latent factor analysis results—energy burden received one of the highest explanatory capacities under the DEI category.
- The community-based organization DSP Community Workshops conducted by PGE in 2022, positioned this variable as highly relevant to determine disadvantaged communities.

Within the energy burden variable, points were allocated based on the geographic distribution of the variable (using quartiles). Thus, to reflect a higher prioritization of energy burden within the DEI index, we assigned the highest score (Q4 value = 300) to premise IDs in census tract areas within the highest quartile of average energy burden. The middle quartiles then received reduced scores (Q3/Q2 values = 150), with the lowest score assigned to the lowest quartiles (Q1 value = -50). Through this approach, customers with a higher energy burden would receive more points than those falling in the middle of the distribution, while customers showing the least amount of energy burden were given negative points. PGE followed a similar approach for other variables; however, those variables with lower prioritization within a category, such as households with internet access for the DEI category, would have a lower point distribution that would effectively result in a lower weight for the index development (i.e., Q4 = 60, Q3/Q2 = 20 and Q1 = -20). Finally, to build the index, we summed or subtracted points for each customer depending on where they sit on the distribution of each variable composing the index (**Figure 110**).

Figure 110. DEI index



13.3.2 Justice 40 initiative

In 2021, President Biden signed Executive Order (EO) 14008 into effect.[337] Section 223 of this EO creates a goal that 40 percent of the overall benefits of certain Federal investments flow to disadvantaged communities (DACs) that are marginalized, underserved and overburdened by pollution.

The US DOE currently has a working definition of disadvantage based on cumulative burden. Thirty-six (36) burden indicators reflect fossil dependence, energy burden, environmental and climate hazards and socio-economic vulnerabilities.[338] PGE is leveraging this data source

[337] *See* Tackling the Climate Crisis at Home and Abroad, 86 FR 7619 (February 1, 2021), available at: https://www.federalregister.gov/documents/2021/02/01/2021-02177/tackling-the-climate-crisis-at-home-and-abroad, and https://www.regulations.gov/document/EPA-HQ-OPPT-2021-0202-0012.
[338] The US DOE's Justice40 Energy Justice Mapping Tool, available at: Energy Justice Dashboard (anl.gov).

as part of its energy equity mapping through its DSP to assist in our equity mapping to identify DAC within PGE's service area. This tool allows access and the opportunity to explore DAC using census tract data. US DOE's Justice40 data illustrates areas that may have greater need, outcomes and impacts. Applying equity indicators to our maps and data may inform decisions for future projects, plans and processes and how they could affect communities.

13.3.3 Medical Certificate Program

The PGE Medical Certificate Program provides awareness of where some customers, who are most vulnerable to a loss of electricity, are located throughout our service area.[339] This program allows a customer that provides us with an accepted medical certificate to set up more lenient payment arrangements or renegotiate payment arrangements when financial hardship can be demonstrated. This program continues the disconnection of service when payment arrangements are not kept and allows PGE to provide better outreach and support to our most vulnerable customers during a resilience event.

In evaluating resilience opportunities in our WMP, we proposed to pilot programs to specifically address the needs of these customers (within this plan, see **Section 13.5.9, Portable storage**). Beyond that direct activity, the location of these customers can provide valuable insight when prioritizing community resilience investments.

13.3.4 Heat vulnerability data

Climate change will continue to impact the frequency and intensity of extreme temperature events. During the summer of 2021, PGE experienced record-setting peak loads as the Portland metro region experienced a "heat dome" lasting several days which shattered historical temperature records. In addition to spikes in cooling-related peak loads, human health and safety risks also increase during extreme temperature events. In response to these extreme heat events, state and local governments responded by pursuing emergency cooling ordinances and response efforts; for example, the City of Portland developed and launched a Heat Response Program, and Oregon passed Emergency Heat Relief legislation to support vulnerable Oregonians.[340,341]

In the midst of this context, PGE initiated a research and development (R&D) project with researchers at Portland State University to study customer heat vulnerability across our

[339] More information on PGE's Medical Certification Program, available at: https://www.oregon.gov/puc/Documents/OregonMedicalCertificateProgram.docx.pdf.
[340]See Portland Clean Energy Fund's Heat Response Program, available at: https://www.portland.gov/bps/cleanenergy/heat-response-program
[341] See SB 1536 (2022), available at: https://olis.oregonlegislature.gov/liz/2022R1/Downloads/MeasureDocument/SB1536/Enrolled

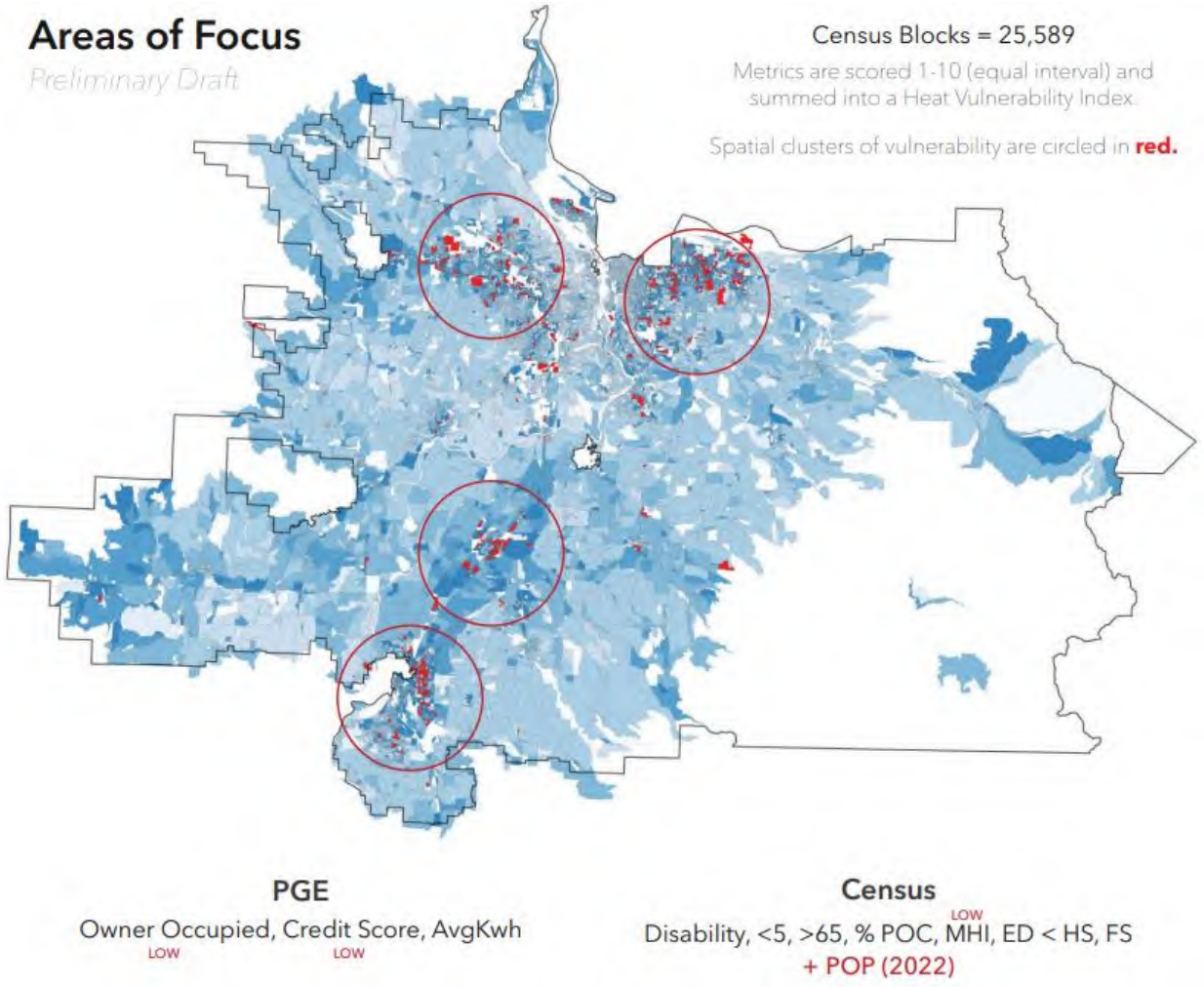
service area. The research builds on Portland State's extensive past efforts to model urban heat island dynamics to inform PGE's distribution grid planning efforts and related customer program development efforts.

The study uses data across environmental, social and built environment indices combined into a Heat Vulnerability Index. Examples of datasets used across these three areas that are known to influence heat vulnerability are:

- **Environmental data:** tree canopy cover, localized heat (temperature), percent of impervious pavement.
- **Social data:** socioeconomic factors (e.g., income, food security), demographics (e.g., race, age) and other factors such as disability data and overall population in a given area.
- **Built environment data:** building type, building age.

We applied the results of the Heat Vulnerability Index to our service area to identify areas of focus for near-term planning efforts. **Figure 111** shows a map of the PGE service area with four main zones of high heat vulnerability, indicating that cooling relief and resiliency initiatives geared at these population zones may significantly bolster customer resiliency during future extreme heat events.

Figure 111. Map of Heat Vulnerability Index scores in the PGE service area



PGE plans to continue socializing the results of our heat vulnerability assessment with municipal entities and communities through our Community Learning Labs and DSP community engagement meetings. In particular, we are interested in exploring the potential synergies between this level of data analysis and different customer DER programs that could alleviate these risks and also present opportunities for managing grid needs. For example, the cluster identified in East Portland in **Figure 111** is overlapping with the grid needs from our concept proposal presented in DSP Part 2 for the Eastport Plaza NWS, as well as the newer grid need identified for Arleta and Holgate substations, which are adjacent to Eastport and still score in high heat vulnerability areas.[342]

[342] PGE's DSP Part 2, Grid Needs Chapter, available at: DSP_Part_2_-_Chapter04.pdf (ctfassets.net).

13.4 Historical reliability data

PGE uses historical reliability performance data to evaluate the system's reliability and resiliency risk. The data informs the failure probability assumptions in the economic risk models for asset-caused and geographic-caused failures and is used to develop potential mitigation solutions. When evaluating risk, PGE considers the factors shown in **Table 76.**

Table 76. Factors considered when evaluating risk

Performance measures	Considered in risk evaluations	OPUC report
All outages (planned, major event or underlying)	Yes	Annual Report on Electric Reliability
Primary initiating event for each major event the utility analyzed	Yes	MED Exception Filing
Top causes for each day during which a major event occurred	Yes	MED Exception Filing
Number of customers out and the restoration performance for their supply	Yes	Annual Report on Electric Reliability & MED Exception Filing
Estimated costs to the utility to recover from the major event	Yes	NA
Estimated unserved energy during the period of a major event	PGE does not yet calculate this value	NA
Demographics of the community, including classification of energy equity or other social or EJ measures	Yes	NA
Estimated impacts to the customers	Yes	NA

Table 76 indicates which factors are also identified within our Annual Reliability Report, shared publicly in OPUC Docket RE 113 in May.[343] Our Annual Reliability Report provides distribution system performance information based on customer service interruptions. The

[343] PGE's Annual Report can be found: *In the Matter of Portland General Electric Company, Annual Reliability Report,* Docket No. RE 113, available at: https://apps.puc.state.or.us/edockets/docket.asp?DocketID=18326.

report is used to understand the overall reliability of the distribution system and to identify areas of improvement.

Within PGE's Annual Reliability Report, we include a definition for outage and outage data, including total outage hours, minutes, top outage causes and major initiating events such as equipment failure, lighting, vegetation, wildlife and weather. Additional detail on historical reliability performance can be found in our Annual Reliability Report. The results for 2022 will be included in our May 2023 filing.

Through Order 22-390, the OPUC provided resiliency-specific guidance that when evaluating resiliency risk, utilities should "rely on measurable historical reliability performance measures such as outage data and major events." PGE relies on historical reliability data already captured within our Annual Report. Moving forward, PGE suggests reliability reporting related to major outage events be included in the Annual Reliability Report rather than in the CEP. While pertinent to analyzing all resilience investments, it does not uniquely impact the resource procurement decisions being evaluated in the Integrated Resource Plan (IRP) and the CEP. Having a separate report to refine existing reported reliability data and the analysis can create confusion and possibly inconsistency between datasets. Additionally, PGE uses the VOS to estimate impacts on the customer. See **Section 13.2.3.1, Value of service**. We also identify and use socioeconomics and demographic data within our DSP Part 2. Specifically, we evaluated demographics as it relates to resiliency within our DSP Part 2, Appendix N, Equity index and community targeting assessment (see **Section 13.3.1, Energy equity index development**).[344]

13.5 Programs and opportunities

During PGE's community engagement process, we discussed potential resiliency analysis, approaches, programs and opportunities. For example, we received positive feedback in our Community Learning Labs that expanding metrics used in project scoring to have a CEMI reduction metric, in addition to the metrics identified in the DSP, may be useful in evaluating potential resilience projects. We will continue to explore these ideas with the community when evaluating resilience projects (such as T&D system projects) for the various benefit streams.

The following descriptions provide examples of the activities we are planning and/or undertaking to enable customers to mitigate the effects of disruptive events and access to the services they need.

[344] PGE's DSP Part 2, Appendix N, available at: https://assets.ctfassets.net/416ywc1laqmd/79djvul6i8euOlXwjj1ba5/ffb773d38fa86b08ad1c11f9c7058fff/DSP_Part_2_-_AppendixN.pdf.

13.5.1 Resilience in other plans

PGE has identified resilience as an important component of our DSP and WMP.[345] These plans have specific resilience programs and opportunities needed to address the modernization of the grid, acceleration of DER, energy equity and wildfire mitigation. PGE's DSP is filed in OPUC Docket UM 2197 and our WMP is filed in OPUC Docket UM 2208.[346]

13.5.2 CBRE potential study

The OPUC issued initial CEP guidance through Order 22-390. This guidance included conducting a CBRE potential study for the initial CEP. As described in **Chapter 7, Community benefits indicators and community-based renewable energy**, PGE conducted a CBRE potential study for this CEP and aims to build on this work to inform future CEPs. PGE intends to conduct a future CBRE potential study that will identify opportunities for CBRE actions, including distributed resources and their resilience benefits, and the study will be developed in coordination with communities, including EJ communities, stakeholders and Staff. PGE intends to coordinate this work, including coordination across other planning efforts, such as our DSP.

13.5.3 EPRI Climate READi: Power resilience and adaptation initiative

PGE understands the need to develop a common framework to understand the impacts of climate risks on the reliability and resilience of energy infrastructure. As such, PGE is participating in the EPRI Climate READi: Power Resilience and Adaptation Initiative. EPRI's initiative will convene global thought leaders and scientific researchers necessary to build an informed and consistent national approach. There are three primary targets for this initiative over the next three years.

- Develop a common approach for using climate data for specific power system assets and system vulnerability assessments, including how to treat the inherent uncertainty in climate variables.
- Identify and assess potential adaptation and mitigation strategies and their impact on risk.

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[345] PGE's DSP and WMP, available at: Distribution System Planning | PGE (portlandgeneral.com) and Wildfire Safety | Wildfire Prevention Measures | PGE (portlandgeneral.com).

[346] *In the Matter of Portland General Electric Company, Distribution System Plan*, Docket No. UM 2197 (filed Oct 15, 2021), available at: https://apps.puc.state.or.us/edockets/DocketNoLayout.asp?DocketID=23043 and *In the Matter of Portland General Electric Company, Wildfire Protection Plan*, Docket No. UM 2208 (filed Dec 7, 2021), available at: https://apps.puc.state.or.us/edockets/DocketNoLayout.asp?DocketID=23111.

- Offer guidelines for risk-based methods for prioritizing risk mitigation investments across generation, transmission, distribution and customer resources.

13.5.4 Smart battery pilot

PGE launched its five-year Smart Battery pilot in 2020.[347] Through this program, PGE works with residential customers with home battery energy storage devices. The program seeks to install and connect residential energy storage batteries that will contribute up to 9.5 megawatt hours of energy to our grid. Once installed, these distributed assets will contribute toward a virtual power plant (VPP) made up of DERs that can be operated individually or combined to serve the grid, adding flexibility that supports PGE's transition to a cleaner energy future. In addition, the energy storage batteries provide customers with a backup energy resource they can rely on in the event of a power outage.

In February of 2023, PGE received approval for a tariff update to the pilot based on learnings from the first two years of operation and to move the pilot closer toward a cost-effective and scalable structure. The update transitioned the ongoing customer payment structure from a flat monthly participation reward toward a pay-for-performance model, giving customers more customization on how we use their battery. The update also adjusts the up-front rebates to reflect the changed boundaries of the Smart Grid Testbed.

Historical information on this pilot can be found within the OPUC's Energy Storage Docket UM 1856.[348] If PGE files any revisions to our Schedule 14, it will also be within Docket UM 1856.[349]

13.5.5 Energy partner on-demand

Energy Partner On-Demand is a demand response (DR) program providing incentives to large nonresidential customers during seasonal peak time events for reducing their load.[350] The program develops highly customized load curtailment plans that can work with a variety of unique types of businesses. In June 2022, the program received regulatory approval to expand upon the grid services that Energy Partner may provide PGE and support customers' resilience and clean energy goals by incorporating battery energy storage as a dispatchable resource.

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[347] PGE Tariff Schedule 14, available at: Microsoft Word 014-21-10 Eff June 2.2021 (ctfassets.net).
[348] *In the Matter of Portland General Electric Company, Draft Storage Proposal,* Docket No. UM 1856, available at: https://apps.puc.state.or.us/edockets/docket.asp?DocketID=20913.
[349] PGE's Schedule 14, available at: https://assets.ctfassets.net/416ywc1laqmd/7rEQyshErHsASDCZZtIjL5/3e00bcdd66fc74c75e9f1a7af8c9efe4/PGE_Advice_No._22-43_Sch_7_and_14_Res_Energy_Storage_Update_OL_12.12.22.pdf.
[350] PGE tariff Schedule 26, available at: Microsoft Word 026 22-35 Eff Jan 1.2023 (ctfassets.net).

13.5.6 Energy partner resilience (dispatchable standby generation)

In 1999, the MacLaren Youth Correctional Facility became the first PGE customer to enroll their standby generator in our Dispatchable Standby Generation (DSG) program. This program is a collaboration with customers that interconnect generation resources, providing electricity to PGE's grid when there is a critical need for power in the local region. Since then, the DSG program has grown to 59 sites with a cumulative nameplate generation capacity of 130 megawatts (MW). While not fuel-restrictive, the bulk of this capacity has historically consisted of internal combustion diesel generators, and we have undertaken a concerted effort to modernize and decarbonize the program by adjusting the program tariff to target the integration of non-emitting energy storage.

PGE has successfully integrated customer-sited batteries for grid services, as demonstrated by the Beaverton Public Safety Center and Anderson Readiness Center. With the increased commercialization of battery energy storage, PGE proposed to build upon those capabilities to expand the DSG program to include battery energy storage systems greater than 250 kilowatts (kW). We received approval to do so in June of 2022.[351] In addition to contingency reserve and frequency response, customers with battery energy storage may opt to also participate in other demand response activities.[352] With the addition of batteries, we branded the program as "Energy Partner Resilience" for customer communications.

This program can now provide the same advanced resilience support to enrolled customers as our legacy DSG program while also supporting our customer's, PGE's and Oregon's decarbonization targets.

13.5.7 Multi-unit microgrid demonstration- Salem smart power center

In 2013, PGE commissioned the Salem Smart Power Center (SSPC), a 5 MW, 1.25 megawatt-hour (MWh) battery energy storage system that, at the time, was part of the largest regional smart grid demonstration project in the nation. As this battery energy storage system

[351] See Docket ADV 1385, PGE Advice 22-05, *Schedule 200 Dispatchable Standby Generation Update* (June 1,2022), regarding the OPUC's approval of PGE's request to include battery storage in our DSG program, available at: https://edocs.puc.state.or.us/efdocs/UBF/adv1385ubf161150.pdf

[352] A flexible load service not currently possible with fossil-fueled resources. Additionally, Contingency Reserve is the portion of resource capacity that is capable of being synchronized and ramping to a specified load in 10 minutes (or that is capable of being interrupted in 10 minutes) and that is capable of running (or being interrupted) for at least 60 minutes from the time it reaches its award capacity. Frequency Response is similar; however, it has a response time at 22 seconds and duration typically less than 1 minute.

approaches its 10-year anniversary and is demonstrating end-of-life characteristics typical of a 10-year-old battery energy storage system, we are evaluating how to evolve the resource best to continue to provide value.[353]

In the Fall of 2022, the City of Salem, in partnership with PGE, received a one million dollar grant from the Oregon Department of Energy's (DOE's) Community Renewable Energy Grant Program. The project is described as follows:

> *A community energy resilience project, in partnership with PGE, to create a solar powered community microgrid with battery storage and electric vehicle charging. The system will connect to a solar array on and serve Salem's new Public Works Operations building and its electric vehicle charging stations, allowing it to function during grid outages. The microgrid will serve 96 apartments in six buildings, 34 homes, one local business, three other government buildings and a cellular communications tower, providing uninterrupted power during grid outages.*[354]

Leveraging the existing building and infrastructure of the SSPC and with a new and modern battery energy storage system, PGE seeks to build the first community microgrid of its kind in the Northwest. We are currently working with the City of Salem to begin construction in 2023 and anticipate the microgrid will be energized in 2024. When complete, the microgrid will provide grid services to support our decarbonization targets and resilience for our communities and critical facilities within the microgrid boundary.

[353] PNNL conducted an assessment of battery performance and economic potential on PGE's Salem Smart Power Center, which can be found at. The Salem Smart Power Center (pnnl.gov).
[354] Oregon Department of Energy, Press Release, October 18, 2022, *Oregon Department of Energy Grant Program Supports Renewable Energy Projects from Ashland to Ontario*, available at: https://energyinfo.oregon.gov/blog/2022/10/18/oregon-department-of-energy-grant-program-supports-renewable-energy-projects-from-ashland-to-ontario

13.5.8 Community resilience hubs

As part of PGE's considered approaches to CBREs, we will leverage existing microgrid projects such as the Beaverton Public Safety Center (BPSC). At BPSC, we are also exploring the use of a portable battery energy storage unit to provide backup power to their electric vehicle fleet in the event of an outage while also having the flexibility to be used for urgent needs elsewhere. This work, along with community collaboration, will help inform potential community resiliency, such as CBREs for critical facilities (e.g., police, fire, EMS, wastewater treatment and water pumping facilities) and local resilience hubs.[355] Any potential programs will aim to work with community and local governments such as municipalities. This collaboration will help us identify microgrid solutions. For example, we are developing analytical approaches to identify CBRE locations. With this data-driven information, we can work with targeted communities to assess their resiliency needs and desired solutions.

With any resiliency solution, such as a microgrid, it is important that the solution be able to act as a locational grid asset during normal conditions and a resilience resource in the event of an outage. We will investigate the potential federal and state funding needed to support the cost of such an investment. Additionally, we aim to co-optimize any flexible resiliency load for the VPP, non-wires solutions and community benefits.

One consideration of any CBRE project is the need to provide direct community benefits. As starting points, some community benefits we may consider are:

- Reduction in recovery time of a local community in the aftermath of a natural or human-made disaster.
- Safety net resource for highly vulnerable households to reduce the negative effects of power outages and extreme conditions
- Increased renewable generation within and for our communities.
- Operational cost savings for host sites that can be passed to community members.

[355] We are defining local resilience hubs as a facility where members of the public may convene in the event of a power outage.

13.5.9 Portable storage pilot

Within PGE's 2023 WMP, we requested a pilot to provide portable energy storage to our most vulnerable customers affected by a PSPS. This program seeks to provide financial support for portable batteries to customers enrolled in our Medical Certificate Program who reside in a designated PSPS area. The objective is to increase resilience for customers dependent on electrically powered medical devices. A portable battery solution also allows renters, multi-unit housing dwellers and those who cannot afford a larger backup system to increase their resilience or those who struggle with other traditional methods (such as propane or diesel generators). Should the OPUC acknowledge this item within our WMP, we intend to request approval to implement the program.

We are exploring utilizing a portable battery unit at the Beaverton Public Safety Center. This portable battery will provide backup power to a panel of electric vehicle chargers. With this work, we will explore operations around the portable aspects of the battery.

13.5.10 Public safety partner engagement program

PGE is a provider of a core service for our communities. We cooperated with the communities in our service area to plan for and respond to emergency situations. Recognizing the importance of this cooperation, our Business Continuity and Emergency Management Team (BCEM) is formalizing a program to encourage and increase our ongoing engagement with the emergency management community, focusing on emergency preparedness and community resilience collaboration.

To achieve this, BCEM engages with public safety partners where we have distribution services and/or assets. Primarily this means interacting with the county emergency management agencies, which can provide a central coordination point for all the sub-jurisdictions, such as cities and special districts. The goals of this program are to:

- Enrich public/private sector emergency management partnerships.
- Enhance mutual readiness through coordinated preparedness activities.
- Strengthen connections between PGE and our communities.

PGE hopes to achieve these goals by increasing our interaction with the local community. We plan to host all-hazards summits to discuss preparedness activities and any specific concerns regarding upcoming seasonal hazards with local emergency managers. Additionally, through individual meetings with County Emergency Managers and participation in regional advisory bodies, we seek to engage with a broad cross-section of the community that is focused on community resilience.

For example, PGE is a member of the Regional Disaster Preparedness Organization (RDPO). The RDPO is a partnership of government agencies, non-governmental organizations and private-sector stakeholders in the Portland Metropolitan Region collaborating to increase the region's resilience to disasters. As resilience programs are developed, we will look to these groups and processes to refine our programs and ensure our communities leverage new resilience initiatives.

13.6 Looking ahead

The GMLC's report provides valuable insight into practices that can inform PGE's future analyses and links to practitioners we can turn to for additional knowledge and lessons learned.

During the ideation stage of our planning, we heard from the community that equity mapping within our investment decision framework is an area of interest. PGE's resiliency planning will continue to be refined as our understanding of our communities and climate change evolve. For example, we are exploring the idea of using maps with multiple layers such as equity metrics, outage information, risk assessment and PGE infrastructure information.

We understand CEPs will evolve PGE's planning practices over time and hope that initial guidance established through the current process accounts for the time needed to engage and collaborate with communities effectively. This includes engaging on such topics as CBIs, resiliency and community-based renewables while balancing the need to quickly procure clean energy resources to meet our decarbonization targets by 2030.

Chapter 14. Community equity lens and engagement

We recognize that climate change often disproportionately impacts our most vulnerable communities, including Black, Indigenous and People of Color (BIPOC) and low-income communities.[356] Prioritizing energy access, reliability and resiliency is more important now than ever, as we see the effects of climate change in real-time across our service area in the form of drought, extreme temperatures, wildfire, habitat loss and destructive storm events. This chapter provides Portland General Electric's (PGE's) approach to the Oregon Public Utility Commission's (OPUC's) Community Lens topic as outlined in the OPUC's UM 2225, which provided guidance on community engagement strategies for the Clean Energy Plan (CEP).[357]

Chapter highlights

- PGE's community engagement strategy and goals for PGE's long-term planning processes build on our experiences with the Distribution System Plan (DSP).
- As part of our planning process, PGE sought input from non-traditional stakeholders, including individuals and organizations representing environmental justice communities. Our engagement strategy aligned multiple channels such as our Community Learning Labs, IRP Roundtables, relationship building and surveys.
- PGE sought to deploy and iterate accessible opportunities to gather feedback, including Mural activities and surveys.
- We are tracking the input we received through Mural and using it to inform planning and resource acquisition activities related to the CEP and IRP process.

[356] *See*, US Environmental Protection Agency Press Release, EPA Report Shows Disproportionate Impacts of Climate Change on Socially Vulnerable Populations in the United States, September 2, 2021, available at: https://www.epa.gov/newsreleases/epa-report-shows-disproportionate-impacts-climate-change-socially-vulnerable.
[357] See *In the Matter of Public Utility Commission of Oregon, House Bill 2021 Investigation into Clean Energy Plans,* Docket No. UM 2225, Order No. 22-390 (Oct 25, 2022), Appendix A at 36, available at: https://apps.puc.state.or.us/orders/2022ords/22-390.pdf.

14.1 Clean energy transition

14.1.1 Importance of equity and a human-centered approach

House Bill (HB) 2021 was the result of collaboration between utilities, environmental justice (EJ) groups, renewable energy and environmental advocates and other stakeholders. While much emphasis has been placed on the decarbonization objectives of the legislation, HB 2021 was also transformational for centering communities and equity in the clean energy transition. That equity lens is reflected in the work on Community-Based Renewable Energy (CBREs) and Community Benefits Indicators as described in **Chapter 7, Community benefits indicators and community-based renewable energy**. But it is also reflected in OPUC's provided guidance on community engagement strategies, as we discuss in this chapter.

PGE is committed to a future for Oregon in which all customers and communities can thrive. Investments in resources and grid modernization to meet our decarbonization targets can have a local, tangible and visible impact. As we plan for a clean energy transition, we are guided by our commitment to advancing social equity in the communities we serve. This begins with listening to and accounting for the diverse needs of all customers and communities and conducting our business in a way that promotes equitable access to clean energy solutions.

To support a human-centered approach to planning and prioritizing energy access, PGE works with communities and takes inspiration from best practices in community outreach and engagement. Our approach is intersectional, meaning issues such as gender, race, income and historical and geographic factors are considered when determining the disproportional impact that climate change, such as natural disasters, have on certain communities. Our approach also uses an equity lens, which allows for racial, gender and other inequities and how to address such disparities. This approach acknowledges how race, gender, people with disabilities, chronic health challenges and socioeconomic status will result in some members of our communities facing greater disparities.

Throughout this combined filing of PGE's CEP and IRP, we seek to present information in transparent, understandable and relatable ways.[358] We have worked, through our Community Learning Labs, to create content that can assist an introductory audience in understanding how PGE as a regulated utility engages in resource planning to meet energy needs reliably and affordably while complying with all regulatory requirements, including GHG emissions

[358] HB 2021 and subsequent OPUC Docket UM 2225 guidelines for utilities' Clean Energy Plans, emphasized the criticality of centering equity and community in planning for a clean energy transition.

targets. Further, Community Learning Labs provide additional context that customers and stakeholders need to understand, such as key terms, definitions and acronyms. This information enables our audiences to participate more fully in the public processes and dialogue surrounding our CEP and IRP. We also have created a website to provide transparency.[359]

14.2 Community engagement

Our vision is to lead the clean energy future together with our customers and communities. We are committed to cultivating and maintaining relationships with new and existing communities and community members, including those who have been historically excluded and underserved. In doing so, we work to consistently apply an equity and resiliency lens.[360] Community engagement is based on the belief that those impacted by a decision, program, project or service system need to be involved in the decision-making process.[361] This belief supports PGE's community outreach and engagement efforts of 'nothing about me without me.' This is PGE's guiding principle for conducting equitable community outreach and engagement practices. Additionally, we believe a clean energy future that is affordable and equitable requires a commitment to diversity, equity and inclusion (DEI) throughout our business.

Through our Distribution System Plan (DSP), PGE developed our human-centered approach as a starting point for our community outreach and engagement.[362] Our DSP Community Engagement Plan is informed by best practices, learnings and the recommendations of Unite Oregon, the Community Energy Project and the Coalition of Communities of Color based on their engagement in DSP Part 1.[363] We built on this work in our DSP Part 2 through

[359] Resource Planning website that provides access to CEP, IRP and DSP, available at: https://portlandgeneral.com/about/who-we-are/resource-planning.
[360] *In the Matter of Public Utility Commission of Oregon, House Bill 2021, Investigation into Clean Energy Plans*, Docket No. UM 2225, PGE's Updated Clean Energy Plan (CEP) Engagement Strategy (filed Aug 4, 2022), available at: https://edocs.puc.state.or.us/efdocs/HAH/um2225hah165755.pdf.
[361] A service system can be thought of as a portfolio of programs/services (*e.g.*, Income Qualified Bill Discount) and others provided to customers to meet a particular goal.
[362] PGE's Community Engagement Plan, available at: https://assets.ctfassets.net/416ywc1laqmd/Ade5oN7SaTG7jQRTGcPzt/576380f14d90a976469968517b187f95/DSP_2021_Report_Chapter3.pdf.
[363] Distribution Systems Planning (DSP) Community Engagement Best Practices and Recommendations Report developed by Unite Oregon, Community Energy Project and the Coalition of Communities of Color Community (July 19, 2021), the Engagement Plan, available at: https://assets.ctfassets.net/416ywc1laqmd/1wLNK2VjxZdnWiPSf5wvxf/f34e9939bd4cde85bb36d524b6a0177d/PGE_Community_Engagment_Report_7.20.21.pdf

Community-focused Workshops that concentrated on providing education on the technical aspects of the DSP into more relevant and translatable topics and content.

Our community outreach and engagement strategy for PGE's long-term planning processes builds on our experiences with the DSP Part 1 and Part 2 and is informed by three goals:

- Cultivate and maintain trusted and transparent relationships with community-based organizations (CBOs)/community-serving organizations (CSOs), EJ advocates and other community collaborators.
- Build awareness, inform and provide learning opportunities to communities.
- Encourage feedback that allows for continued transparency and the accessibility needed to improve collaboration and co-development of planning processes.

Additionally, PGE intends to use the three goals mentioned previously to achieve the following desired outcomes:

- Allow greater insights into the CEP and other planning processes needed to achieve decarbonization goals.
- Co-develop future community solutions and resiliency opportunities such as CBRE projects.
- Increase community participation, including Tribal and EJ communities.
- Demonstrate transparency and accountability.

We have engaged community groups through several channels in the development of this CEP. PGE hosted 30 Roundtable meetings and seven Community Learning Labs during the 2023 IRP development process. We made all meeting materials available on our CEP and IRP web pages and advertised public meeting dates there as well. We intend to continue our community engagement efforts beyond the filing of this plan, as our goals and desired outcomes are both near-term and long-term. For example, in this plan, we have a desired outcome for the co-development of community solutions and resiliency opportunities. This work will need to continue throughout 2023 and beyond as we have yet to begin procurement of these resources. We discuss those different engagement channels in the following sections.

14.2.1 Community Benefits Impact Advisory Committee

HB 2021 requires electric utilities that file a CEP to convene a Community Benefits and Impacts Advisory Group (CBIAG). PGE is establishing the CBIAG, a process that PGE embarked upon in 2022. The CBIAG will include representatives from EJ and low-income communities. Our CBIAG will be a forum in which HB 2021-mandated topics will be discussed.[364]

14.2.2 Tribal engagement

House Bill 2021 set forth a requirement for deeper and more meaningful engagement of Tribal and Indigenous communities. This bill included requirements for state agencies to consult with Tribes meaningfully, including consultation in the siting, permitting and construction of new energy facilities and new projects prior to actions that are likely to adversely impact designated archeological sites, or properties of traditional, cultural and religious importance.[365] HB 2021 also included a requirement that CBRE projects provide direct benefits to communities such as Tribes through direct ownership or a community benefits agreement or result in community benefits such as economic development. PGE continues to be committed to engaging with Tribes and Indigenous communities and demonstrates this commitment through our Strategic Tribal Engagement Plan (STEP). The STEP provides a framework for our teams to develop and maintain successful Tribal relationships by setting goals, identifying actions and implementing best practices to meet desired outcomes.

PGE acknowledges that the Tribal and Indigenous communities represent an important and multifaceted demographic and that their interests are intrinsically connected to our clean energy imperatives. Because of this, we partnered with Tribal entities on Federal grant applications to expand regional transmission capacity and open opportunities for renewable energy development on Tribal lands.

PGE and the Confederated Tribes of Warm Springs (CTWS) share ownership of Pelton Round Butte, a certified low-impact hydropower facility on the Deschutes River. This agreement is a shared testament to our close partnership and shared commitment to the Deschutes River Basin. In 2022, CTWS purchased an additional ownership interest in the Pelton Round Butte

[364] For information regarding HB 2021's CBIAG, see codified ORS 469A.425, available at: https://www.oregonlegislature.gov/bills_laws/ors/ors469A.html.
[365] ORS 469A.405(3).

hydroelectric project, increasing Tribes' share to 49.99 percent. PGE will continue to operate and purchase power generated from the Tribes' share of the project through 2040.

We also recognize the significance of collaboration with Tribes and Indigenous communities, which is why we have dedicated positions to support our Tribal relationships. Our Tribal Liaison is responsible for the overall program implementation and relationship management and serves as a company spokesperson at appropriate forums. Our Energy Equity Partner will work cross-functionally with our Tribal Liaison to engage Tribal and Indigenous communities.

14.2.3 Community learning labs

We designed our Community Learning Labs to foster an interactive experience for participants to learn about the CEP and other energy-related topics. This is in addition, and in contrast, to our monthly public IRP Roundtables, which describe the technical modeling and results of the IRP. Community Learning Labs are a public meeting space created for an introductory audience which includes, but is not limited to CBOs, CSOs, EJ advocates, other community collaborators and individuals. Community Learning Labs aim to build awareness, inform and collaborate with communities and stakeholders about specific CEP topics and seek feedback from participants. The Community Learning Labs provide opportunities to learn more about the CEP, and other relevant energy topics, including other PGE programs and planning processes like the IRP and DSP.

The Community Learning Lab process was originally used during DSP development to share related analysis and concepts with stakeholders with less experience participating in technical workshops. Through our DSP, we heard from our communities and stakeholders that creating an inclusive space for all our plans is their preference as it maximizes their time and helps connect the dots between planning efforts for them. We also heard from DSP attendees that they preferred shorter meetings, which resulted in scheduling Community Learning Labs for two hours versus three hours. Additionally, PowerPoint slides were used to present materials, recap previous meeting notes and introduce new topics.

To inform PGE's initial CEP and provide transparency and education to communities, we led seven Community Learning Labs from September 2022 through March 2023. In our first Community Learning Lab, we shared our approach, desired outcomes and process for community engagement. Throughout our CEP process, we explored several topics, such as CBREs, community benefits indicators (CBIs), non-wires solutions (NWS), resilience, our Preferred Portfolio and PGE's path to 2030 emissions targets.

We conduct all Community Learning Labs virtually via Zoom, as this was the preferred platform of attendees. To revisit materials asynchronously, we recorded all meetings per the

request of our attendees and uploaded them to our CEP website.[366] Also, we used Mural to collect anonymous feedback on presented information. In addition, we sent email notifications to the CEP distribution mailing list shortly after meetings.

Community Learning Labs demonstrate the evolution of PGE's philosophy of human-centered planning. Centering on community voices acknowledges our intention to understand the energy needs, desires, barriers and interests in clean energy planning, projects and related processes. We continue to demonstrate our commitment to being inclusive and equitable and to promote accessibility by creating a space for communities to participate and openly share information and feedback. We worked with communities to thoughtfully curate Learning Lab content and provide relevant learning opportunities to the community throughout the CEP development process. We intend to continue through 2023 and beyond to address additional topics. Refer to **Appendix L, Clean Energy Plan: Learning Labs community feedback** for additional information regarding the questions and comments we received through our Community Learning Labs. See **Section 14.3, Continuing community engagement** for examples of how we intend to apply stakeholder feedback to our planning activities.

14.2.3.1 Community Mural board exercises

Community Learning Labs sessions present topics in segments. After each section, PGE employed Mural exercises to receive feedback from participants. After presenting a topic segment, PGE sought community feedback by leading Mural exercises to review the material we presented. Each Mural exercise provided participants with timed questions focused on the important subject matter. To allow more time to collect additional feedback, we left Mural exercises open for two weeks after each Community Learning Lab session. For a list of questions conducted during the exercise, see **Appendix L, Clean Energy Plan: Learning Labs community feedback**.

Our Mural board exercises covered many topics, including but not limited to non-wire solutions, CBREs, CBIs and resilience. For example, through our Mural exercises, we introduced CBIs in a series of Community Learning Labs and focus groups and had participants rank which CBIs should be prioritized as part of our future CBI analysis. As a starting point for the Mural board exercises, we utilized the OPUC's UM 2225 Community Lens topics provided by the Energy Advocates. The Energy Advocates are a group of community, local government, climate, energy and renewable advocates that jointly filed comments within the OPUC's Docket UM 2225. The Energy Advocates Community Lens

[366] PGE's recorded Community Learning Labs, available at: https://portlandgeneral.com/about/who-we-are/resource-planning/clean-energy-planning.

topics comments are referenced in Attachment A of the Community Lens Straw Proposal in docket UM 2225).[367] The Energy Advocates' contributions helped start the conversation within our Community Learning Labs regarding how CBIs and Community Lens topics could be incorporated into our CEP.

14.2.3.2 CBI community engagement

PGE introduced CBIs in a series of Community Learning Labs and focus groups. In the Community Learning Labs and focus groups, we discussed our objectives for CBIs, our approach, our existing work on the DSP and its relationship to the CEP. PGE reviewed CBIs through a collaborative process with community members and EJ communities.[368] We conducted this process through our Community Learning Labs and other external engagement venues where we identified and prioritized CBIs with the community via the application, Mural. In our third Community Learning Lab, we asked participants to rank their top CBIs from the proposed list provided by the Energy Advocates. We had a total of fifteen participants and **Figure 112** illustrates the example results from the exercise.

[367] See OPUC Order No. 22-390, Appendix A at 65 (Attachment A Stakeholder CBI Proposal), available at: https://apps.puc.state.or.us/orders/2022ords/22-390.pdf.
Upcoming and past meeting materials, available at: https://portlandgeneral.com/about/who-we-are/resource-planning/integrated-resource-planning/irp-public-meetings.

Figure 112. Community Mural board example exercise

Which additional indicators should be prioritized going forward. Help us prioritize the Community Benefits Indicators.

Each participant has 6 stars to vote the next indicators to prioritize.

UM 2225 Stakeholder CBI Proposal (without associated measures)	Add a star to the indicators you recommend prioritizing
Tribal Benefits and Priorities	
Ecosystem/Non-Energy Benefits	
1. Protect fish and reduce the region's pressure on the Columbia River ecosystem	★★★★★★★ 7
2. Meaningful bilateral engagement between utilities and tribes on siting	★★★★★★★★ ★ ★ ★ ★ ★ 12
Energy Benefits	
1. Increased availability of electricity storage in Tribal and non-Tribal communities	★★★★ 4
2. Improve energy efficiency of housing stock in Tribal communities	★★ 2
3. Increased number of clean energy generation that powers Tribal communities	★ ★ ★ ★ 4
Larger Community Benefits and Priorities	
Energy Benefits	
1. Improve efficiency of housing stock in utility service territory, including low-income housing	★★★★★★★★★★★ 11
2. Low income and vulnerable communities have access to an increasing number of renewable or non-emitting distributed generation resources	★★★★★★★★★★★★ 12
Non-Energy Benefits	
1. Community Employment opportunities	★★★★★★★ 7
2. Health and Community well-being	★★★★★★ 6
3. Improved Public Health outcomes	★★★★ 4
4. Reduction in number of customers suffering from high energy burden	★★★★★★★★★★★★★★★ 15
5. Reduced barriers for program participation	★★ ★★★★★ ★ 9
Environment	
1. Reduction of GHG emissions	★★★★★★★★★★ 10
2. Reduced Pollution Burden and Pollution Exposure	★★★★★★★★ 8
3. Increase Neighborhood Safety	★★ 2
Energy Security	
1. Reduced Residential Disconnections	★★★★★★ 6
2. Improved access to reliable clean energy	★★★★★★★★ 8
Resilience	
1. Reduction in frequency and duration of blackouts or brownouts in target communities	★★★★★ 5
2. Reduction in energy and capacity need	★★★ 3
3. Reduction in recovery time and increase in survivability from outages	★★★★★★ 6

Although the Energy Advocates provided an extensive and thoughtful list of CBI recommendations, we reviewed CBIs with participants in our Community Learning Labs to identify additional CBIs and which CBIs are most important in the near-term. Through this work, we aim to begin defining and developing the CBIs in 2023. Based on the prioritization results from the community, we identified the top four CBIs to be prioritized as such:

- Reduction in the number of customers suffering from high energy burden
- Low-income and vulnerable communities have access to an increasing number of renewable or non-emitting distributed generation resources
- Meaningful bilateral engagement between utilities and tribes on siting
- Improve efficiency and housing stock in the utility service area, including lower-income housing in partnership with Energy Trust of Oregon (ETO)
- In **Section 7.1, Community benefits indicators**, we discuss the work we have done to begin prioritizing CBIs.

14.2.3.3 CBRE community engagement

PGE introduced CBREs in a series of Community Learning Labs and focus groups. In the Community Learning Labs and focus groups, we discussed our objectives for CBREs, our approach, our existing work on the DSP and its relationship to non-wire solutions. We also conducted Mural exercises on possible opportunities, approaches and the relationship between CBREs and CBIs.

Our goal with conducting community engagement on CBREs was to provide education on how we typically offer customer solutions. Today, CBRE resources within PGE's service area that bring community benefits are often supported by channels that tend to focus on individual technologies rather than stacking multiple technologies together to drive increased community benefits, which is allowed for under HB 2021's definition of CBREs. For example, PGE has a Smart Battery program that provides residential customers with home battery energy storage devices, while ETO has a Solar within Reach program that offers increased cash incentives for income-qualified households.

PGE plans to conduct continued community and stakeholder outreach and program design efforts that may yield better insights into the available potential of certain project types and their relative accessibility and feasibility. For example, in December of 2022, we shared a draft Community Supported Renewables concept with local governments, OPUC Staff and customers to socialize the changes we made that reflect feedback from our community outreach efforts. We continue to meet with our communities and revise the Community

Supported Renewables tariff framework, with an expected filing date in the third quarter of 2023.

PGE will also leverage our Community Learning Labs and other community and stakeholder engagement channels (e.g., DSP and Flexible Load Multi-year Plan (MYP)) to socialize and refine our approach for future CBRE potential study efforts for the next CEP. We are committed to working with our communities and community representatives to assess the need for more education and learning regarding CBRE and solicit ideas and input to inform future study efforts. We expect the evolution of how CBIs should be categorized and incorporated into future Community Lens potential study efforts will be guided by input from the CBIAG and continued discussions with our communities, stakeholders and Staff.

Lastly, PGE plans to build on the engagement and outreach conducted for this initial plan filing by conducting more targeted and structured research with market participants and developers working on CBRE-style projects. In our future assessment rounds, we aim to capture information that can help to characterize better market barriers, achievable potential and the costs and benefits associated with different CBRE resource types.

14.2.4 Roundtables

PGE manages CEP and IRP development through a collaborative, interactive process with an active public stakeholder group. All IRP meetings are open to the public and are generally hosted once a month. These roundtable meetings are technical forums to communicate, educate and seek feedback regarding PGE's IRP methodology, analysis and results. The IRP content presented during roundtables is complex, often requiring experience and knowledge of the energy industry. Additionally, stakeholders represent diverse perspectives and expertise from various communities in the state.

Our team strives to present comprehensive information in an approachable structure to encourage feedback and requests for clarification. As topics and attendance change, and in response to stakeholder feedback, PGE has adjusted how and when we take feedback during roundtable meetings. To provide transparency to the public, we publish these direct questions and responses, as permission allows, monthly when we post our meeting materials and video recordings. This allows all stakeholders to benefit from questions that other groups bring to us. Also, it prioritizes presenting complete information during our scheduled monthly roundtables. In addition, PGE continues to engage community-based organizations via the Community Learning Lab venue, as described previously.[369]

[369] CEP Community Learning Lab information available at: https://portlandgeneral.com/about/who-we-are/resource-planning/clean-energy-planning.

Before we started work on the 2023 IRP, we engaged stakeholders in a conversation about their organization's values and the IRP process.[370] Our stakeholders expressed what they value most: reliability and affordability in a decarbonized system, focusing on risk and uncertainty; clearly communicating what the IRP Action Plan means; and addressing and prioritizing the climate crisis in analysis.[371] We kept those values in mind throughout our process and built on the steps we took in the 2019 IRP to be responsive.

- We invited stakeholders to make specific portfolio requests during the 2023 IRP process and shared those requests at subsequent roundtable meetings.
- We shared draft information as the analysis unfolded.
- We invited stakeholders to submit informal comments throughout the process.
- We post video archives of each meeting and the meeting presentation on our website.
- We published comments received via the feedback form, starting in April 2022, and our responses each month to allow all participants to benefit from what others are asking about.
- We experimented with different approaches to facilitating the roundtables to encourage equitable participation among stakeholders.

The comments and suggestions shared with us are incorporated into our thinking and our final IRP, and the comments we received, plus our responses, are posted to our IRP webpage.[372]

14.2.5 Community surveys and feedback

To measure PGE's progress, we conducted six surveys after each Community Learning Lab, which were available on our CEP website. We left the survey open after each Community Learning Lab session to allow more time to collect additional feedback. The surveys allowed participants to provide feedback, evaluate Community Learning Labs and inform future content. We documented comments (via Mural, chat, and/or verbal) from Community Learning Labs and used them to uncover themes.

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[370] Portland General Electric Integrated Resource Planning, Roundtable 21-2, March 21, 2021, roundtable available at: https://assets.ctfassets.net/416ywc1laqmd/FYE0Gf8xbQgPZ4To88oZx/9f46ea7c1b93f55c1a0188160273880f/irp-roundtable-march-21-2.pdf.

[371] See Roundtable 21-2, March 21, 2021, slide 9, for more information about the values stakeholders expressed, available at: https://assets.ctfassets.net/416ywc1laqmd/FYE0Gf8xbQgPZ4To88oZx/9f46ea7c1b93f55c1a0188160273880f/irp-roundtable-march-21-2.pdf.

[372] Information available at: https://portlandgeneral.com/about/who-we-are/resource-planning/integrated-resource-planning.

During this process, we engaged a diverse set of participants comprised of CBOs, CSOs, EJ communities, government entities and individuals. As previously mentioned, we used several modalities to collect input and receive information from our community collaborators. This included surveys, Mural, chats, emails, informal interviews, focus groups and meetings with EJ advocates. Community Learning Lab evaluation surveys were kept anonymous to ensure more authentic responses. Additionally, we created a section for community members and/or customers to share their feedback on our website. See **Appendix L, Clean Energy Plan: Learning Labs community feedback** for additional information on our surveys.

We realized early that surveys could be one of many ways to gather information, as our response rates were lower than we had hoped. Due to this, we met with a handful of community advocates who collaborated with us on our DSP. We conducted informal interviews to increase the effectiveness of our approach to community engagement and Community Learning Labs. From this experience, we discovered that we need different engagement modes. Surveys were an excellent tool for collecting data however getting participants to take a survey was challenging. Therefore, we met with attendees outside the Community Learning Labs to obtain qualitative data. This informal environment allowed for an organic experience for the person to share feedback and helped build relationships with participants.

Refer to **Appendix L, Clean Energy Plan: Learning Labs community feedback** for additional information regarding the questions and comments we received through our Community Learning Labs. See **Section 14.3, Continuing community engagement** for examples of how we intend to apply stakeholder feedback to our planning activities.

14.2.6 Relationship building & informal engagement

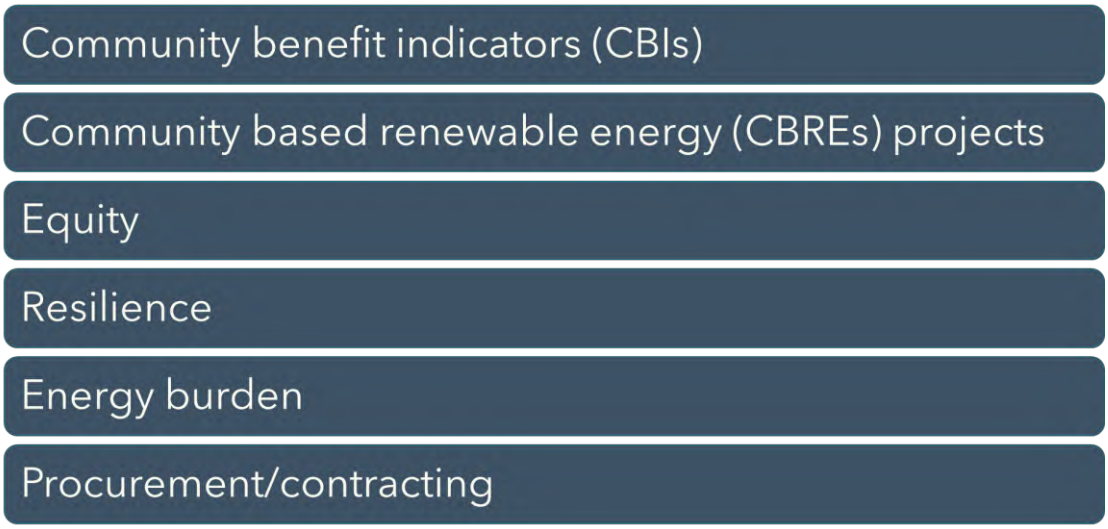
PGE conducted outreach to several organizations we have existing relationships through our DSP. These organizations represent climate, energy and community members. We worked to build new relationships for current and future plans, projects and programs and increase participation in our Community Learning Labs. Additionally, we used these forums to provide opportunities to roadshow specific topics covered in previous Community Learning Labs. Through this engagement channel, we heard from our communities and stakeholders how important it is for us to come to their locations/meetings to share information, as the capacity to participate in PGE public meetings is an ongoing challenge for most non-profits and community organizations.

We conducted follow-up, informal interviews with advocates and participants to capture more qualitative results and uncover gaps that need to be captured in surveys and Mural exercises. We interviewed several participants, who shared in-depth feedback on how they felt about the Community Learning Labs and our CEP generally. Some expressed how they

appreciated our efforts and included the community in the conversation regarding the CEP process. However, some shared that we need to make the information more digestible and relevant to attendees. We also learned through conversations with the community that they want more regular updates on how their contributions will be incorporated into our planning and implementation.

Overall, most interviewees were satisfied with our efforts and believed PGE was on the right path in addressing the CEP. Lastly, many expressed willingness to support PGE throughout Oregon's clean energy journey. Over several informal interviews, PGE engagement practitioners met with Energy Advocates and other community members. What we uncovered from our conversations were some trending topics/recurring themes. This included, but is not limited to, in no particular order: CBIs, CBRE projects, equity, resilience, energy burden and procurement and contracting. The qualitative data we collected through conversations enabled us to incorporate some of these topics/themes into our Community Learning Labs. Also, we understood how important it was to leverage these topics/themes to address the community's needs as we continue to use and evolve our human-centered planning model. **Figure 113** lists some of the trending topics captured from these meetings.

Figure 113. Trending community topics /themes



14.2.7 OPUC public meeting and advocate feedback

Over the past several years, PGE has heard from many of our communities how important we are to their daily lives. As an essential service provider, we have both an opportunity and an obligation to serve customers and communities. We are working to be more inclusive, broadening our perspective of community to establish trusted relationships with marginalized communities and communities of color and the organizations that represent them.

On December 15, 2022, in an OPUC Special Public Meeting for a Resiliency Technical Conference, we heard heartfelt testimonies from the EJ advocates and individuals.[373] We listened to the lived experiences and stories of what happens when an outage occurs and how it affects families and individuals. Every family is affected differently, such as or the decreased air quality within a home due to using woodfire stoves to keep warm. The range of impacts is far-reaching, even beyond the electric sector; however, as an essential service provider, we know we have a role to play. These testimonies reinforced the resiliency focus we seek to incorporate with our CEP and across the planning landscape, where possible. We understand the importance and urgency of this topic and plan on continuing the conversation in future Community Learning Labs. For additional information on our resilience efforts, see **Section 13.5, Programs and opportunities**.

14.2.8 Transparency and accessibility

Through Order 22-477, the OPUC provides draft rules for the CEPs stating the CEPs "must be written in language that is as clear and simple as possible, so that it may be understood by non-expert members of the public."[374] Additionally, through Order 22-446, the OPUC provide guidelines that "Staff, utilities and all interested stakeholders should collaboratively develop by February 1, 2023, an agreed upon approach to capturing additional standardized information and data related to their CEP and how they will make it publicly available in a similar fashion on their websites."

PGE is committed to ensuring customer data is safe and secure while exploring ways to make data more consumable for the broader audience, such as creating a dashboard to display non-sensitive data and information. PGE used several strategies to ensure transparency and

[373] Docket UM 2225, December 15, 2022, OPUC Special Public Meeting, HB 2021 Clean Energy Plans Resiliency Technical Conference, video recording, available at: https://oregonpuc.granicus.com/player/clip/1063?view_id=2&redirect=true&h=c546c1727b98130d5a6f2cdcbc3fc327.

[374] *In the Matter of Public Utility Commission of Oregon, House Bill 2021 Investigation into Clean Energy Plans,* Docket No. UM 2225, Order No. 22-477 (Dec 14, 2022), Appendix A at 11 (Staff's proposed draft Division 27 rule revision 860-027-0400(5)).

accessibility of our CEP. For this CEP, we focus on two areas of transparency and accessibility. The first is information related to our Community Learning Labs, and the other is a streamlined and dedicated website for our planning documents (e.g., CEP, IRP and DSP).

Within our Community Learning Labs, we heard that utilizing Microsoft Teams to host meetings is challenging for attendees because not all participants use Microsoft applications. Because of this, we conducted our Community Learning Labs virtually via Zoom, as this was the preferred meeting platform of attendees. We offered our Community Learning Labs the following resources: live transcripts and/or closed captions during meetings, a dedicated CEP website with access to previous Community Learning Lab materials and archived public meeting recordings. PGE also provided multiple ways to engage during meetings, such as verbal, chat feature, Mural Board, dedicated time for questions and answers (Q&A) and providing attendees with real-time feedback from our subject matter experts. Additionally, a CEP-shared mailbox was established for inquiries from the community, where they could communicate directly with the CEP team via email.

PGE established a dedicated website for all our resource plans (e.g., IRP, CEP and DSP) and provided access to information in new ways.[375] We publish our IRP data on our IRP website, including all material presented at IRP Roundtable meetings, associated Q&A responses and video recordings. Our website also provides additional materials and other relevant information regarding the CEP. We updated our indexing system based on participant feedback to allow easier navigation to specific topics of interest within the many hours of meeting recordings and slides presented.

PGE will also continue to evolve our practices to support any future agreed-upon approaches to capturing and reporting standardized information and data associated with the CEP.

14.2.9 Effectiveness of community engagement

Through Order 22-390, the OPUC provided guidance to utilities on how to report on the effectiveness of community engagement. This included:

- Information regarding community engagement in developing the plan, and
- Surveying participants who provided input on their experiences participating in the utility's process and their perspectives on how their input influenced the plan.

PGE recognizes the importance of building trusted relationships with the community. We are making concerted efforts to build relationships with new and different community

[375] Portland General Electric's Resource Planning, information available at: https://portlandgeneral.com/about/who-we-are/resource-planning.

collaborators to help build more awareness and bring community perspectives to PGE's plans, projects, programs and processes.

PGE measured the effectiveness of its community engagement through the following activities: facilitated Community Learning Labs, led focus groups, conducted evaluation surveys, held informal interviews with individuals and targeted outreach to communities that may be interested in learning about the CEP. Also, we continue with our learnings from the DSP to maintain space for our non-technical audience and established Community Learning Labs to socialize concepts and seek feedback on our approach to the following topics:

- Resilience
- CBIs
- CBRE and Non-wire Solutions

14.3 Continuing community engagement

Though PGE has a long history of robust long-term resource planning and of supporting renewable energy development, social equity and sustainability goals, our planning for specific emissions targets and the inclusion of CBREs and CBIs in those planning efforts is still relatively new. We expect this work will evolve and change over time; especially, as we learn from our efforts and continue to engage with our stakeholders and communities. Moving forward, we plan to host continual Community Learning Labs across our different planning platforms to maintain the dialogue with communities around the clean energy transition and to facilitate the connections between our clean energy planning, long-term resource and transmission planning, distribution system planning and program planning for transportation electrification, flexible loads and other priority initiatives.

Appendix

Appendix A. 2019 IRP Action Plan in review

Portland General Electric Company's (PGE) 2019 Integrated Resource Plan (IRP) was developed in consultation with the Oregon Public Utility Commission (OPUC or the Commission), and public stakeholders. Through the March 16, 2020, Commission decision and subsequent order issued May 6, 2020, the Commission acknowledged, with conditions and additional directives, the 2019 IRP. The 2019 IRP focused on three categories of actions: customer resource actions, renewable actions, and capacity actions. This appendix reviews the 2019 IRP with a focus on those three categories.

A.1 Customer resource actions

Action 1A: Seek to acquire all cost-effective energy efficiency, which is currently forecasted by the Energy Trust of Oregon (ETO) to be 157 MWa on a cumulative basis by 2025.[376]

Action 1B: Seek to acquire all cost-effective and reasonable distributed flexibility

The Commission acknowledged these actions with additional conditions and directives:[377]

> *Before the next IRP, PGE will work with Energy Trust and stakeholders to explore the potential for PGE's portfolio modeling to select incremental energy efficiency that is least cost, least risk, beyond Energy Trust's baseline forecast.*
>
> *Before the next IRP, PGE will work with Energy Trust to develop high and low energy efficiency forecasts that have internally consistent assumptions with the load scenarios.*
>
> *Before the next IRP, PGE and Energy Trust will conduct a workshop regarding data center load and energy efficiency measures and consider the adoption of the Northwest Power and Conservation Council energy efficiency capacity value modifiers. Staff may request a study if needed.*
>
> *In the next IRP, PGE is to report on trends of sales by customer class and DER installments for 2015 through 2019.*

[376] This forecast was current at the time of the 2019 IRP filing, July 19, 2019.
[377] In the matter of Portland General Electric Company, 2019 Integrated resource plan, Docket No. LC 73, Order No. 20-152, pg. 22, available at: https://apps.puc.state.or.us/orders/2020ords/20-152.pdf

PGE has acquired 27.4 MWa in 2020 and 24.1 MWa in 2021 of cost-effective energy efficiency. These acquisitions compose 33 percent of the targeted 5-year goal of 157 MWa by 2025 as discussed during the 2019 IRP.

PGE has acquired distributed flexibility of 231.31 MW.

- 92.7 MW DR Summer / 62.8 MW DR Winter (Customer Programs)
- 8.5 MW Battery (Nameplate MW) (Grid-Edge)
- 130.1 MW DSG (Grid-Edge)

We have incorporated and discuss how PGE has worked with ETO in accordance with the Commission conditions regarding our work with ETO within this IRP, including their process for forecasting Energy Efficiency (EE) for PGE's IRP based on the analytical model, results from the recent IRP forecast for data center EE potential, examples of EE savings from past data center projects, technologies employed, costs, incentives, kWh and kW demand savings, and lessons learned from the evaluations (see **Chapter 6, Resource needs**). PGE and ETO held a technical discussion with Staff and public stakeholders on data center load and energy efficiency measures on March 8, 2023. Staff did not request a study related to energy efficiency capacity value modifiers for inclusion in the 2023 IRP.

PGE reports on trends in sales by customer class in **Section 6.1, Load forecast**. PGE has reported on trends of sales by customer class and Distributed Energy Resources (DER) installments for 2015 through 2019 in the DSP part 1, Section 1.5 of Chapter 1.[378]

A.2 Renewable actions

Action 2: As modified in PGE's final comments,[379] PGE conducted an RFP seeking up to approximately 150 MWa of new, renewable resources that contribute to meeting PGE's capacity needs by the end of 2024.

PGE received regulatory approval to issue the 2021 All-Source RFP[380] in December 2021, with the RFP structure reflecting the intent of the 2019 IRP Action Plan and the significant resource need to be driven by the passage of House Bill 2021 after the acknowledgment of the 2019 IRP. PGE's 2021 RFP saw robust participation, with 110 bid options received,

[378] Distribution System Planning Part 1 available at: https://assets.ctfassets.net/416ywc1laqmd/ELNdf17zyQvQiU9k71pIX/683cd2f7b3098517068c4594100a1025/DSP_2021_Report_Chapter1.pdf
[379] PGE's Response to Staff Report at 4.
[380] In the matter of Portland General Electric Company, Request for Proposal and Independent Evaluator, Docket UM 2166, Order No. 21-460

representing over 11,500 MW of potential resources. PGE's final shortlist proposed for Commission acknowledgment included 13 unique projects representing 599 MWa of energy and 497 MW of capacity contribution (ELCC - effective load carrying capacity).[381]

The OPUC acknowledged PGE's final shortlist with conditions on July 15, 2022 (later memorialized in Order No. 22-315). In the Order, the Commission encouraged the Company to consider procuring approximately 250 MWa of renewable resources should procurement conditions warrant.[382] On October 25, 2022, PGE announced the procurement of the Clearwater Energy Center, a 311 MW portion of a wind facility located in Eastern Montana that will be constructed and operated by NextEra Energy Resources LLC. PGE continues negotiations with final shortlist bidders and will announce further actions upon execution of agreements.

PGE entered into three long-term solar contracts to support PGE's Green Future Impact (GFI) program. The 162 MW Pachwaywit Fields (also known as Montague Solar Facility) was announced in February 2020 and is expected to reach commercial operations by Fall of 2023 to support the GFI PGE supplied option phase I. Long-term agreements were also executed for the Bakeoven Solar Project and the Daybreak Solar Project to support GFI Customer supplied option for both phase I and phase II. The Daybreak and Bakeoven Solar Projects are expected to reach commercial operations by 2024.

A.3 Capacity actions[383]

Action 3A: Pursue cost-competitive agreements for existing capacity in the region.

Action 3B: Update the Commission and stakeholders on the status of PGE's bilateral negotiations and any resulting impacts on capacity needs.

PGE and Douglas County Public Utility District No.1 signed a five-year power purchase agreement to supply PGE customers with up to 160 MW of additional capacity from the Wells Hydroelectric Project on the Columbia River north of Wenatchee, Washington. The five-year agreement began in January 2021. PGE successfully executed a long-term contract for the

[381] PGE's final shortlist request for acknowledgment, filed May 5, 2022, available here: https://edocs.puc.state.or.us/efdocs/HAH/um2166hah151340.pdf

[382] Order No 22-315 at Page 5

[383] In the final comments, PGE proposes size limits that would apply across all procured resources. For capacity, PGE proposes not to exceed PGE's identified 2025 Reference Case capacity need of 697 MW for the combined capacity contribution of all procured resources; PGE will refine that maximum following an updated needs assessment prior to any RFP. For energy, PGE proposes to constrain energy additions across the capacity action and the renewable action to approximately 150 MWa to align with the 250 MWa portfolio screen and the expectation that bilateral procurement will result in some energy additions. The Commission acknowledged these actions with the additional condition that PGE must optimize its procurement approach.

output of Pelton Round Butte Project share owned by the Confederated Tribes of Warm Springs (CTWS). The fifteen-year agreement begins in 2025 and secures long-term off-take for 249 MW

As discussed in the OPUC Special Public Meeting on April 20, 2021, PGE procured both capacity and energy through a single all-source RFP. The final shortlist, acknowledged with conditions on July 14, 2022, and memorialized in Order No. 22-315, included 497 MW capacity contribution (ELCC) through five projects.

Our 2021 IRP Update,[384] filed January 29, 2021, updated the Commission on our use of bilateral negotiations to procure needed capacity. Pursuant to Order No. 21-129, we kept the Commission and Staff informed on negotiations and ultimately executed contracts totaling 234 MW of nameplate capacity using the bilateral procurement process.

A.4 2019 Action Plan checklist order no. 20-152

Table 77. Requirements and compliance from Order 20-152

Requirement	PGE compliance
Order 20-152 at 2 **We ask PGE to continue working to build a common understanding of its modeling terms and processes.**	PGE communicates IRP analysis through a series of public meetings and informal communication. The process is open to the public and building understanding with participants is a key objective of these meetings. See **Appendix C, 2023 IRP public meeting agendas**.
At 7	PGE complies with this requirement as part of IRP analysis and development. GFI resources are included in 2023 IRP modeling. See **Chapter 6, Resource needs**.

[384] In the matter of Portland General Electric Company, Integrated Resource Planning, Docket No. LC 73, Order No. 21-129 https://apps.puc.state.or.us/orders/2021ords/21-129.pdf

Requirement	PGE compliance
PGE does not exclude load associated with its voluntary green energy programs. PGE states that, because these programs have not yet started or are relatively new, the 2019 IRP considers potential customer participation in these programs in sensitivities. PGE states the sensitivities have little impact on PGE's needs. PGE states it will monitor participation in future IRPs and IRP Updates.	
At 8 **We also direct PGE to incorporate examination of customer program growth assumptions, including utility-offered programs and direct access, in its next IRP.**	PGE included the most up to date forecasts of customer programs, including both utility-offered programs and direct access; See **Section 3.1.7, Regulatory policy: Direct access** of **Chapter 3, Planning environment**.
At 8 **PGE stated it would continue to examine options related to Colstrip units 3 and 4 as additional information becomes available and will continue to prioritize cost impacts and risks to customers, reliability, and GHG emissions implications.**	PGE continues to perform this work as part of IRP analysis and development. See **Section 6.10, Need sensitivities** of **Chapter 6, Resource needs**.
At 9 **PGE communicated a sense of urgency to complete a Colstrip study and committed to complete the analysis by July 31, 2020. We consider this time frame reasonable, and because we expect that discussion of PGE's study will provide a framework for next steps, we do not establish a required schedule for updates at this time.**	Complete Colstrip enabling study.[385]

[385] The Colstrip enabling study is available at: https://assets.ctfassets.net/416ywc1laqmd/2AK9jf4GCmd1tyaLA8EODE/fb40144334f40fab7cc2e001676f1977/2020-colstrip-enabling-study.pdf

Requirement	PGE compliance
At 15 **We recognize Staff and stakeholders' growing frustration with PGE' s insistence on physical compliance modeling, and consider it important for PGE to proactively, consistently, and clearly show how portfolio results would change if PGE used an RPS compliance assumption that more closely matches its actual compliance strategy. This would involve maximizing use of unbundled RECs, which PGE has consistently done for RPS compliance, and should also involve using portfolio optimization tools to inform the least cost, least risk RPS compliance strategy.**	PGE discusses RPS requirements and our expectations of future REC generation in **Section 6.7, RPS need, Section 11.4.6, Targeted policy portfolios,** and **Section 11.5.2, Resulting RPS position**.
At 16 **We appreciate that PGE agreed to provide a climate adaptation strategy as an enabling analysis for the next IRP. This will be a helpful document to orient discussions around low water conditions, new flow patterns, and higher temperatures resulting from climate change.**	PGE worked with an external consultant to evaluate how climate adaptation should be incorporated into long-term utility modeling; see **Ext. Study-III, Climate adaptation.** PGE then took recommendations from this work and evaluated three climate adaption sensitivities; see **Section 6.9, Climate adaptation**.

Requirement	PGE compliance
At 16 **To advance a common understanding of whole portfolio decarbonization, we plan to hold a Commission workshop during the 2021 IRP development process to assess PGE's progress in developing and representing in its IRP a holistic decarbonization strategy, in the context of how other GHG policy drivers have developed. It is important that PGE consider its entire portfolio-including existing resource dispatch and transitions, new resource additions, and customer and demand-side resources-to deliver a full picture of how a least-cost, least-risk portfolio may also meet customer, company, community, and state decarbonization goals.**	Compliance with House Bill 2021 satisfies this request.
At 16-17 **We encourage PGE to consider portfolios that achieve PGE's proportionate share of the greenhouse gas emission reductions in Executive Order No. 20-04, as well as developing least-cost, least-risk strategies for assisting communities in its service territory that seek deeper, faster reductions.**	PGE included a robust discussion of the pace of decarbonization pathways going forward; See **Chapter 5, GHG emissions forecasting** and **Section 11.4.1, Decarbonization glidepath portfolios.**
At 17 **PGE explained the difficulties with transmission modeling, as transmission availability is constantly changing, and upgrade costs are not known until a specific project is studied. Nonetheless, PGE agreed to investigate how it can incorporate transmission availability of sub-regions to inform resource choices.**	PGE has incorporated transmission availability into portfolio modeling through data pulled from Bonneville Power Administration's (BPA) Transmission Study and Expansion Process (TSEP) and from an analysis of planned upgrades that may impact PGE's system. PGE describes transmission availability in **Chapter 9, Transmission** and its impact on portfolio selection in **Chapter 11, Portfolio analysis.**

Requirement	PGE compliance
At 19 **PGE's nontraditional screens were valuable here as a way to focus on key portfolio attributes, but in the future PGE should work closely with stakeholders to gain broad understanding of significant non-traditional screens before PGE uses a specific criterion as a constraint in modeling or as a screen in scoring.**	PGE complies with this requirement in **Chapter 11, Portfolio analysis,** and through discussion about scoring metrics and portfolio analysis assumptions at several IRP Roundtable meetings
At 19 **PGE should continue to work with Staff and stakeholders to explore how to model the cost and risk tradeoffs of energy additions in this environment.**	PGE complies with this requirement in **Chapter 11, Portfolio analysis** and through discussion about scoring metrics and portfolio analysis assumptions and results at several IRP Roundtable meetings
At 19 **...PGE also will need to consider future changes in energy markets, such as the potential transition to security-constrained, economic dispatch day-ahead markets, and how its resources will perform against market-wide clearing prices.**	PGE evaluates its resource portfolio against Western Power prices that are simulated in Aurora. This simulation approximates a Western economically dispatched day-ahead market. See **Appendix H, 2023 IRP modeling details** for more information on the Aurora model.
At 19 **...PGE will need to continue to evaluate and balance the tradeoffs between more certain near-term rate impacts and less certain long-term projected cost savings.**	**Chapter 11, Portfolio analysis** includes a substantial discussion about the trade-offs associated in resource planning between near- and -term costs.
At 19-20 **...PGE will also need to continue to support its proposal as it moves forward in changed circumstances, assessing whether the impacts of the COVID-19 pandemic are a material change to forecasts, needs, and its customers' tolerance for near-term rate pressure.**	PGE includes a substantial discussion of the effects of the pandemic as well as other developments in load forecasting in **Section 6.1, Load forecast** and **Appendix D, Load forecast methodology**.

Requirement	PGE compliance
At 21 **We agree that it is important to understand how PGE' s forecast would change with more aggressive energy efficiency measures, and also require PGE to explore the significant, cost-effective energy efficiency opportunities that may exist with data centers that are a significant component of industrial load growth.**	PGE evaluated the cost and risk trade-offs associated with the addition of more EE adoption in portfolio analysis; see **Section 8.2, Additional distributed energy resources** and **Chapter 11, Portfolio analysis** for more detail. With the Energy Trust of Oregon PGE presented on the topic of EE opportunities at data centers at the March 8th, 2023 round table.
At 22 **Before the next IRP, PGE will work with Energy Trust and stakeholders to explore the potential for PGE's portfolio modeling to select incremental energy efficiency that is least cost, least risk, beyond Energy Trust's baseline forecast.**	PGE evaluated the cost and risk trade-offs associated with the addition of more EE adoption in portfolio analysis; see **Section 8.2, Additional distributed energy resources** and **Chapter 11, Portfolio analysis** for more detail.
At 22 **Before the next IRP, PGE will work with Energy Trust to develop high and low energy efficiency forecasts that have internally consistent assumptions with the load scenarios.**	PGE included high and low EE forecasts developed by the ETO; see **Section 6.2, Distributed Energy Resource (DER) impact on load.** PGE then incorporated those forecasts into its Need Futures, described in **Section 6.6.1, Capacity under different Need Futures.**
At 22 **Before the next IRP, PGE and Energy Trust will conduct a workshop regarding data center load and energy efficiency measures and to consider adoption of the Northwest Power and Conservation Council energy efficiency capacity value modifiers. Staff may request a study if needed.**	This workshop was held **March 8, 2023**.

Requirement	PGE compliance
At 22 **In the next IRP, PGE is to report on trends of sales by customer class and DER installments for 2015 through 2019.**	PGE provided these data in the 2019 IRP Update Appendix B and Appendix C.[386]
At 23 **At the meeting, we also made special reference to the need for PGE to examine the implications of the COVID-19 public health crisis and corresponding economic disruption that were just emerging in Oregon as we made our acknowledgment decision in this case.**	PGE discussed these topics in **Chapter 6, Resource needs**.

[386] See pages 60-61: https://edocs.puc.state.or.us/efdocs/HAH/lc73hah13049.pdf

A.5 2021 IRP update order no. 21-129[387]

Requirement	PGE compliance
At 2 **Our deliberations involved two categories of interrelated issues, ELCC methodology and PGE's assumptions for new baseline solar resources. For methodology, PGE uses a single year of 2025, and we adopt Staff's recommendation for PGE to compute ELCC values by year and present the findings with its next IRP.**	We complied by estimating annual ELCCs by resource from the first main year of need through 2026, in line with the best practices provided by UM 2011. See **Appendix K, Tuned system ELCCs**.
At 4 **We find it is reasonable for PGE to complete its supply side resource study that is currently underway and update costs and operating characteristics of generation resources in the next IRP.**	PGE conducted its own evaluation of supply-side options; see **Appendix M, Supply-side options**.
At 1, 6 **Staff requests that PGE compute effective load carrying capability (ELCC) values by year and present the findings with its next IRP. Staff and stakeholders can use the findings to determine whether the impact of resource retirements and additions, and other changes in the load and resource balance, significantly change the ELCC values.**	Complete; see **Appendix K, Tuned system ELCCs**.

[387] In the matter of Portland General Electric Company, Integrated Resource Planning, Docket No. LC 73, Order No. 21-129, available at: https://apps.puc.state.or.us/orders/2021ords/21-129.pdf

Requirement	PGE compliance
At 1, 6 **Staff requests a workshop with PGE for the purpose of working with PGE before the 2021 IRP is filed to look at natural gas generation in the "high renewables buildout" price forecast and discuss whether gas resources would be likely to generate significantly less in that future, thus reducing market prices.**	PGE is not using a high-renewable buildout in this IRP.
At 4 **PGE should update its GEAR resources to include the recently approved customer-supplied option in Commission Order No. 21-053 in the base portfolio. The executed contract should not be treated as a sensitivity because it is now a reality.**	All GFI resources are included in the IRP planning models.

Appendix B. Compliance guidelines

The appendix catalogues, in tabular format, IRP requirements and lists where in the IRP the requirements are addressed.

B.1 Integrated Resource Plan guidelines

Table 78. Guideline 1: Substantive requirements

No.	Requirement	Compliance	Chapter
Guideline 1a	All resources must be evaluated on a consistent and comparable basis.	Resources are evaluated on a consistent and comparable basis as part of portfolio analysis work.	**Chapter 11, Portfolio analysis**
	All known resources for meeting the utility's load should be considered, including supply-side options which focus on the generation, purchase, and transmission of power – or gas purchases, transportation, and storage – and demand-side options which focus on conservation and demand response.	PGE's IRP includes known supply- and demand-side options that are expected to be available for meeting portfolio needs, including: wind, solar PV (photovoltaic), geothermal, biomass, standalone energy storage, solar PV with energy storage hybrid, energy efficiency, demand response, and incremental transmission resources. Supply-side resource options are tested with estimates of associated transmission wheeling costs.	**Chapter 8, Resource options** **Chapter 10, Resource economics** **Chapter 11, Portfolio analysis**

No.	Requirement	Compliance	Chapter
	Utilities should compare different resource fuel types, technologies, lead times, in-service dates, durations, and locations in portfolio risk modeling.	PGE's portfolio analysis compares resources across each of these factors.	**Chapter 8, Resource options** **Chapter 10, Resource economics** **Chapter 11, Portfolio analysis**
	Consistent assumptions and methods should be used for evaluation of all resources.	All resources are compared by using the same assumptions and methods.	**Chapter 11, Portfolio analysis**
	The after-tax marginal weighted-average cost of capital (WACC) should be used to discount all future resource costs.	Future costs are discounted at PGE's estimated long-term after-tax weighted-average cost of capital of 6.168% as a proxy for the long-term cost of capital.	**Appendix H, 2023 IRP modeling details**
Guideline 1b	Risk and uncertainty must be considered. At a minimum, utilities should address the following sources of risk and uncertainty:	PGE accounts for multiple sources of risk and uncertainty in the 2023 IRP.	**Chapter 11, Portfolio analysis**

No.	Requirement	Compliance	Chapter
	1. Electric utilities: load requirements, hydroelectric generation, plant forced outages, fuel prices, electricity prices, and costs to comply with any regulation of greenhouse gas emissions.	Portfolio modeling is conducted over multiple future conditions for technology costs, energy prices, hydroelectric conditions, load conditions, combining for 1134 different potential future conditions. Uncertainty in costs associated with compliance with Green House Gas (GHG) emissions reductions is accounted for through analysis of alternative GHG reduction glidepaths. Plant forced outages and other sources of uncertainty in reliability planning is accounted for in resource adequacy modeling in Sequoia.	**Chapter 8, Resource options** **Chapter 10, Resource economics** **Chapter 11, Portfolio analysis**
	2. Natural gas utilities: demand (peak, swing, and baseload), commodity supply and price, transportation availability and price, and costs to comply with any regulation of greenhouse gas emissions.	N/A for PGE	N/A for PGE

No.	Requirement	Compliance	Chapter
	Utilities should identify in their plans any additional sources of risk and uncertainty.	Refer to 1.b.1 for sources of uncertainty and risk considered by PGE in this IRP.	**Chapter 8, Resource options** **Chapter 10, Resource economics** **Chapter 11, Portfolio analysis**
Guideline 1c[388]	The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers.	Portfolio modeling used optimization to create portfolios that minimize expected costs. Portfolios were evaluated using traditional scoring metrics quantifying cost and risk as well as Portfolio Community benefits indicators (pCBIs) to select a Preferred Portfolio that performed well across all metrics.	**Chapter 11, Portfolio analysis, Table 92. Roadmap Acknowledgement**
	The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities should consider all costs with a reasonable likelihood of being included in rates over the long-term, which extends beyond the planning horizon and the life of the resource.	The planning horizon in portfolio analysis is 20 years (2024-2043). The costs and benefits associated with the resources considered extend over the entire expected lifetime. End effects are captured through levelized costs that account for the lifetime costs of resources procured within the planning horizon.	**Chapter 11, Portfolio analysis**

[388] In Order 23-060, OPUC waived Guideline 1c and directed utilities to follow revised planning guidance for the first IRP/CEP. PGE's approach to traditional cost and risk metrics is discussed below in **Appendix B.1**, with an additional description of our approach to new expectations described in the CEP RMA 1.5.a-h compliance section in **Appendix B.2**.

No.	Requirement	Compliance	Chapter
	Utilities should use present value of revenue requirement (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs for all long-lived resources such as power plants, gas storage facilities and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases.	Each of these sources of costs are accounted for in portfolio analysis, which uses Net Present Value Revenue Requirement (NPVRR) as the main cost metric. For all existing resources in PGE's portfolio, including long-lived resources and short-term contracts, all costs the Company would expect to incur to access and operate the resource (i.e., fuel cost and transportation, transmission, fixed cost recovery, contract costs, etc.) are accounted for throughout the lifetime of the resource in revenue requirement modeling.	**Chapter 11, Portfolio analysis**
	To address risk, the plan should include, at a minimum:		

No.	Requirement	Compliance	Chapter
	1. Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes.	Both variability and severity are used as risk metrics in portfolio analysis. Variability is measured using the semi-deviation of NPVRR across all futures, relative to the Reference Case. Severity is measured using the tail value at risk (TailVAR) at the 90Th percentile of NPVRR across all futures.	**Chapter 11, Portfolio analysis**
	2. Discussion of the proposed use and impact on costs and risks of physical and financial hedging.	Costs and risks of the resource additions which could provide a physical hedge against future wholesale market volatility are part of the considerations made during PGE's portfolio analysis. PGE does not consider any other long-term financial or physical hedging activities beyond those considerations.	**Chapter 11, Portfolio analysis**

No.	Requirement	Compliance	Chapter
	The utility should explain in its plan how its resource choices appropriately balance cost and risk.	Groups of portfolios are designed to target key sources of uncertainty around transmission, Distributed Energy Resources (DERs), Community-based Renewable Energy (CBRE), etc. Comparison of costs and risk metrics amongst portfolios within each group provides insights on these key topics to inform the design of the Preferred Portfolio. The portfolio analysis chapter describes the logic of how cost and risk are balanced.	**Chapter 11, Portfolio analysis**
Guideline 1d	The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.	All known federal and state energy policies in Oregon are reflected in the 2023 IRP, including the requirements of HB 2021.	**Chapter 11, Portfolio analysis**

Table 79. Guideline 2: Procedural requirements

	Requirement	Compliance	Chapter
Guideline 2a	The public, which includes other utilities, should be allowed significant involvement in the preparation of the IRP. Involvement includes opportunities to contribute information and ideas, as well as to receive information. Parties must have an opportunity to make relevant inquiries of the utility formulating the plan. Disputes about whether information requests are relevant or unreasonably burdensome, or whether a utility is being properly responsive, may be submitted to the Commission for resolution.	PGE began providing an opportunity for public involvement in the 2023 IRP starting in January 2020. Thirty-six public meetings, including seven Learning Labs, have been held seeking stakeholder feedback. PGE provides email, meetings, and a public feedback form as venues to submit additional or written input to IRP content.	**Appendix C, 2023 IRP public meeting agendas**

	Requirement	Compliance	Chapter
Guideline 2b	While confidential information must be protected, the utility should make public in its plan any non-confidential information that is relevant to its resource evaluation and action plan. Confidential information may be protected through the use of a protective order, through aggregation or shielding of data, or through any other mechanism approved by the Commission.	PGE provides non-confidential information used for portfolio evaluation and development of the Action Plan in the 2023 IRP.	All chapters and supporting appendices
Guideline 2c	The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Commission.	PGE filed a motion on November 22, 2022, requesting this guideline be waived. Guideline waived via Order No. 23-010[389], adopting Staff's recommendation at the 1/24/23 Public Meeting.	N/A for this filing

[389] Order No. 23-010. Request for waiver of Integrated Resource Plan guideline 2(c), available online: https://apps.puc.state.or.us/orders/2023ords/23-010.pdf

Table 80. Guideline 3: Plan filing, review, and updates

	Requirement	Compliance	Chapter
Guideline 3a	A utility must file an IRP within two years of its previous IRP acknowledgment order. If the utility does not intend to take any significant resource action for at least two years after its next IRP is due, the utility may request an extension of its filing date from the Commission.	PGE filed its last IRP on July 16, 2019. Commission acknowledged with conditions on March 15, 2020. PGE requested a waiver to delay the IRP filing date from March 2022 to March 2023 on October 15, 2021. The Commission approved the motion on November 18, 2021.	N/A for this filing
Guideline 3b	The utility must present the results of its filed plan to the Commission at a public meeting prior to the deadline for written public comment.	PGE will comply with this Guideline as arranged in the procedural schedule.	N/A for this filing
Guideline 3c	Commission staff and parties should complete their comments and recommendations within six months of IRP filing.	N/A for PGE	N/A for PGE

	Requirement	Compliance	Chapter
Guideline 3d	The Commission will consider comments and recommendations on a utility's plan at a public meeting before issuing an order on acknowledgment. The Commission may provide the utility an opportunity to revise the plan before issuing an acknowledgment order.	N/A for PGE	N/A for PGE
Guideline 3e	The Commission may provide direction to a utility regarding any additional analyses or actions that the utility should undertake in its next IRP.	N/A for PGE	N/A for PGE

	Requirement	Compliance	Chapter
Guideline 3f	Each utility must submit an annual update on its most recently acknowledged plan. The update is due on or before the acknowledgment order anniversary date. Once a utility anticipates a significant deviation from its acknowledged IRP, it must file an update with the Commission, unless the utility is within six months of filing its next IRP. The utility must summarize the update at a Commission public meeting. The utility may request acknowledgment of changes in proposed actions identified in an update.	N/A for this filing	N/A for this filing
Guideline 3g	Unless the utility requests acknowledgment of changes in proposed actions, the annual update is an informational filing that:		
	Describes what actions the utility has taken to implement the plan;	N/A for this filing	N/A for this filing

	Requirement	Compliance	Chapter
	Provides an assessment of what has changed since the acknowledgment order that affects the action plan, including changes in such factors as load, expiration of resource contracts, supply-side and demand-side resource acquisitions, resource costs, and transmission availability; and	N/A for this filing	N/A for this filing
	Justifies any deviations from the acknowledged action plan.	N/A for this filing	N/A for this filing

Table 81. Guideline 4: Plan components

	Requirement	Compliance	Chapter
	At a minimum, the plan must include the following elements:		
Guideline 4a	a. An explanation of how the utility met each of the substantive and procedural requirements;	The purpose of this table and **Appendix A** is to show compliance with this Guideline.	**Appendix A, 2019 IRP Action Plan in review** **Appendix B, Compliance guidelines**
Guideline 4b	b. Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions;	PGE has included low, reference, and high Need Futures that capture variance in load growth, DER adoption, and market capacity. Stochastic load risk is integrated within our assessment of capacity needs.	**Chapter 4, Futures and uncertainties** **Chapter 6, Resource needs**

	Requirement	Compliance	Chapter
Guideline 4c	For electric utilities, a determination of the levels of peaking capacity and energy capability expected for each year of the plan, given existing resources; identification of capacity and energy needed to bridge the gap between expected loads and resources; modeling of all existing transmission rights, as well as future transmission additions associated with the resource portfolios tested;	The 2023 IRP includes a capacity adequacy assessment, a flexibility-adequacy study, and an energy load resource balance calculation. These studies are used to inform portfolio analysis. The portfolio analysis chapter describes which resources would be the best option to fill the gaps between supply and demand while incorporating resource adequacy needs and transmission constraints.	**Chapter 11, Portfolio analysis** **Appendix F, Load resource balance**
Guideline 4d	For natural gas utilities, a determination of the peaking, swing, and base-load gas supply and associated transportation and storage expected for each year of the plan, given existing resources; and identification of gas supplies (peak, swing, and baseload), transportation, and storage needed to bridge the gap between expected loads and resources;	N/A for PGE	N/A for PGE

	Requirement	Compliance	Chapter
Guideline 4e	Identification and estimated costs of all supply-side and demand-side resource options, considering anticipated advances in technology;	Costs of future resource options are estimated from publicly available documents, including those produced by National Renewable Energy Laboratory (NREL) and Energy Information Administration (EIA). These future costs include anticipated advances in technology and manufacturing. PGE includes multiple future resource cost paths.	**Chapter 8, Resource options** **Chapter 10, Resource economics**
Guideline 4f	Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs;	PGE aims to have all portfolios meet a 2.4 LOLH (loss of load hours) target on a seasonal level. The portfolio model, ROSE-E, builds a least-cost system to this standard using available resources. We do sensitivities of how this buildout changes due to variations in demand or supply. We do not explore tradeoffs to system reliability at different levels (we do not study the cost/benefits of a less stringent adequacy standard).	**Chapter 6, Resource needs**

	Requirement	Compliance	Chapter
Guideline 4g	Identification of key assumptions about the future (e.g., fuel prices and environmental compliance costs) and alternative scenarios considered;	PGE has considered 351 potential futures across resource capacity needs, market electricity prices, and technology costs of new resources.	**Chapter 4, Futures and uncertainties** **Chapter 6, Resource needs**
Guideline 4h	Construction of a representative set of resource portfolios to test various operating characteristics, resource types, fuels, and sources, technologies, lead times, in-service dates, durations, and general locations – system-wide or delivered to a specific portion of the system;	PGE has constructed 40 portfolios across six categories to test various conditions and their impact on costs, risk, community benefit, decarbonization rate, and balance of short-term and long-term costs and benefits allocation.	**Chapter 11, Portfolio analysis**
Guideline 4i	Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties;	PGE conducted portfolio modeling over 1134 future scenarios, capturing a wide range of potential future conditions.	**Chapter 11, Portfolio analysis**

	Requirement	Compliance	Chapter
Guideline 4j	Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results;	PGE scored portfolios across both traditional scoring metrics designed to evaluate cost and risk and pCBIs which capture a range of community benefits. A Preferred Portfolio was developed that not only provides the best combination of cost and risk, but which also maximizes community benefits as required by the Clean Energy Plan.	**Chapter 11, Portfolio analysis**
Guideline 4k	Analysis of the uncertainties associated with each portfolio evaluated;	Uncertainties are accounted for in the construction of each portfolio, with portfolios designed to test key sources of uncertainty. Uncertainty is quantified in portfolio scoring through the evaluation of cost and risk metrics based on many potential future scenarios.	**Chapter 11, Portfolio analysis**
Guideline 4l	Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers;	PGE has developed a Preferred Portfolio that meets UM 2225 guidance of balancing costs, risks, and community benefits	**Chapter 11, Portfolio analysis**

	Requirement	Compliance	Chapter
Guideline 4m	Identification and explanation of any inconsistencies of the selected portfolio with any state and federal energy policies that may affect a utility's plan and any barriers to implementation;	PGE creates portfolios which comport with all state and federal energy policies, to the best of PGE's knowledge. PGE does not allow for the construction of portfolios that violate said policies. For example, we would not allow a portfolio that emits 2 million megatons (MMT) of GHG in 2030 when our state policy requires 1.62 or fewer MMT of CO2e emissions.	**Chapter 11, Portfolio analysis**
Guideline 4n	An action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, regardless of whether the activity was acknowledged in a previous IRP, with the key attributes of each resource specified as in portfolio testing.	PGE's Action Plan includes the resource actions PGE intends to take over the next two to four years, as reflected in the Preferred Portfolio. The Action Plan covers Customer Resource Actions, Renewable Actions, Capacity Actions, and Transmission Actions.	**Chapter 11, Portfolio analysis**

Table 82. Guideline 5: Transmission

	Requirement	Compliance	Chapter
Guideline 5	Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered. In addition, utilities should consider fuel transportation and electric transmission facilities as resource options, considering their value for making additional purchases and sales, accessing less costly resources in remote locations, acquiring alternative fuel supplies, and improving reliability.	PGE includes costs associated with fuel and electricity transmission, as appropriate, for new supply-side resources considered in portfolio analysis. See discussion in **Chapter 8, Resource options**, **Chapter 9**, **Transmission, Chapter 10, Resource economics**, and **Chapter 11, Portfolio analysis**.	**Chapter 8, Resource options** **Chapter 10, Resource economics**

Table 83. Guideline 6: Conservation

	Requirement	Compliance	Chapter
Guideline 6a	Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory.	PGE has incorporated Energy Trust's most recent long-term conservation potential study from May 2022. PGE coordinated with the Energy Trust to support the development of the EE forecast. Specifically, PGE provided information to the Energy Trust, which included load growth assumptions, cost of capital, and avoided cost inputs. PGE incorporated cost-effective energy efficiency as a given, within the resource Need Futures. PGE also incorporated additional energy efficiency that was deemed non-cost effective as a supply side resource.	**Chapter 6, Resource needs**

	Requirement	Compliance	Chapter
Guideline 6b	To the extent that a utility controls the level of funding for conservation programs in its service territory, the utility should include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets.	Since 2002, Energy Trust has been the independent, non-profit organization in charge of identifying the State's Energy Efficiency (EE) potential. PGE and other utilities fund such programs and work with the Energy Trust to implement EE measures. PGE maintains a long-term, productive relationship with the Energy Trust so that EE remains a top priority resource for PGE and the State.	N/A
Guideline 6c	To the extent that an outside party administers conservation programs in a utility's service territory at a level of funding that is beyond the utility's control, the utility should:		
	Determine the amount of conservation resources in the best cost/risk portfolio without regard to any limits on funding of conservation programs; and	The portfolios incorporate the results of the energy efficiency studies conducted by the Energy Trust which determine the amount of potential cost-effective energy efficiency without regard to any funding limits, except for the SB 838 funding constraints.	**Chapter 11, Portfolio analysis** **Chapter 12, Action Plan**

	Requirement	Compliance	Chapter
		Portfolios also incorporated additional energy efficiency that was deemed non-cost effective as a supply side resource available during portfolio analysis.	
	Identify the preferred portfolio and action plan consistent with the outside party's projection of conservation acquisition.	PGE's Preferred Portfolio and Action Plan include the Energy Trust's EE savings projection. Additionally, PGE has also evaluated additional EE to understand if and how the role of EE will evolve with the changing planning environment. These insights are also incorporated into the Preferred Portfolio and Action Plan. PGE continues to work collaboratively with Energy Trust to achieve sufficient funding for acquisition of all cost-effective and reasonable EE.	**Chapter 11, Portfolio analysis** **Chapter 12, Action Plan**

Table 84. Guideline 7: Demand response

	Requirement	Compliance	Chapter
Guideline 7	Plans should evaluate demand response resources, including voluntary rate programs, on par with other options for meeting energy, capacity, and transmission needs (for electric utilities) or gas supply and transportation needs (for natural gas utilities).	PGE has incorporated the most recent long-term demand response potential study from the Distribution System Plan Part 2[390] from August 2022. PGE incorporated cost-effective demand response as a given, within the resource Need Futures. PGE also incorporated additional demand response that was deemed non-cost effective as a supply side resource.	**Chapter 6, Resource needs** **Chapter 8, Resource options**

[390] PGE's Distribution System Plan Part 2, available at: https://apps.puc.state.or.us/edockets/edocs.asp?FileType=HAD&FileName=um2197had151613.pdf&DocketID=23043&numSequence=21

Table 85. Guideline 8: Environmental costs (order 08-339)

	Requirement	Compliance	Chapter
Guideline 8a	Base case and other compliance scenarios: The utility should construct a base-case scenario to reflect what it considers to be the most likely regulatory compliance future for carbon dioxide (CO_2), nitrogen oxides, sulfur oxides, and mercury emissions. The utility also should develop several compliance scenarios ranging from the present CO_2 regulatory level to the upper reaches of credible proposals by governing entities. Each compliance scenario should include a time profile of CO_2 compliance requirements. The utility should identify whether the basis of those requirements, or "costs," would be CO_2 taxes, a ban on certain types of resources, or CO_2 caps (with or without flexibility mechanisms such as allowance, credit trading, or a safety valve). The analysis should recognize significant and important upstream emissions that would likely	Portfolio analysis incorporates the requirements of House Bill 2021 and assumes full regulatory compliance for emissions for all resources. Specifically, we constructed a base-case scenario that includes carbon prices to dispatch for carbon emitting resources located in California, Washington, Alberta, and British Columbia to reflect the existing carbon emission legislation. In the base-case scenario, California and Washington carbon prices reference the California Energy Commission's (CEC) outlook of cap-and-trade legislation in California. The carbon prices for Alberta and British Columbia are equivalent to the locations' existing tax legislation. PGE also developed a high-carbon-case scenario in which the CEC's view of social cost is added as carbon prices for dispatchable carbon-emitting resources in California, Washington, and Oregon.	**Chapter 4, Futures and uncertainties**

	Requirement	Compliance	Chapter
	have a significant impact on its resource decisions. Each compliance scenario should maintain logical consistency, to the extent practicable, between the CO_2 regulatory requirements and other key inputs.	In this scenario, carbon emitting resources in the rest of the Western Electricity Coordinating Council (WECC) locations also have carbon prices forecasted by Wood Mackenzie's reference case. Finally, a low-case scenario is constructed with a low CEC carbon price outlook for California and Washington. The carbon prices for carbon emitting resources in British Columbia and Alberta are equivalent to their tax legislation. There are no carbon prices added to the rest of WECC carbon emitting resources in the low-case scenario.	
Guideline 8b	Testing alternative portfolios against the compliance scenarios: The utility should estimate, under each of the compliance scenarios, the present value of revenue requirement (PVRR) costs and risk measures, over at least 20 years, for a set of reasonable alternative portfolios from which the preferred portfolio is selected. The utility should incorporate end-effect	PGE tested a wide variety of portfolios across a large range of potential future conditions, including several alternative GHG emissions reductions glidepaths for complying with HB 2021 GHG emissions targets. Cost and risk metrics based on NPVRR are calculated on a 20-year analysis	**Chapter 11, Portfolio analysis**

	Requirement	Compliance	Chapter
	considerations in the analyses to allow for comparisons of portfolios containing resources with economic or physical lives that extend beyond the planning period. The utility should also modify projected lifetimes as necessary to be consistent with the compliance scenario under analysis. In addition, the utility should include, if material, sensitivity analyses on a range of reasonably possible regulatory futures for nitrogen oxides, sulfur oxides, and mercury to further inform the preferred portfolio selection.	time-horizon and compared across portfolios.	

	Requirement	Compliance	Chapter
Guideline 8c	Trigger point analysis: The utility should identify at least one CO_2 compliance "turning point" scenario which, if anticipated now, would lead to, or "trigger" the selection of a portfolio of resources that is substantially different from the preferred portfolio. The utility should develop a substitute portfolio appropriate for this trigger-point scenario and compare the substitute portfolio's expected cost and risk performance to that of the preferred portfolio – under the base case and each of the above CO_2 compliance scenarios. The utility should provide its assessment of whether a CO_2 regulatory future that is equally or more stringent than the identified trigger point will be mandated.	Since the Preferred Portfolio does not contain new resources that would emit GHG emissions, we do not anticipate more stringent CO_2 compliance requirements. We did, however, create three cases of carbon policy scenarios, described in Guideline 8a to anticipate a "trigger-point" scenario. For each of these carbon policy cases, base, high, and low case scenarios, they are paired with various permutation of WECC resource outlook, natural gas prices, and hydropower generation conditions. As a result, 27 price futures were created with base carbon policy case, 9 price futures were created with high carbon policy case, and 9 price futures were created with low carbon policy case. The inclusion of these price futures results in an increased variety of portfolio results. We also test the Preferred Portfolio under decarbonization scenarios, glidepaths, and other sensitivities.	N/A

	Requirement	Compliance	Chapter
Guideline 8d	Oregon compliance portfolio: If none of the above portfolios is consistent with Oregon energy policies (including the state goals for reducing greenhouse gas emissions) as those policies are applied to the utility, the utility should construct the best cost/risk portfolio that achieves that consistency, present its cost and risk parameters, and compare it to those of the preferred and alternative portfolios.	The portfolio analysis in the 2023 IRP is intended to be consistent with Oregon energy policies.	**Chapter 3, Planning environment**

Table 86. Guideline 9: Direct access loads

	Requirement	Compliance	Chapter
Guideline 9	An electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier.	Currently, PGE excludes estimated Direct Access load based on current customer elections and does not plan long-term resources to meet the potential demand from long-term opt-out customers. Nonetheless, PGE acts as the reliability provider for these customer loads.	**Chapter 4, Futures and uncertainties**

Table 87. Guideline 10: Multi-state utilities

	Requirement	Compliance	Chapter
Guideline 10	Multi-state utilities should plan their generation and transmission systems, or gas supply and delivery, on an integrated-system basis that achieves the best cost/risk portfolio for all their retail customers.	N/A for PGE	N/A for PGE

Table 88. Guideline 11: Reliability

	Requirement	Compliance	Chapter
Guideline 11	Electric utilities should analyze reliability within the risk modeling of the actual portfolios being considered. Loss of load probability expected, planning reserve margin, and expected and worst-case unserved energy should be determined by year for top-performing portfolios. Natural gas utilities should analyze, on an integrated basis, gas supply, transportation, and storage, along with demand-side resources, to reliably meet peak, swing, and base-load system requirements. Electric and natural gas utility plans should demonstrate that the utility's chosen portfolio achieves its stated reliability, cost, and risk objectives.	The 2023 IRP uses a stochastic modeling approach to resource adequacy. The model assembles 50,000 synthetic test weeks to evaluate capacity need under a range of conditions. For example, it may pair an extreme weather event, like the June 2021 heatwave, with different hydroelectric conditions, wind conditions, solar conditions, and forced outage rates. This allows for an examination of worst-case scenarios in the IRP. The IRP does not create portfolios that fail to meet the 2.4 LOLH reliability target. It does create numerous other portfolios that examine the cost and risk trade-offs between different resources.	**Chapter 6, Resource needs**

Table 89. Guideline 12: Distributed Generation

	Requirement	Compliance	Chapter
Guideline 12	Electric utilities should evaluate distributed generation technologies on par with other supply-side resources and should consider, and quantify where possible, the additional benefits of distributed generation.	PGE has incorporated the most recent long-term distributed solar and storage market adoption analysis from the Distribution System Plan Part 2[391] from August 2022.	**Chapter 8, Resource options** **Chapter 10, Resource economics** **Chapter 11, Portfolio analysis**

[391] PGE's Distribution System Plan Part 2, available at: https://downloads.ctfassets.net/416ywc1laqmd/2Fr2nVc4FKONetiVZ8aLWM/b209013acfedf1125ceb7ba2940bac71/DSP_Part_2_-_Full_report.pdf

Table 90. Guideline 13: Resource Acquisition

	Requirement	Compliance	Chapter
Guideline 13a	An electric utility should, in its IRP:		
	Identify its proposed acquisition strategy for each resource in its action plan.	PGE describes the proposed Action Plan, which includes discussion of strategies to acquire customer resources, renewable resources, and capacity resources.	**Chapter 12, Action Plan**
	Assess the advantages and disadvantages of owning a resource instead of purchasing power from another party.	PGE discusses the benefits and risks of owning a resource and power purchase agreements.	**Chapter 8, Resource options**
	Identify any Benchmark Resources it plans to consider in competitive bidding.	PGE is considering whether to submit a benchmark for inclusion in the renewable and/or capacity resource RFP proposed in the Action Plan. PGE will provide updated information about benchmark resources prior to issuing an RFP to market.	**Chapter 9, Transmission**
Guideline 13b	Natural gas utilities should either describe in the IRP their bidding practices for gas supply and transportation or provide a description of those practices following IRP acknowledgment.	N/A for PGE	N/A for PGE

Table 91. Flexible capacity resources (order no. 12-013)

	Requirement	Compliance	Chapter
1	Forecast the Demand for Flexible Capacity: The electric utilities shall forecast the balancing reserves needed at different time intervals (e.g., ramping needed within 5 minutes) to respond to variation in load and intermittent renewable generation over the 20-year planning period;	PGE contracted with Blue Marble Analytics to conduct a flexibility assessment using the GridPath model to determine the flexibility needs such as balancing reserves among others, to assess the system responsiveness to short time-scale variability of load and renewables as well as forecast errors.	**Chapter 6, Resource needs** **Chapter 10, Resource economics** **Ext. Study-IV, Flexibility study**
2	Forecast the Supply of Flexible Capacity: The electric utilities shall forecast the balancing reserves available at different time intervals (e.g., ramping available within 5 minutes) from existing generating resources over the 20-year planning period; and	The Blue Marble flexibility study described in requirement 1 for Order No. 12-013 includes the balancing reserve capability of existing generating resources.	**Chapter 6, Resource needs** **Ext. Study-IV, Flexibility study**

	Requirement	Compliance	Chapter
3	Evaluate Flexible Resources on a Consistent and Comparable Basis: In planning to fill any gap between the demand and supply of flexible capacity, the electric utilities shall evaluate all resource options, including the use of EVs, on a consistent and comparable basis.	The Blue Marble Analytics study included a valuation of the integration costs, and flexibility value of new resource additions.	**Chapter 6, Resource needs**

B.2 Clean Energy Plan guidance

Table 92, **Table 93**, and **Table 94** provide PGE's compliance report for the expectations adopted by the Commission in Orders 22-390 and 22-446. "RMA", "CLA" and "AI" refer to Roadmap Acknowledgement, Community Lens, and Analytical Improvements expectation areas, respectively. These tables cross-reference to the numbering rubric provided by Staff on February 24th ("OPUC No." column).

Table 92. Roadmap Acknowledgement

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
RMA1.1.a[392]	C.1, B.2	The first CEP should include analysis and annual goals over at least 20 years and CEP acknowledgment should focus on the annual goals in the first 2-4 years to align with the IRP analysis and acknowledgment horizons. Utilities may identify, and the Commission may use its discretion to acknowledge, resource actions outside of the Action Plan window.	The Clean Energy Plan (CEP) analysis covers the specified 20-year period and fully aligns with the IRP for the 2–4-year Action Plan. PGE has not proposed incremental actions specific to the CEP or outside of the Action Plan window.	**Chapter 1, Clean energy plan** **Chapter 11, Portfolio analysis** **Chapter 12, Action Plan**

[392] PGE has assigned numbers to the CEP expectations adopted by the Commission in Orders 22-390 and 22-446. "RMA", "CLA" and "AI" refer to Roadmap Acknowledgement, Community Lens, and Analytical Improvements expectations, respectively.

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
RMA1.2.a	C.2, C.2.a – C.2.i	For the first CEP, annual goals should be provided for all resource actions in each portfolio evaluated in the IRP. Resource actions include, at a minimum: clean energy resources, energy storage, energy efficiency, demand response, resource retirements, changes in system operations, transmission and other supporting infrastructure, and community-based renewable energy projects.	Annual goals for actions associated with all portfolios are provided for the full 20-year period.	**Chapter 11, Portfolio analysis** **Addendum: PGE CEP Data Template**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
RMA1.2.b	C.3	For the first CEP, annual goals for clean energy resources and storage should differentiate between system resources and resources that the utility expects to acquire through voluntary customer or community programs.	PGE's annual goals for clean energy and storage resources consider forecasts for voluntary program activity. Forecasts for voluntary supply-side programs (Green Future Initiative and Community Solar Program) are specifically differentiated from system clean energy resources in the 'Annual Goals for Actions' chart of PGE's supplemental data sheet. Forecasts for customer adoption of clean energy and storage are forecasted through AdopDER and are described in detail in PGE's Distribution System Plan.	**Chapter 11, Portfolio analysis** **Addendum: PGE CEP Data Template**
RMA1.3	C.4	The utility should report the following information on an annual basis in the first CEP for the Preferred Portfolio and a set of alternative IRP portfolios that test different paces of GHG reductions and different levels of community impacts:	--	--

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
RMA1.3.a	C.4.a	• Total greenhouse gas emissions associated with the portfolio based on the DEQ methodology, and broken out by individual fossil fuel resources, market purchases, and market sales.	PGE designed the Decarbonization Glidepath portfolios to compare outcomes associated with different paces of GHG reductions. Emissions data was provided for all portfolios, including several that tested the pace of GHG reductions through 2030.	**Section 11.4.1, Decarbonization glidepath portfolios** **Addendum: PGE CEP Data Template**
RMA1.3.b	N/A	• Normalized annual revenue requirement, calculated as the total revenue requirement for Oregon customers divided by the total retail sales in Oregon.	Expectation was removed by Order No. 22-390. See No. AI3.f-AI3.g.	--
RMA1.3.c	C.4.b	• A set of interim community impacts and benefits metrics that are developed in coordination with communities impacted by the plan, including environmental justice communities.	PGE designed the CBRE portfolios to compare outcomes associated with different levels of CBRE adoption, and associated community benefits. Informational CBIs developed in coordination with communities impacted by the plan, including environmental justice communities, were not used for portfolio evaluation consistent with definitions Order No. 22-390.	**Section 7.1, Community benefits indicators (CBIs)** **Section 11.4.3, Community-based renewable energy (CBRE) portfolios** **Addendum: PGE CEP Data Template**
RMA1.4.a	N/A	No near-term guidance.	--	--

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
RMA1.5.a	Not listed	PacifiCorp and PGE are directed to consider Staff's planning guidance for the first IRP/CEP.[393]	PGE has selected the Preferred Portfolio in consideration of the factors described below.	**Section 11.5, Preferred Portfolio**
RMA1.5.b	B.1	• The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers, the pace of greenhouse gas emissions reductions, and community impacts and benefits.	Metrics for costs, risks, emissions, and community benefits are evaluated in **Chapter 11, Portfolio analysis**. The answers to the most pressing questions in portfolio analysis helped inform the creation of the Preferred Portfolio, which best balances cost, risk, GHG reductions, and community impacts.	**Chapter 11, Portfolio analysis**
RMA1.5.c	Not listed	• The planning horizon…(see Guideline 1c, Order No. 07-002)	The planning horizon guidance was not modified by Order 23-060. Our compliance approach is described in **Appendix B.1**; see IRP Guideline 1c.	--
RMA1.5.d	Not listed	• Utilities should…(see Guideline 1c, Order No. 07-002)	Cost evaluation requirements was not modified by Order 23-060. Our compliance approach is described in **Appendix B.1**; See IRP Guideline 1c.	--
RMA1.5.e	Not listed	• To address risk…(see Guideline 1c, Order No. 07-002)	Risk evaluation requirements were not modified by Order 23-060. Our	--

[393] RMA 1.5a through 1.5h reflect revised language adopted via OPUC Order 23-060.

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
			compliance approach is described in **Appendix B.1**; See IRP Guideline 1c.	
RMA1.5.f	Not listed	• The pace of greenhouse gas emissions reductions should be evaluated, at a minimum, in a manner consistent with the methodology approved by the Oregon Department of Environmental Quality. In testing different paces of GHG emissions reductions, all portfolios should, at minimum, demonstrate year-over-year emissions reductions on an expected basis.	For this IRP, PGE updated the modeling approach used to forecast greenhouse gas emissions in order to align with the Department of Environmental Quality (DEQ) reporting methodology. The decarbonization glidepath portfolios were designed to compare outcomes associated with different paces of GHG reductions and ensured that each portfolio demonstrated year-over-year emissions.	**Chapter 5, GHG emissions forecasting** **Chapter 11, Portfolio analysis** **Addendum: PGE CEP Data Template**
RMA1.5.g	Not listed	• Community impacts and benefits of different portfolios of actions should be evaluated using available interim CBIs developed by the utilities using reasonable best efforts for use in the first CEP.	PGE evaluated community impacts and benefits with community partners within our Community Learning Labs. This work included developing community benefits indicators (CBIs) to be utilized within our IRP resource and portfolio analysis. Additionally, PGE also utilized the Oregon Public Utility Commission's (OPUC) Attachment A from Order 22-390, submitted by	**Section 7.1, Community benefits indicators (CBIs)** **Chapter 11, Portfolio analysis**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
			community as a starting point to prioritize future CBIs.	
RMA1.5.h	Not listed	• The utility should explain in its plan how its resource choices appropriately balance cost, risk, and the pace of greenhouse gas emissions reductions, and community impacts and benefits.	PGE included narrative to describe how the plan balances cost, risk, emissions, and community benefits in **Chapter 1, Chapter 12, and Chapter 13**.	**Chapter 1, Clean energy plan** **Chapter 11, Portfolio analysis** **Chapter 12, Action Plan**
RMA1.6.a	Not listed	To inform the Commission's acknowledgment decision, utilities should address the following in the first CEP:	--	--
RMA1.6.b	Not listed	• Whether the plan achieves the clean energy targets set forth in HB 2021:	All portfolios are expected on a planning basis to meet the HB 2021 emissions targets.	**Chapter 1, Clean energy plan** **Chapter 2 - Chapter 12**
RMA1.6.c	D.1	• The CEP should demonstrate how the IRP Preferred Portfolio achieves the emissions reductions targets set forth in HB 2021, with DEQ verification.	All portfolios are expected on a planning basis to meet the HB 2021 emissions targets.	**Chapter 5, GHG emissions forecasting** **Chapter 11, Portfolio analysis**
RMA1.6.d	A.2	• Consistency with the IRP:	CEP maintains all IRP assumptions and analysis to ensure full consistency.	--

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
RMA1.6.e	A.2	• The CEP should explain how it is consistent with the concurrently filed IRP in terms of assumptions, analysis, and planned actions.	All CEP and IRP analysis and Action Plan is interwoven, as described in **Chapter 1**. Analysis of emissions glidepaths to make continual progress toward 2030, 2035 and 2040 emissions targets for the CEP is an output of IRP modeling.	**Chapter 1, Clean energy plan**
RMA1.6.f	A.2	• To the extent that an analysis supporting the CEP was conducted in another docket (e.g., the IRP or DSP), the CEP should clearly reference that analysis. The utility should explain any updates or methodological changes to the referenced analysis and identify if the referenced analysis was or was not from a plan acknowledged by the Commission.	PGE has identified several sources of supporting analysis and information regarding the OPUC's CEP Community-Lens Topics such as equity analysis, resiliency, DER forecasting conducted within our DSP, tribal engagement, and reliability data within our Annual Report.	**Chapter 14, Community equity lens and engagement** **Chapter 13, Resilience**
RMA1.6.g	Not listed	• Effectiveness of community engagement:	As part of PGE's Community Learning Labs, we conducted surveys after each Learning Lab to gather feedback on the effectiveness of our community engagement.	**Section 14.2, Community engagement**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
RMA1.6.h	E.1, E.1.a – E.1.f	• The utility should report the following information regarding community engagement in developing the plan: what opportunities were provided for input and how was accessibility prioritized across those channels; which communities, including environmental justice communities and Tribal communities, did the utility consult with and how were those communities and their representatives identified; what input was received through each channel; how was input incorporated into the IRP/CEP; what input was not incorporated into the IRP/CEP and why was that input not incorporated; and what plans does the utility have for modifying the engagement strategy in future planning cycles.	PGE created multiple channels for community engagement. Our engagement strategies include virtual meetings for both technical and non-technical audiences, surveys, creating an accessible website and content, developing a CEP-specific email and individual one-on-one meetings with community. Community representation varied from individuals to community organizations. We collected feedback from community within our Community Learning Labs, which are iterative in nature. And, in the Looking Ahead section, we articulate how feedback will be incorporated into planning activities.	**Section 14.2, Community engagement** **Section 14.3, Continuing community engagement** **Appendix L, Clean Energy Plan: Learning Labs community feedback**
RMA1.6.i	E.2	• The utility should also survey participants who provided input on their experiences participating in the utility's process and their perspectives on how their input influenced the plan. Survey	As part of PGE's Community Learning Labs, we conducted surveys after each Learning Lab to gather feedback on the effectiveness of our community engagement.	**Appendix L, Clean Energy Plan: Learning Labs community feedback, Section L.2, Community input and feedback**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
		responses must be included with the plan.		**Chapter 14, Community equity lens and engagement, Section 14.1.1, Importance of equity and a human-centered approach**
RMA1.7.a	N/A	No near-term guidance at this time.	--	--
RMA1.8.a	L.2	The utility shall provide the following additional information in IRP Updates that follow CEP filings:	--	--
RMA1.8.b	L.2.a	• Progress to date relative to each annual goal for resource actions presented in the CEP. If resources have been secured, the utility should quantify the amount of each resource using the same units presented in the CEP.	N/A for this filing	N/A for this filing
RMA1.8.c	L.2.b, L.2.c	• Measured impacts across the same metrics that were presented in the CEP, including, at a minimum: greenhouse gas emissions intensity; total greenhouse gas emissions broken out by individual fossil fuel resources, market purchases, and market sales; average	N/A for this filing	N/A for this filing

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
		electric rates for Oregon customers; and the community impacts and benefits metrics.		
RMA1.8.d	L.2.d	• Any DEQ emissions reports filed since the CEP.	N/A for this filing	N/A for this filing

Table 93. Community lens analysis

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
CLA2.1.a	G.1	The first CEP should include a potential study (or studies) that identifies opportunities for community-based renewable energy projects (CBREs) developed in coordination with communities that are served by the utility, including environmental justice communities, and with input from stakeholders and Staff.	PGE utilized its DER Potential and Flexible Load Study and its associated AdopDER model to develop forecast analysis needed to inform CBRE targets for the Initial CEP. There will be three forecasts considered: community-scale solar, solar+battery, and small in-conduit hydropower.	**Section 7.2, Community-based renewable energy (CBRE)** **Section 8.3, Community-based renewable energy resources**
CLA2.1.b	G.4	The potential study should inform or directly identify annual acquisition targets (e.g., MW, MWh) for CBREs.	PGE utilized its DER Potential and Flexible Load Study and its associated AdopDER model to develop forecast analysis needed to inform our CBRE targets for the CEP Action Plan.	**Section 7.2, Community-based renewable energy (CBRE)** **Section 8.3, Community-based renewable energy resources**
CLA2.1.c	G.4	The potential study should inform or identify the acquisition targets that appropriately balance cost, risk, the pace of greenhouse gas emissions reductions, and community impacts and benefits.	Portfolio analysis is used to determine the acquisition targets that are reflected in the Preferred Portfolio.	**Section 7.2, Community-based renewable energy (CBRE)** **Chapter 11, Portfolio analysis**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
CLA2.1.d	Not listed	The potential study should measure community impacts and benefits based on interim community benefits indicators (CBI) established by the utility.	As part of PGE's DSP Part 2, we conducted a Community Targeting Assessment that developed a set of indices that assisted PGE understand the geospatial distribution of these parameters in our service area and identify affected and most vulnerable populations. Additionally, PGE utilized our DER Potential and Flexible Load Study to develop CBRE forecasts that already account for these parameters.	**Section 14.2, Community engagement** **Section 7.2, Community-based renewable energy (CBRE)**
CLA2.1.e	G.6	The first CEP should include a discussion of acquisition targets and actions that the utility will take in the action plan window to reach those targets e.g., utility procurements, utility run programs (existing and/or new), utility partnerships with other entities' programs, and projections for other customer and community-driven actions.	As part of PGE's Action Plan, we propose a potential Community RFP that will help us meet our CBRE targets. As part of this work, PGE will work with community and regional partners to further develop the RFP parameters such as scoring metrics.	**Section 7.2.3, Near-term approach within PGE's IRP** **Section 13.5, Programs and opportunities** **Chapter 12, Action Plan**, see **Sections 12.1.2, 12.2.2, 12.3**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
CLA2.1.f	G.7	If a specific project is proposed to meet some or all of the acquisition target, the utility should describe the timing, project status, status of any partnerships, and any other known critical path items involved.	PGE is not proposing a specific project needed to meet our CBRE targets. PGE has proposed conducting a potential Community RFP to meet our CBRE targets.	--
CLA2.1.g	G.8	The first CEP should include a narrative description of how the utility plans to further develop their CBRE potential study for the next CEP.	PGE intends to refine our CBRE approach through continued community engagement. We describe our plans in **Chapter 14, Community Equity Lens**.	**Section 7.2.9, New resources, programs and strategies** **Section 13.6, Looking ahead**
CLA2.1.h	G.9	The first CEP should report on the utility's plan to comply with the state's goal for community-based renewable energy projects provided in ORS 469A.210 and explain how the CBRE targets align with this strategy.	PGE's Action Plan includes steps PGE will take to acquire resources, including CBRE, that will advance our compliance toward the state's small-scale renewable target.	**Section 7.2, Community-based renewable energy**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
CLA2.2.a	G.2.b	Opportunities for CBRE actions, including distributed resources and their resiliency benefits, should be developed in coordination with communities that are served by the utility, including environmental justice communities, and with input from stakeholders and Staff.	PGE provided education and outreach on CBREs through its IRP Roundtables and CEP Learning Labs. The DER forecast, which our CBRE forecast was based on, was developed in partnership with communities, Staff, and stakeholders over the last two years through our IRP Roundtables and DSP Partnership Workshops. Additionally, PGE is not proposing a specific action needed to meet our CBRE targets. Rather, we proposed conducting a potential Community Request for Proposal (RFP) to meet our CBRE targets as well as the development of a future resiliency potential study needed to advance CBREs.	**Chapter 14, Community equity lens and engagement**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
CLA2.2.b	G.2.d	Plans for actions should reference DSP processes and engagement where appropriate.	PGE provided education and outreach on CBREs through its IRP Roundtables and CEP Learning Labs. The DER forecast, which our CBRE forecast was based on, was developed in partnership with communities, Staff, and stakeholders over the last two years through our IRP Roundtables and DSP Partnership Workshops.	**Section 14.2, Community engagement** **Section 13.5, Programs and opportunities**
CLA2.2.c	G.2.a	Opportunities that are considered for their community and/or resiliency benefits should also help facilitate greenhouse gas emissions reductions.	PGE evaluated four CBRE forecasts and as a result biogas was removed from our analysis due to the emitting nature of that resource. Our CBRE actions only will include opportunities that reduce GHG. PGE identified 155 MWs of CBRE potential by 2030.	**Sections 7.2, Community-based renewable energy (CBRE)** **Section 11.4.3, Community-based renewable energy (CBRE) portfolios**
CLA2.3.a	F.1	For the first CEP, the utility should develop interim community benefits indicators in coordination with communities served by the utility and with input from stakeholders and Staff.	PGE's CBI approach was based on suggestions provided by the Energy Advocates coalition. PGE worked with community advocates via our Learning Lab process to identify additional indicators and prioritize our approach.	**Chapter 14, Community equity lens and engagement** **Sections 7.1, Community benefits indicators (CBIs)**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
				Appendix L, Clean Energy Plan: Learning Labs community feedback
CLA2.3.b	F.2	At a minimum, the utilities should use quantifiable and measurable interim CBIs in development of the first CEP/IRP that together address the following CBI topic areas:	PGE's CBIs together address each topic area identified. The approach to CBIs within our IRP is to utilize a 10% adder for our Resource CBI pathway and a scoring methodology for our Portfolio CBI pathway.	**Section 7.1, Community benefits indicators (CBIs)**
CLA2.3.c	F.2.a	• Resilience (system and community)	PGE's iCBI-3 addresses improved grid resilience via two metrics that track customer outages and customer access to backup power in EJ communities.	**Section 7.1.6, Informational community benefits indicators**
CLA2.3.d	F.2.b	• Health and community well-being	PGE's Informational CBI-1 (iCBI) and iCBI-6 address health and community well-being via four metrics that track participation in clean energy programs and energy efficiency achievement in environmental justice (EJ) communities.	**Section 7.1.6, Informational community benefits indicators**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
CLA2.3.e	F.2.c	• Environmental impacts	PGE's iCBI-5 addresses environmental impacts with a metric that tracks reduction in GHG emissions.	**Section 7.1.6, Informational community benefits indicators**
CLA2.3.f	F.2.d	• Energy Equity (distributional and intergenerational equity), and	PGE's iCBI-1 and iCBI-6 address energy equity via four metrics that track participation in clean energy programs and energy efficiency achievement in EJ communities.	**Section 7.1.6, Informational community benefits indicators**
CLA2.3.g	F.2.e	• Economic impacts	PGE's iCBI-2 and iCBI-4 address economic impacts via five metrics that track energy affordability and increased access to jobs by members of EJ communities.	**Section 7.1.6, Informational community benefits indicators**
CLA2.3.h	F.3	At a minimum, the interim CBIs should include at least one metric of each of the following categories:	PGE's CBI approach addresses each of the three CBI categories.	**Section 7.1, Community benefits indicators (CBIs)**
CLA2.3.i	F.3.a	• Informational CBIs, which may or may not directly inform portfolio scoring in the IRP;	PGE developed Informational CBIs or iCBIs, providing transparency into important topics for communities.	**Section 7.1.6, Informational community benefits indicators**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
				Section 11.6, Informational community benefits indicators
CLA2.3.j	F.3.b	• CBRE-focused CBIs, which are used to inform and track progress on CBRE actions and should be reflected in the CBRE potential study and in IRP portfolio scoring; and	PGE developed a Resource CBI (rCBI) to inform and track progress on CBRE actions. Our rCBI methodology applies a credit of 10% to the CBRE fixed cost for all three of the CBREs we evaluated, making them relatively more competitive compared to other supply side options. This methodology allows an approximation of the value of community benefits to be reflected in the CBRE potential study and in IRP portfolio scoring.	**Section 7.1.3, Resource community benefits indicators** **Section 10.9, Resource community benefits indicators**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
CLA2.3.k	F.3.c	• Portfolio CBIs, which address the impacts of the utility's portfolio on communities, may or may not be tied to CBREs, and should be reflected in IRP portfolio scoring.	PGE developed a Portfolio CBI or pCBI to address the impacts of the utility's portfolio on communities. Portfolio CBIs are meant to adjust portfolio analysis scoring and are calculated for all portfolios evaluated. PGE introduces pCBI as a catch-all for all supplemental benefits that may come from the addition of CBREs. This metric (1 MW of CBRE =1 unit of Community Benefits) reflects the unquantifiable portfolio benefits associated with the CBRE additions.	**Section 7.1.4, Portfolio community benefits indicators** **Section 11.2, Portfolio scoring**
CLA2.3.l	F.4	The utility should explain how their interim CBIs address each of the five topic areas and note which of the three listed CBI categories each metric falls within. The utility should also explain their plans for further developing CBIs for the next CEP.	We developed three pathways for CBIs within our IRP. PGE will continue to work with community to identify CBIs that are of the highest priority for our communities. We will then work to identify which of those CBIs can be quantified and are measurable.	**Chapter 14, Community equity lens and engagement** **Section 7.1, Community benefits indicators (CBIs)** **Section 7.2.10, Further actions and considerations**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
CLA2.4.a	G.5	For the first CEP, the utility should incorporate the CBRE acquisition targets into IRP portfolio modeling in a manner that accounts for their expected costs and their expected impacts on the IRP resource portfolio performance, including impacts to resource dispatch and fuel burn, portfolio emissions, resource adequacy needs, and resource additions.	Three CBRE proxy resources were developed for IRP portfolio modeling with specific cost and performance attributes. For portfolio modeling, a 10% cost reduction was applied via our rCBI methodology to account for unquantified community benefits. Portfolio analysis incorporated the costs and system benefits associated with the proxy CBRE resources.	**Chapter 11, Portfolio analysis**
CLA2.4.b	G.3	If system-wide benefits exist for a potential CBRE, the utility should quantify those benefits in a manner consistent with the IRP when evaluating the opportunity for inclusion in the first CEP. System-wide benefits are not limited to, but may include: resource adequacy contributions, energy value, avoided GHG emissions, and avoided transmission.	Since the three CBRE proxy resources were included in IRP portfolio modeling, treatment of all system-wide benefits are consistent with the IRP.	**Chapter 11, Portfolio analysis**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
CLA2.5.a	K.1	The first CEP must include narrative which describes its resiliency-related analysis, including at minimum:	PGE developed a resilience-specific chapter for this initial CEP. This chapter provides PGE's approach to resilience-related analysis as outlined by the OPUC's UM 2225 resiliency-specific guidelines. Additionally, it includes a discussion of how PGE coordinated with our partners, identifies resilience risks and opportunities, as well as key resilience-related programs and opportunities we will prioritize to support CBRE.	**Chapter 13, Resilience**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
CLA2.5.b	K.1.a	How it was developed in coordination communities that are served by the utility, including environmental justice communities, and with input from stakeholders and Staff;	PGE created multiple channels for community engagement. Our engagement strategies included virtual meetings for both technical and non-technical audiences, surveys, creating an accessible website and content, developing a CEP-specific email and individual one-on-one meetings with community. Community representation varied from individuals to community organizations. We collected feedback from community within our Community Learning Labs, which are iterative in nature.	**Section 14.2, Community engagement, Chapter 13, Resilience**
CLA2.5.c	K.1.b	How resiliency risks were considered examined and weighted;	PGE has taken multiple steps toward evaluating risks related to climate change and natural disasters. We utilized existing risk assessment analysis regarding system and customer resilience; including energy equity work conducted through our Distribution System Plan (DSP) and Wildfire Mitigation Plan (WMP).	**Section 13.2, Evaluating resilience risks**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
CLA2.5.d	K.1.c	How resiliency opportunities were identified, measured, and weighted; and	During PGE's community engagement process we discussed potential resilience analysis, approaches, programs, and opportunities. PGE provided education on several planned and active initiatives that serve to create or enable a more resilient grid and to empower customer resilience.	**Section 13.5, Programs and opportunities**
CLA2.5.e	K.1.d	The key resiliency-related actions the utility will prioritize in the action plan window to support its CBRE acquisition targets.	As part of PGE's Action Plan, we propose a potential Community RFP that will help us meet our CBRE targets including solar+storage microgrid projects that advance community resilience. Additionally, we will work with community to develop a future resiliency potential study needed to advance CBREs.	**Chapter 12, Action Plan** **Section 12.1.2, Community-based renewable energy additions** **Section 12.2.2, CBRE action**
CLA2.5.f	Not listed	When evaluating resiliency risks for the first CEP and associated IRP, the utility should at minimum:	--	--

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
CLA2.5.g	K.2	Account for system and community resilience.	We utilized existing risk assessment analysis regarding system and customer resilience; including an enterprise-wide risk assessment, transmission and distribution asset assessment, and a community assessment.	**Section 13.2, Evaluating resilience risks** **Section 13.3, Zone of tolerance**
CLA2.5.h	K.3	Identify risks that have been identified in other planning processes already as well as gaps in system and community resilience not filled by other planning activities, such as DSP and WPP.	We utilized existing risk assessment analysis regarding system and customer resilience; including an enterprise-wide risk assessment, transmission and distribution asset assessment, and a community assessment.	**Section 13.3, Zone of tolerance** **Section 13.4, Historical reliability data**
CLA2.5.i	K.4	Consider the zone of tolerance for communities/populations within the service area.	PGE discussed "zone of tolerance" within its **Resilience Chapter**. This section speaks to existing work such as our DSP, Biden's Justice40 Initiative, Medical Certification Programs and Critical Customer Program.	**Section 13.3, Zone of tolerance**
CLA2.5.j	K.5, K.5.a	Rely on measurable historical reliability performance measures that reflect: all outages (planned, major event, or underlying);		**Section 13.4, Historical reliability data**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
CLA2.5.k	K.5.b	The primary initiating event for each major event the utility analyzed;	PGE utilizes historical reliability performance data as an input to evaluating reliability and resiliency risk on the system. The data informs the failure probability assumptions in the economic risk models for asset-caused and geographic-caused failures and is used to develop potential mitigation solutions.	
CLA2.5.l	K.5.c	The top causes for each day during which a major event occurred;		
CLA2.5.m	K.5.d	The numbers of customers out and the restoration performance for their supply;		
CLA2.5.n	K.5.e	The estimated costs to the utility to recover from the major event;		
CLA2.5.o	K.5.f	The estimated unserved energy during the period of a major event;		
CLA2.5.p	K.5.g	The estimated impacts to the customers;		
CLA2.5.q	k.5.h	The demographics of the community, including classification of energy equity or other social or environmental justice measures.	PGE utilized socioeconomics and demographic data within our DSP Part 2 as part of our CEP.	**Section 13.4, Historical reliability data**
CLA2.5.r	G.2	While evaluating opportunities and developing actions to achieve CBRE acquisition targets, the utilities should reflect a few minimum expectations:	--	--

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
CLA2.5.s	G.2.a	Focus on actions that help facilitate emissions reductions (e.g., generation, storage, demand-side actions). However:	PGE's Action Plan includes a potential Community RFP that will help us meet our CBRE targets, which will target resource actions that provide both emissions reductions and community benefits.	**Section 7.2, Community-based renewable energy (CBRE)** **Section 12.2.2, CBRE action**
CLA2.5.t	Not listed	The utility may include, for general understanding, if there are other actions, such as undergrounding lines connected to a microgrid that need to be included in the costs and benefits of a CBRE.	During PGE's community engagement process we discussed potential resiliency analysis, approaches, programs, and opportunities. PGE provided education on several planned and active initiatives that serve to create or enable a more resilient grid and to empower customer resilience. This work is included for general understanding only and is not directly included in the Action Plan.	**Section 13.5, Programs and opportunities**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
CLA2.5.u	Not listed	The utility may include supplemental discussion of other actions the company is taking to further enhance the resiliency of its system and communities (such as situational awareness investments or helping customers access portable back up generation). This discussion would be for context only and if the actions are not facilitating emissions reductions, they should not be considered actions for the CEP.	During PGE's community engagement process we discussed potential resiliency analysis, approaches, programs, and opportunities. PGE provided education on several planned and active initiatives that serve to create or enable a more resilient grid and to empower customer resilience. This work is included for general understanding only and is not directly included in the Action Plan.	**Section 13.5, Programs and opportunities**
CLA2.5.v	G.2.c	Consider opportunities to work with local communities on local resiliency planning.	PGE has several planned and active initiatives that serve to create or enable a more resilient grid and to empower customer resilience. Additionally, we are exploring ideas to partner with local community and local resiliency planners such as Community Resiliency Hubs.	**Section 7.2.10, Further actions and considerations** **Section 13.5, Programs and opportunities**
CLA2.5.w	G.2.d	Consider and clearly differentiate actions that are related to other plans, such as DSP and WPP analysis, and those that are newly identified.	PGE provided an update on its resilience efforts within its Resilience chapter. This includes actions proposed within the DSP such as updating our Value of Service Study.	**Section 13.5, Programs and opportunities**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
CLA2.5.x	G.7	If proposing a specific action, describe the cost, timing for delivery and implementation into utility operations.	PGE is not proposing a specific action within our CEP; however, PGE will work with community on a future resilience-specific potential study needed to advance CBREs.	**Section 13.5, Resilience opportunities**

Table 94. Analytical Improvements

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
AI1.a	H.5	Staff recommends that PAC and PGE include narrative, supported by quantitative analysis where possible, answers to the following long-term decarbonization questions within the first CEP:	--	--

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
AI1.b	H.5.a	1. What low regrets near term actions does the utility expect to perform relatively well, if implemented, regardless of future uncertainties in technology, demand, and regional developments?	PGE's Action Plan describes the low regrets actions which are appropriate to take in the next 2-4 years. All paths that achieve an 80% emissions reduction on PGE's system involve a significant buildout of non-emitting energy storage and renewables. In terms of transmission, we also consider South of Alston congestion relief and upgrades to the Bethel-Round Butte line as "no-regrets." We anticipate negotiating contract renewals to maintain contracted non-emitting resources in our portfolio. Additional details are available in **Chapter 1, Clean energy plan**.	**Section 1.6, High-level opportunities, potential barriers, critical dependencies** **Chapter 12, Action Plan**
AI1.c	H.5.b	2. What near term actions that the utility considered might have large negative long-term consequences (in terms of cost, risk, GHG emissions, or community impacts or benefits) under one or more future technology, demand, or regional development scenarios?	In the near term, the risks of large negative long-term consequences for our compliance path relate to anything that delays or prevents our ability to execute on the Action Plan. Additional details are available in **Chapter 1, Clean energy plan**.	**Section 1.6, High-level opportunities, potential barriers, critical dependencies**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
AI1.d	H.5.c	3. What are the critical junctures at which the utility's plan would materially change and what indicators will the utility use to identify whether those junctures are approaching?	PGE will be tracking closely the pace of acquisition of non-emitting energy and capacity. If we cannot maintain reliability or the pace of constant yearly acquisition of resources and capacity, we will need to adjust our approach to overcome delays or adjust timelines accordingly, if the variables causing the delay are beyond our control. At the same time, if new transmission options on- and off-system do not materialize, we will likely not be able to access the resources our system needs to decarbonize and maintain reliability. Additional details are available in **Chapter 1, Clean energy plan**.	**Section 1.6, High-level opportunities, potential barriers, critical dependencies**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
AI1.e	H.5.d	4. What are the critical dependencies for the utility to successfully execute its long-term plan? What are the critical dependencies for the utility's plan to achieve the desired outcomes in terms of cost, risk, GHG emissions, and community impacts or benefits? What might be the implications of one or more of those critical dependencies failing?	Large quantities of non-emitting resources must be available on the market, and at the lower price points we forecasted for them. New transmission is needed to gain access to off-system resources, or we risk the reliability of the system. As we near the 2040 target and a zero emissions requirement, new technologies that can replicate thermal generation capacity, such as advanced nuclear, hydrogen, or carbon capture and storage will be needed across the region to support decarbonization and resource adequacy. Additional details are available in **Chapter 1, Clean energy plan**.	**Section 1.6, High-level opportunities, potential barriers, critical dependencies**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
AI1.f	H.5.e	5. What critical barriers need to be addressed to implement the utility's long-term plan? Which of these barriers can be addressed by the utility or the Commission and which of these barriers are out of the utilities or the Commission's control? Which of these barriers would need to be addressed in the next 5-10 years? The utility should include a plan for addressing those barriers identified in the 5–10-year time frame, including direct actions that can be taken by the utility and opportunities to coordinate with other involved entities.	The critical barriers that need to be addressed to implement PGE's long-term plan are likely similar to those of other utilities across the West who are rapidly decarbonizing. The major barriers are transmission and the need to rapidly develop and scale new non-emitting technologies. Solutions will depend on regional cooperation, coordination, and federal policy and financial support; PGE's actions to expand partnerships regionally and continuously innovate new technologies are key near-term strategies toward successful, long-term pathways. Additional details are available in **Chapter 1, Clean Energy Plan**.	**Section 1.6, High-level opportunities, potential barriers, critical dependencies**
AI1.g	Not listed	To inform their responses to Staff's decarbonization planning questions, PGE and PAC should, within portfolio analysis:	--	--

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
AI1.h	H.1, H.1.a – H.1.c	Quantitatively evaluate opportunities and risks of emerging technologies, including, at a minimum: clean hydrogen, long duration storage, and offshore wind;	PGE developed and evaluated six emerging technology portfolios to specifically examine the implications of potential emerging technologies on portfolio costs and transmission needs. The emerging technology portfolio group included two hydrogen portfolios, an offshore wind portfolio, and a long duration storage portfolio.	**Chapter 11, Portfolio analysis**
AI1.i	H.2	Quantitatively evaluate potential impacts associated with building and transportation electrification, informed by current policy initiatives, and climate change and extreme weather;	PGE incorporated forecasts of building and transportation electrification from the DSP Part 2. PGE utilized a third-party study to inform how climate change was incorporated into the IRP via sensitivities.	**Chapter 6, Resource needs**
AI1.j	H.3	Quantitatively evaluate the impacts of transmission constraints and future transmission expansion; and	PGE developed three proxy transmission expansion options and evaluated 11 transmission portfolios to examine the implications of transmission opportunities and constraints on portfolio costs and resource actions.	**Chapter 9, Transmission** **Chapter 11, Portfolio analysis**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
AI1.k	H.4	Evaluate the sensitivity of the plans to other opportunities for enhanced regional coordination, including RA programs and improvements in transmission utilization.	PGE developed a Regional Transmission Organization (RTO) portfolio to examine the potential benefits PGE could realize from joining an RTO.	**Chapter 11, Portfolio analysis**
AI1.l	Not listed	To ensure that utility plans align with the clean energy targets in HB 2021, PAC and PGE's IRPs should:	--	--
AI1.m	D.2	Achieve the 2030 and 2035 clean energy targets under typical or expected weather and hydro conditions in those years. This should be demonstrated for the Preferred Portfolio and a set of alternative portfolios that test different paces of GHG reductions and different levels of community impacts; and	This methodology is applied to all portfolio analysis. All portfolios achieve the 2030 and 2035 emissions targets. Additional analysis on meeting resource adequacy needs under different weather and hydro conditions is also presented.	**Chapter 11, Portfolio analysis** **Appendix I, C-level analysis**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
AI1.n	D.3	Achieve resource adequacy in 2040 with no associated greenhouse gas emissions across the tested system conditions. This should be demonstrated for the Preferred Portfolio and a set of alternative portfolios that test different paces of GHG reductions and different levels of community impact.	All portfolios achieve the 2040 emissions target.	**Chapter 11, Portfolio analysis**
AI2.a	Not listed	For the first CEP and associated IRP, if the Preferred Portfolio relies on fossil fuel resource retirements or conversions to reduce GHG emissions, the utility should:	--	--
AI2.b	I.1	• Provide a rationale for and describe the risks and benefits associated with the retirement or conversion; and	PGE did not evaluate early retirements of existing thermal resources. One hydrogen portfolio did evaluate the impact of blending hydrogen at existing facilities but given the uncertainty of cost and performance characteristics the option is not included in the Preferred Portfolio.	**Chapter 11, Portfolio analysis**
AI2.c	I.2	• Identify whether each planned retirement reflects plans to	See above	--

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
		decommission the plant or plans to exclude the plant from Oregon rates.		
AI2.d	I.3	For the first CEP and associated IRP, if the Preferred Portfolio relies on operational changes relative to expected economic dispatch to reduce GHG emissions, including, but not limited to, application of operating or emissions constraints, inclusion of a GHG emissions cost in dispatch decisions, or out-of-state sales of fossil fuel generation, the utility should:	--	--
AI2.e	I.3	Quantify the impacts of those operational changes relative to expected economic dispatch in terms of generation (curtailed, reduced, or sold) and GHG emissions (avoided); and	Based on input from OPUC Staff PGE retained the use of economic dispatch in determining the output of existing thermal plants.	**Chapter 5, GHG emissions forecasting** **Chapter 11, Portfolio analysis**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
			From a modeling perspective, thermal generation (and the associated emissions) are allocated either to serve retail load or to market sales. The quantity of generation allocated to serve retail load contributes to the calculation of energy need, and the quantity for market sales affects system costs. Both inform portfolio analysis.	
AI2.f	I.4	Describe how the utility intends to implement those operational changes (e.g., through the development of operating or emissions limits, application of GHG emissions penalties, or execution of contracts with out-of-state entities), to the extent that they impact forecasted GHG emissions in the Action Plan window.	Actual operations depend on the actual weather, load, and market conditions, whereas the IRP forecasts depict simulated conditions based on averages conditions. Accordingly, IRP projections about the use of existing resources should not serve as constraints and/or direction to PGE's system operations. PGE operates its system to maintain reliability and minimize costs for PGE's customers.	--

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
			HB 2021 introduces emissions targets for PGE that are anticipated to be achieved by adding a significant increase in non-emitting generation and capacity resources to our portfolio. The IRP/CEP calculates that energy and capacity need by assuming reduced operation of thermal generation to serve retail load. In actual operations between now and 2030, non-emitting resources are anticipated to be added to our system and offset the need for thermal output that will otherwise serve retail load. Thermal generation will still be available to meet capacity needs.	

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
			Rather than model changes to thermal dispatch as an optional action, operations results are embedded in IRP/CEP modeling as an assumption and hence not quantifiable as a direct comparison to status quo operations. As we advance toward 2030, we intend to prepare for and coordinate changes in both resource procurement and operations that will affect how we schedule resources and manage net variable power costs. As PGE anticipates incorporating operational changes to meet our Western Resource Adequacy Program (WRAP) obligations in 2025 and our 2030 GHG target, we plan to highlight necessary changes to regulatory policy adapt to the change dynamics.	

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
AI3.a	J.1	The first CEP, or a designated section of the IRP that contains all information required by HB 2021, should be written for an introductory audience and include definitions of all key terms and acronyms.	PGE has developed **Chapter 1** as an accessible and free-standing summary of all information required by HB 2021, including our approach to portfolio analysis and a description of our Action Plan and analysis of emissions reductions.	**Chapter 1, Clean energy plan** **Appendix P, Acronyms**
AI3.b	J.3	The first CEP, or a designated section of the IRP that contains all information required by HB 2021, should also include:	--	--
AI3.c	J.3.a, J.3.b	A table that lists the GHG emissions assumptions for each existing and proxy resource modeled in the IRP, developed in partnership with DEQ. A table that lists the cumulative forecasted GHG emissions from each existing and proxy resource in the Preferred Portfolio under the Reference Case over the entire analysis horizon (at least 20 years) and the location of each emitting resource.	PGE developed GHG emissions assumptions and methodologies in coordination with DEQ. Emissions have been modeled for all resources consistent with these methodologies for use in portfolio analysis.	**Addendum: PGE CEP Data Template**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
AI3.d	J.3.c	The following graphs, which should include forecasted data under the Reference Case over the entire analysis horizon (at least 20 years) and at least three years of historical data:	--	--
AI3.e	J.3.c	Total annual portfolio GHG emissions, calculated in a manner consistent with the DEQ methodology, for the Preferred Portfolio and a set of alternative portfolios that test different paces of GHG reductions and different levels of community impacts.	Consistent with DEQ methodology, this analysis considers emissions for retail load service. PGE provides the resulting data each portfolio evaluated.	**Addendum: PGE CEP Data Template**
AI3.f	J.5.a	The total forecasted annual revenue requirement to serve Oregon customers for the Preferred Portfolio and a set of alternative portfolios that test different paces of GHG reductions and different levels of community impacts. This graph may exclude historical data if the forecasted revenue requirement does not approximate all costs borne by Oregon customers.	This data is provided for each portfolio.	**Addendum: PGE CEP Data Template**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
AI3.g	J.5.b	The total forecasted annual revenue requirement to serve Oregon customers, divided by the total forecasted retail sales in Oregon, for the Preferred Portfolio and a set of alternative portfolios that test different paces of GHG reductions and different levels of community impacts. This graph may exclude historical data if the forecasted revenue requirement does not approximate all costs borne by Oregon customers.	This data is provided for each portfolio.	**Addendum: PGE CEP Data Template**
AI3.h	J.4.a	Total annual GHG emissions by fuel type for resources in the Preferred Portfolio.	This data is provided for each portfolio.	**Addendum: PGE CEP Data Template**
AI3.i	J.4.b	Annual GHG emissions to serve Oregon customers by fuel type for the Preferred Portfolio.	This data is provided for each portfolio.	**Addendum: PGE CEP Data Template**
AI3.j	J.4.c	Total annual generation by fuel type for resources in the Preferred Portfolio.	Consistent with the emissions reporting above, PGE has included emitting sources only in this graph. All non-emitting sources would have emissions of zero.	**Addendum: PGE CEP Data Template**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
AI3.k	J.4.d	Annual generation serving Oregon customers by fuel type for the Preferred Portfolio.	Consistent with the emissions reporting above, PGE has included emitting sources only in this graph. All non-emitting sources would have emissions of zero.	**Addendum: PGE CEP Data Template**
AI3.l	J.4.e	Annual weighted average heat rate by fuel type for resources in the Preferred Portfolio.	PGE has included emitting sources only in this graph. Heat rate is not applicable to non-emitting sources.	**Addendum: PGE CEP Data Template**
AI3.m	J.6	In the 2023 IRP, PGE and PAC should provide a table that describes the utility's annual plans for the use of RECs associated with renewable energy generated by or contracted to the utility in the Preferred Portfolio under the Reference Case over the entire analysis horizon (at least 20 years). The table should clearly delineate between RECs that are expected to be:	--	--
AI3.n	J.6.a	Retired on behalf of Oregon customer load for RPS compliance in Oregon;	This data is provided for the Preferred Portfolio.	**Addendum: PGE CEP Data Template**
AI3.o	J.6.a	Retired on behalf of Oregon customer load for voluntary sales;	Included in CEP Data template	**Addendum: PGE CEP Data Template**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
AI3.p	J.6.a	Retired on behalf of customer load in a different state where the utility serves customers (for either compliance or voluntary sales);	Not applicable to PGE	--
AI3.q	J.6.a	Banked for future Oregon compliance;	Included in CEP Data template	**Addendum: PGE CEP Data Template**
AI3.r	J.6.a	Banked for compliance in a different state where the utility serves customers;	Not applicable to PGE	--
AI3.s	J.6.b	Utilities must report the approximate number of MWhs not associated with RECs reported in the referenced table that are generated from renewable energy technologies.	Included in CEP Data template	**Addendum: PGE CEP Data Template**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
AI3.t	Not listed	Staff, utilities, and all interested stakeholders should collaboratively develop by February 1, 2023, an agreed upon approach to capturing additional standardized information and data related to their CEP and how they will make it publicly available in a similar fashion on their websites.	PGE established a dedicated website for all our resource plans (e.g., IRP, CEP, and DSP) and provides access to information in new ways. We currently publish our IRP roundtable materials on our IRP website as well as associated Q&A responses and video recordings. Our website also provides additional materials and other relevant information regarding the CEP. Based on participant feedback, we updated our indexing system to allow easier navigation to specific topics of interest within the many hours of meeting recordings and slides presented. PGE has also provided all required quantitative data in the format of the template provided by Staff to PGE on February 24, 2023, which is publicly available as part of our CEP/IRP filing.	Web materials are available at https://portlandgeneral.com/about/who-we-are/resource-planning **Addendum: PGE CEP Data Template**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
AI3.u	J.2	Utilities should, moving forward, post any recordings made of IRP public input meetings on its website, and if a recording is not available, provide a general summary of comments received at the meeting.	All recordings are posted on our website, see https://portlandgeneral.com/about/who-we-are/resource-planning/integrated-resource-planning/irp-public-meetings	**Section 14.2.8, Transparency and accessibility** **Appendix C, 2023 IRP public meeting agendas**

Appendix C. 2023 IRP public meeting agendas

PGE manages IRP development through a collaborative, interactive process with an active customer and public stakeholder group. All IRP meetings are open to the public and are generally hosted once a month. In addition, PGE continues to engage community-based organizations via the Learning Lab[394] venue, originally utilized during DSP development, to share IRP and CEP related analysis and concepts with stakeholders who have less experience participating in technical workshops.

PGE has hosted 30 public meetings and seven Learning Labs during the 2023 IRP development process, makes all meeting materials available on the IRP webpage, and advertises public meeting dates there as well. The comments and suggestions shared with us are incorporated into our thinking and our final IRP, and a summary of the comments we received are posted to our IRP webpage.

This summary of our meeting dates and topics, hosted in support of the 2023 IRP, is a collaboration between PGE and our dedicated stakeholder community who have put in the time to advocate for their communities. A summary of meeting topics is shown in **Table 95**, **Table 96**, **Table 97**, and **Table 98**. We have attempted to incorporate what we have heard and plan to continue to engage and evolve through this 2023 IRP and into future IRP development.

[394] https://portlandgeneral.com/about/who-we-are/resource-planning/clean-energy-planning

C.1.1 2020 Public meetings[395]

Table 95. 2020 public meeting summary

Roundtable	Agenda topics
Roundtable 20-1 March 19, 2020[396]	Agenda: IRP schedule and next steps, values refresh, capacity assessment, energy efficiency
Roundtable 20-2 April 14, 2020[397]	Agenda: Transmission, integration cost drivers enabling study, climate adaptation enabling study
Roundtable 20-3 May 20, 2020[398]	Agenda: Capacity Assessment – Preliminary Model Development Workshop, climate adaptation enabling study, Stakeholder input for design/scoping
Roundtable 20-4 July 29, 2020[399]	Agenda: Background on Integrated Resource Planning (IRP), values discussion
Roundtable 20-5 August 19, 2020[400]	Agenda: Price Futures, capacity assessment baseline, supply-side options

[395] https://portlandgeneral.com/about/who-we-are/resource-planning/irp-public-meetings
[396] March 19, 2020 meeting materials available at https://assets.ctfassets.net/416ywc1laqmd/VorVAYOPLXyi1R6uNinEL/d77876929095caf26665f35f90a9363c/2020-03-17-irp-roundtable-20-1.pdf
[397] April 14, 2020 meeting materials available at https://assets.ctfassets.net/416ywc1laqmd/5KMI0Fqc36iRGIA4FvYHv8/1775a0f32fb5014a4a8cc17dd44ffc6f/2020-04-irp-roundtable-20-2.pdf
[398] May 20, 2020 meeting materials available at https://assets.ctfassets.net/416ywc1laqmd/69E4wCSDi254PL7EwJMneu/1da2f516213a67a4f6d0a2458388a202/2020-05-20-irp-roundtable-20-3.pdf
[399] July 29, 2020 meeting materials available at https://assets.ctfassets.net/416ywc1laqmd/7rcLN02TYJg4soP2zvicTu/a188a0a68b2bb1a17e0333712d6ae575/2020-07-29-irp-roundtable-20-4.pdf
[400] August 19, 2020 meeting materials available at https://assets.ctfassets.net/416ywc1laqmd/4QqSCUHVJkUMNTgW5BNiaZ/701668fd213498cc381f13b751eeb407/2020-08-19-irp-roundtable-20-5.pdf

Roundtable	Agenda topics
Roundtable 20-6 October 28, 2020[401]	Agenda: Load forecast for IRP update; capacity need, RPS position, energy position; market prices for IRP update
Roundtable 20-7 November 18, 2020[402]	Agenda: Change to Production Tax Credits for 2019 IRP update, interconnection costs (updated for 2019 IRP update), capacity contributions, LUCAS101, ROSE-E 101
Roundtable 20-8 December 10, 2020[403]	Agenda: 2019 IRP update – draft portfolio analysis, 2020 Distributed Energy Resources (DER) and Flex Load Potential Study.

C.1.2 2021 Public meetings

Table 96. 2021 public meeting summary

Meeting	Agenda topics
Roundtable 21-1 February 17, 2021[404]	Agenda: Price forecast part 1, supply side resource options
Roundtable 21-2 March, 21, 2021[405]	Agenda: Community values and the 2022 IRP, modeling overview and schedule, transmission update

[401] October 28, 2020 meeting materials available at https://assets.ctfassets.net/416ywc1laqmd/2XkzCQDPsoEmae8kJn5ckD/6c2e1f9462d8cc16ce8ec7752e57d67a/irp-roundtable-20-6.pdf
[402] November 18, 2020 meeting materials available at https://assets.ctfassets.net/416ywc1laqmd/2ffV7LUhMxgl3XwIjEXqqV/68f6668b8152d686ebe98a7025a7ff05/irp-roundtable-_20-7.pdf
[403] December 10, 2020 meeting materials available at https://assets.ctfassets.net/416ywc1laqmd/60OlDmUO5U9YWN6pcfNv0a/3620744cec9c57c6538ecd31fd10a817/irp-roundtable-20-8.pdf
[404] February 17, 2021 meeting materials available at https://assets.ctfassets.net/416ywc1laqmd/5fZx2C5US1n7iSasPRjU4x/b752f1a798fe5e39255129e760af70ee/irp-roundtable-21-1.pdf
[405] March 21, 2021 meeting materials available at https://assets.ctfassets.net/416ywc1laqmd/FYE0Gf8xbQgPZ4To88oZx/9f46ea7c1b93f55c1a0188160273880f/irp-roundtable-march-21-2.pdf

Meeting	Agenda topics
Roundtable 21-3 May 27, 2021[406]	Agenda: Price forecasts part 2, IRP uncertainty, capacity assessment
Roundtable 21-4 June 24, 2021[407]	Agenda: Technology costs, energy position
Roundtable 21-5 July 22, 2021[408]	Agenda: Load forecast
Roundtable 21-6 August 25, 2021[409]	Agenda: DER and flexible load phase 1 study
Roundtable 21-7 October 28, 2021[410]	Agenda: PGE's next IRP – update on timing,[411] Oregon House Bill 2021; Portfolio requests
Roundtable 21-8 November 18, 2021[412]	Agenda: Pricing methodology; Supply-side options; Portfolio requests

[406] May 27, 2021 meeting materials available at https://assets.ctfassets.net/416ywc1laqmd/CNMm5LJjd1EVRDUkfHauN/4f39030995783e132df0bbe94d7d5f30/IRP_Roundtable_May_21-3.pdf
[407] June 24, 2021 meeting materials available at https://assets.ctfassets.net/416ywc1laqmd/3cvd1UgpapBboirkYJLTEd/132bb6ab8ce967f92c33549560400ef5/IRP_Roundtable_June_21-4.pdf
[408] July 22, 2021 meeting materials available at https://assets.ctfassets.net/416ywc1laqmd/2eI3mKz2HVK1uEPogSDofW/09fbb8476086009ffe7d181dfb95dc12/IRP_Roundtable_July_21-5.pdf
[409] August 25, 2021 meeting materials available at https://assets.ctfassets.net/416ywc1laqmd/7nr8YY8Kpir36zOx9mNC9u/ab1da296963265fca522082f72d3a0d6/irp-roundtable-august-21-6.pdf
[410] October 28, meeting materials available at https://assets.ctfassets.net/416ywc1laqmd/13yKrhtKw5KkMU0WfnmJSz/03626e36c13462e190454881e88396a2/irp-roundtable-oct-21-7.pdf
[411] Press release available at: https://portlandgeneral.com/news/2021-10-15-pge-plans-to-nearly-triple-clean-resources-by-2030
[412] November 18, 2021 meeting materials available at https://assets.ctfassets.net/416ywc1laqmd/1UeTCdvEqHlpH1MRPOGo85/45b03c61b37dfaba7e0a434c8a8cfb3d/IRP-Roundtable-November-21-8.pdf

C.1.3 2022 Public meetings

Table 97. 2022 public meeting summary

Meeting	Agenda topics
Roundtable 22-1 January 6, 2022[413]	Agenda: 2022 kickoff and schedule, clean energy plan, climate adaptation study, flexibility study, portfolio requests
Roundtable 22-2 March 14, 2022[414]	Agenda: Order 21-215: UM 1728 Settlement – Qualifying Facilities (QF) Sensitivities and Effective Load Carrying Capability (ELCC) Sensitivities
Roundtable 22-3 April 14, 2022[415]	Agenda: Solar Inverter Loading Ratios, GridPath Flexibility Analysis, Climate Adaptation Study, Final Load Forecast, RPS Modeling, and Price Update
Roundtable 22-4 May 17, 2022[416]	Agenda: Sequoia and ROSE-E Updates, Hybrid Resource Characteristics, Clean Energy Plan Update
Roundtable 22-5 June 30, 2022[417]	Agenda: House Bill 2021 and IRP Modeling, 2023 IRP Portfolio Analysis, Resource Adequacy Market Access

[413] January 6, 2022 meeting materials available at https://assets.ctfassets.net/416ywc1laqmd/7cxcVacdmTWeIFsfP7G9cG/2a99ba1e764c753b02b899645d5b692e/IRP_Roundtable_January_22-1.pdf
[414] March 14, 2022 meeting materials available at https://assets.ctfassets.net/416ywc1laqmd/6hRQPptYmblk9Uvup4JDJU/f747f759ce667a80efcd041a12526c12/IRP_Roundtable_March_22-3.pdf
[415] April 14, 2022 meeting materials available at https://assets.ctfassets.net/416ywc1laqmd/7b7HWYRGD36HHCHeWbBqYS/c17bd893aa9118ad2911293e680ed35f/IRP_Roundtable_April_22-4.pdf
[416] May 17, 2022 meeting materials available at https://assets.ctfassets.net/416ywc1laqmd/4YnCZf5PtwTE5ska7tclxS/a18aff0034e3fd9730f0a3f168619c87/IRP_Roundtable_May_22-5.pdf
[417] June 30, 2022 meeting materials available at https://assets.ctfassets.net/416ywc1laqmd/2e732S4plWpR59ID7ZDV8q/270c1816f005d6816e63ac88e9e61879/IRP_Roundtable_June_22-5.pdf

Meeting	Agenda topics
Roundtable 22-6 July 21, 2022[418]	Agenda: Need Futures, Yearly Capacity Needs, Distributed Energy Resources, and Updated Western Electricity Coordinating Council (WECC) Pricing
Roundtable 22-7 August 18, 2022[419]	Agenda: Transmission inventories, Hybrid resource locations, Draft supply side ELCC values, Draft energy load resource balance
Learning Lab #1[420]	PGE clean energy plan kickoff
Roundtable 22-8 September 15, 2022[421]	Agenda: Clean Energy Plan Workshop Informational, Inflation Reduction Act, Transmission
Roundtable 22-9 October 20, 2022[422]	Agenda: Transmission part II, climate study, flexibility study, resource adequacy, clean energy plan update
Learning Lab #2[423]	Agenda: DSP lessons learned, partner comments, PGE actions, update on Energy Trust of Oregon (ETO) collaboration, IRP 101, grid needs and non-wires solutions (NWS), DSP/CEP intersection: NWS, Community Benefit Indicator (CBI), Community-based Renewable Energy (CBRE).

[418] July 21, 2022 meeting materials available at https://assets.ctfassets.net/416ywc1laqmd/12mmGu2JZNE3tcjLkK6irQ/5220013d807848c057c27cbbed41a46e/IRP_Roundtable_July_22-6.pdf
[419] August 18, 2022 meeting materials available at https://assets.ctfassets.net/416ywc1laqmd/1ltEzsTwlgoFoOfVxtuGob/4bff485e57a30ad1549d061094a44347/IRP_Roundtable_August_22-7.pdf
[420] Meeting video archive available at https://www.youtube.com/watch?v=r-IPdBHsCjA
[421] September 15, 2022 meeting material available at https://assets.ctfassets.net/416ywc1laqmd/70ZtUZu614Muls6lKSpNm0/72d85334b7e9f4152a169c230393970e/IRP_Roundtable_September_22-8_92822.pdf
[422] October 20, 2022 meeting material available at https://assets.ctfassets.net/416ywc1laqmd/3Bv5b1kzoD9flvapvcpBrA/981ab90a5ef126db416dd0567a6b5bd5/IRP_Roundtable_October_22-9_V2.pdf
[423] Meeting video archive available at https://www.youtube.com/watch?v=ywCd4GjF0tw

Meeting	Agenda topics
Roundtable 22-10 November 16, 2022[424]	Agenda: Non-cost-effective distributed energy resources, emissions forecasting, CBRE and community benefits indicators overview, transmission part III, portfolios
Learning Lab #3[425]	Agenda: Recap, community-based resources and community benefits indicators, resilience, RFP 101, IRP roundtable recap
Roundtable 22-11 December 16, 2022[426]	Agenda: Emissions forecasting part II, community benefits indicators update, price futures update, transmission part iv, portfolio scoring metrics, draft portfolio results

[424] November 16, 2022 meeting material available at https://assets.ctfassets.net/416ywc1laqmd/3lvg7tPLLkie7L8QiDS91t/45dd54a03de06c047106741ba77e0858/IRP_Roundtable_November_22-10-Final.pdf
[425] Meeting video archive available at https://www.youtube.com/watch?v=s4F6bG_tpGs
[426] December 16, 2022 meeting materials available at https://assets.ctfassets.net/416ywc1laqmd/7AUDtFKsutaZB5zUWTzbHo/db4f426352329e0fc05d30f50325b2f7/IRP_Roundtable_December_22-11.pdf

C.1.4 2023 Public meetings

Table 98. 2023 public meeting summary

Meeting	Agenda topics
Roundtable 23-1 January 26, 2023[427]	Agenda: Informational community benefits indicators, draft portfolio analysis results and scoring, waiver/IRP filing update, draft Action Plan
Learning Lab #4[428]	Agenda: Community engagement update, resilience update, potential CBRE acquisition paths update, community benefits indicators update, Community Benefits and Impacts Advisory Group (CBIAG) update, distribution system plan Distributed Generation (DG) map update, previous integrated resource plan (IRP) December roundtable recap.
Roundtable 23-2 March 8, 2023[429]	Agenda: Data center energy efficiency opportunities (with Energy Trust of Oregon), price futures, draft portfolio analysis results and Preferred Portfolio part II, draft Action Plan part II
Learning Lab #5	
Roundtable 23-3 March[430]	Agenda: 2023 IRP Action Plan, UM 1728

[427] Meeting materials available at https://portlandgeneral.com/about/who-we-are/resource-planning/integrated-resource-planning/irp-public-meetings
[428] Meeting video archive available at https://www.youtube.com/watch?v=BvUdkenX4Is
[429] Meeting materials available at https://portlandgeneral.com/about/who-we-are/resource-planning/integrated-resource-planning/irp-public-meetings
[430] Meeting materials available at https://portlandgeneral.com/about/who-we-are/resource-planning/integrated-resource-planning/irp-public-meetings

Appendix D. Load forecast methodology

This appendix provides detail about PGE's load forecast methodology and results for the 2023 IRP.

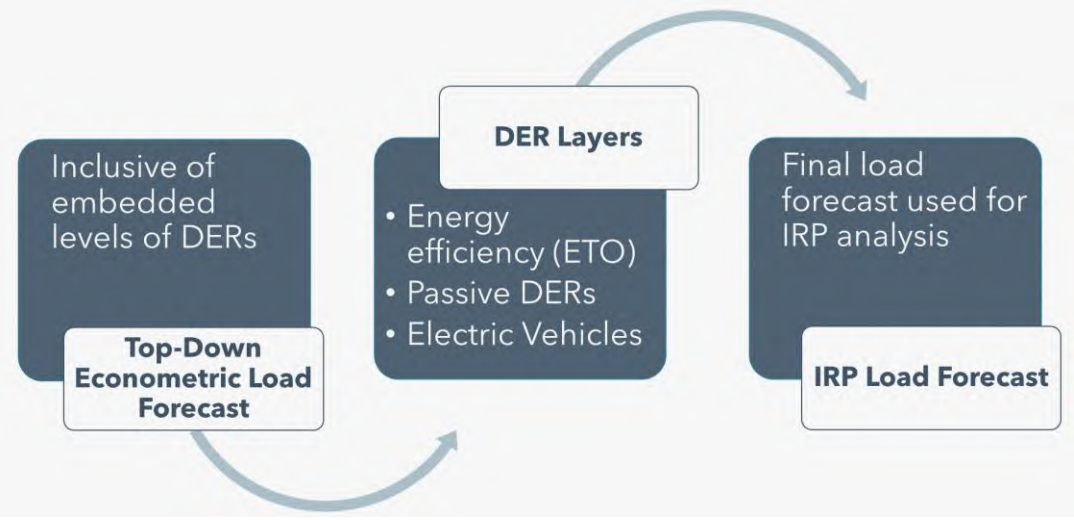
As discussed in **Section 6.2, Distributed Energy Resource (DER) impact on load**, the load forecast combines the top-down econometric forecast and the passive distributed energy resources (DER) forecast. This appendix focuses on the top-down econometric forecast models and provides annual summaries of forecast results.

Unless specified, the load values in this appendix reflect the cost-of-service supply load and do not include long-term direct access loads. The forecast vintage used is the March 2022 load forecast.

D.1 Load forecast methodology

PGE's load forecast is a compilation of several model outputs. The top-down econometric load forecast is the focus of this appendix. This is a set of models aiming to capture the relationships between PGE's energy deliveries and various structural trends and economic drivers. The impacts of DERs – primarily energy efficiency, rooftop solar, and transportation electrification – are modeled outside the top-down econometric framework and described in **Section 6.3, Load scenarios**. The incremental impacts of these loads are then 'layered' onto PGE's base forecast, as presented in **Figure 114**.

Figure 114. Load forecast methodology



PGE's top-down econometric load forecast consists of models focused on two distinct time horizons. **Table 99** describes some of the specific differences.

For the IRP process, PGE updates its long-term models to estimate growth rates for aggregated customer classes: residential, commercial, and industrial. However, the forecast result is dependent on the estimation of the near-term models as a starting point. The long-term growth rates described in this appendix are applied to the result of the near-term forecast model. The near-term model is focused on capturing near term business cycle impacts and individual forecasts for large projects. This model is submitted in PGE's general rate case (GRC) and annual update tariff (AUT) filings.

Table 99. Near term- vs. long-term model

Near Term (1-5 Years)	Long-Term (5+ Years)
25 regression-based monthly energy deliveries models Business cycle influences energy deliveries Individual customer forecast for ~25 large customers Historic data from 2010 to 2021 Explicitly removes incremental energy efficiency Updated as frequently as every quarter	Convergence to long-term growth rates, agnostic to the business cycle and specific customer growth. Three aggregated customer class growth rate models. Historic data from 2000 to 2021. Assumes energy efficiency is embedded in growth rates. Growth rates are appended to near-term model output. Updated annually to support IRP.

D.1.1 Refinements since last IRP

Development of PGE's econometric load forecast reported in this IRP began in 2020 with a review of critical models and an assessment of key issues raised by stakeholders during the 2019 IRP process.

In October 2020, at IRP Roundtable 20-6,[431] we discussed the impacts of COVID-19 on energy deliveries and out-of-model adjustments made in the near-term load forecast to account for those impacts. We also presented the testing of alternate economic drivers,

[431] Oct. 28, 2020, IRP Roundtable 20-6: https://assets.ctfassets.net/416ywc1laqmd/2XkzCQDPsoEmae8kJn5ckD/6c2e1f9462d8cc16ce8ec7752e57d67a/irp-roundtable-20-6.pdf

particularly focusing on the use of local drivers, for the industrial forecast model in response to feedback from CUB in LC-73.

In July of 2021, at IRP Roundtable 21-5,[432] we presented the preliminary long-term and peak demand models, recommended alternative industrial drivers - including benchmarking to utility peers – and requested feedback on driver selection and scenarios inputs.

In April of 2022, at IRP Roundtable 22-3,[433] we presented the final model results reflecting the March 2022 econometric load forecast and comparison to the 2019 IRP Update.[434]

Several refinements are reflected in the latest models.

- **COVID-19 Indicator**: For the 2019 IRP Update, PGE utilized out-of-model adjustments to account for the impact of COVID-19 in the near-term models. This method was purely pragmatic, an approach to manage the extreme effects quickly. Since that time, we have implemented a more robust approach to account for the impacts of COVID-19 in the econometric model via an indicator variable in the regression analysis. A further explanation of this process can be found in **COVID-19 Impact on short-term energy use.**
- **Industrial Driver**: PGE tested several local and national economic drivers for its industrial model. Variables tested included: US Gross Domestic Product (GDP), Total Oregon Income, Mean Oregon Income, Total Non-Farm Oregon Employment, Oregon GDP, and county-level GDP for PGE's service territory. Total Oregon Income was found to have the most robust relationship with PGE's industrial energy deliveries and was selected as the primary driver for the long-term industrial model.
- **Peak Demand Model Structure**: PGE separated the peak model into two seasonal models; separate cooling and heating models allow for individual seasonal-level model specifications. The peak model specification can be found in **Section D.1.5, Peak model**.

[432] July 22, 2021, IRP Roundtable 21-5: https://assets.ctfassets.net/416ywc1laqmd/2eI3mKz2HVK1uEPogSDofW/09fbb8476086009ffe7d181dfb95dc12/IRP_Roundtable_July_21-5.pdf
[433] Apr. 14, 2022, IRP Roundtable 22-3: https://assets.ctfassets.net/416ywc1laqmd/2e732S4plWpR59ID7ZDV8q/270c1816f005d6816e63ac88e9e61879/IRP_Roundtable_June_22-5.pdf
[434] PGE'S 2019 IRP Update: https://assets.ctfassets.net/416ywc1laqmd/7JkfpRUwMrqCwfKsxAPG3g/9703398aa3212f8532ffb5ced616af87/2019-irp-update-04-20-2021.pdf

D.1.2 Inputs

Normal weather assumption

The COVID-19 pandemic has shifted energy usage in several ways. Residential usage experienced a significant increase, while in the commercial segment, initial shutdowns had a stark – but short-lived - impact on energy deliveries. PGE's industrial segment was impacted least by COVID-19 and has grown dramatically since the 2019 IRP. Recent trends impact the near-term forecast, which is the starting point for the long-term forecast.

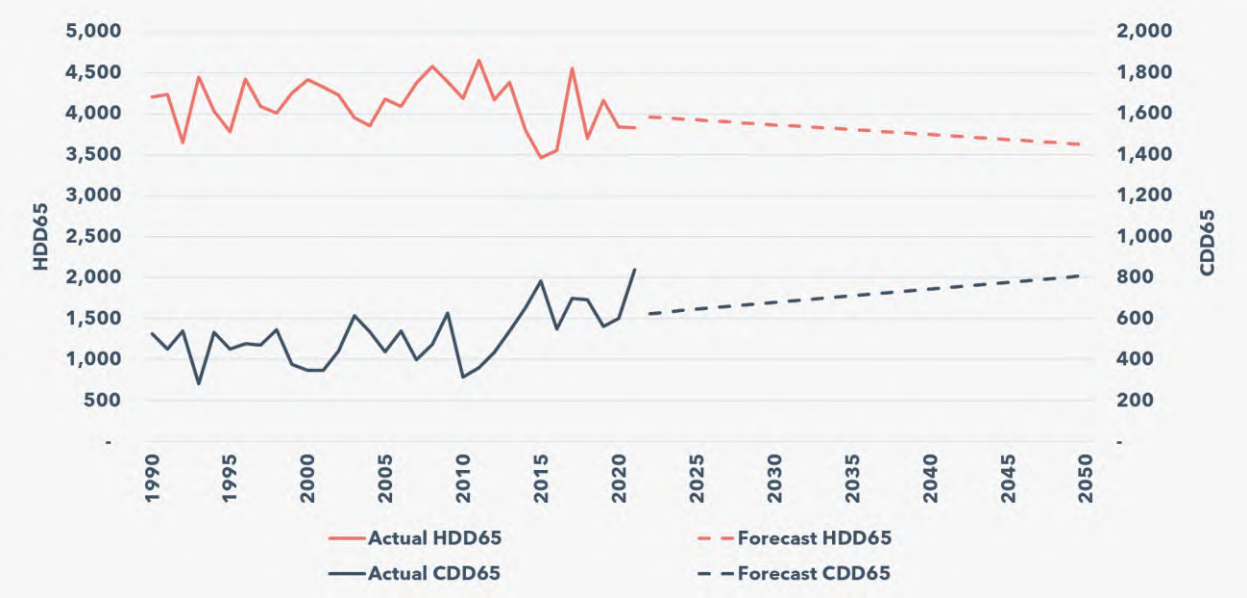
PGE assumes normal weather year as an input to the load forecast rather than a weather forecast. Weather variability different from the normal weather assumption is expected. The intention is to use an unbiased weather assumption such that the actual weather is warmer or cooler than normal 50 percent of the time. PGE uses a trend to create the forward-looking normal weather assumption that reflects the gradually warming climate. The methodological approach continues the trend observed since 1975, using data since 1941 to "hinge" the initial point of that trend.[435] **Figure 115** shows historical actual and forward-looking normal for heating and cooling degree days (HDD and CDD)[436] using this methodology.

A review was performed in the 2023 IRP to compare this input assumption to specific Representation Concentration Pathway (RCP) Climate Change Scenarios. This review finds PGE's methodology to fit within the reasonable bounds of this scenario analysis. This is described further at the end of this appendix section.

[435] Livezey, Robert E., *et al.* "Estimation and extrapolation of climate normals and climatic trends." *Journal of Applied Meteorology and Climatology* 46.11 (2007): 1759-1776. https://journals.ametsoc.org/doi/pdf/10.1175/2007JAMC1666.1

[436] Heating and cooling degree days (HDD and CDD) are the number of degrees that a day's temperature deviates from the temperature set point. For heating degree days, the measurement represents the extent to which a building would need to be heated to reach the temperature set point, and for cooling degree days, the measurement represents the extent to which a building would need to be cooled to reach the temperature set point. For these regressions with monthly data, HDD and CDD are summed for all days in the month. As an example, on a day with an average temperature of 75° F, HDD65 = 0 and CDD65 = 75 - 65 = 10.

Figure 115. Normal weather expectation in terms of heating degree days and cooling degree days



COVID-19 Impact on short-term energy use

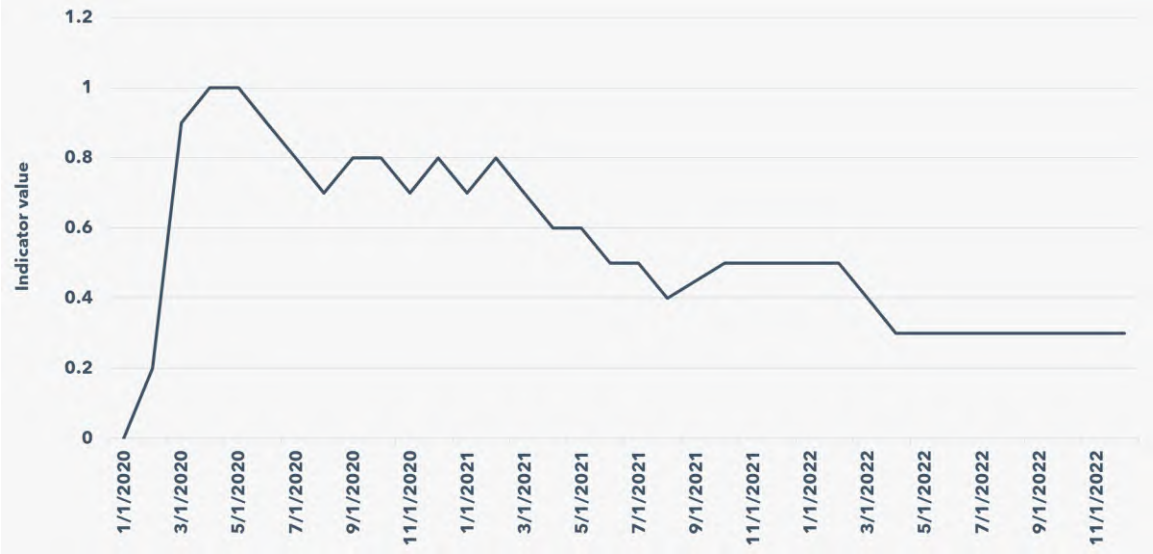
To account for changes in usage, PGE utilized a COVID-19 indicator variable based on the percent of work from home in Oregon produced by the Oregon Office of Economic Analysis.[437] The indicator variable is designed to range from 0 to 1, work from home peaked in May 2020, and that level was set to "1". The indicator was then scaled down based on monthly work from home compared to the May 2020 level. **Figure 116** presents the COVID-19 variable assumptions.

This variable was used in the residential model to account for the increase in usage and in the commercial model to account for the lower usage associated with the COVID-19 pandemic. Recent trends show that COVID-19 has permanently changed the way residential customers use energy. For the forecast, PGE assumed a slow decrease in work from home until April 2022, when long-term equilibrium will be reached at 0.3. This assumes that residential usage will remain elevate at 30 percent of the peak impact of COVID-19.

For the long-term models this variable is phased out in the long-term and does not impact the long-term growth rate beyond correcting the model fit in the short term.

[437] Lehner, Josh. "Just How Much is Working from Home on the Rise?" Available at: https://oregoneconomicanalysis.com/2021/12/16/just-how-much-is-working-from-home-on-the-rise/

Figure 116. COVID-19 indicator variable

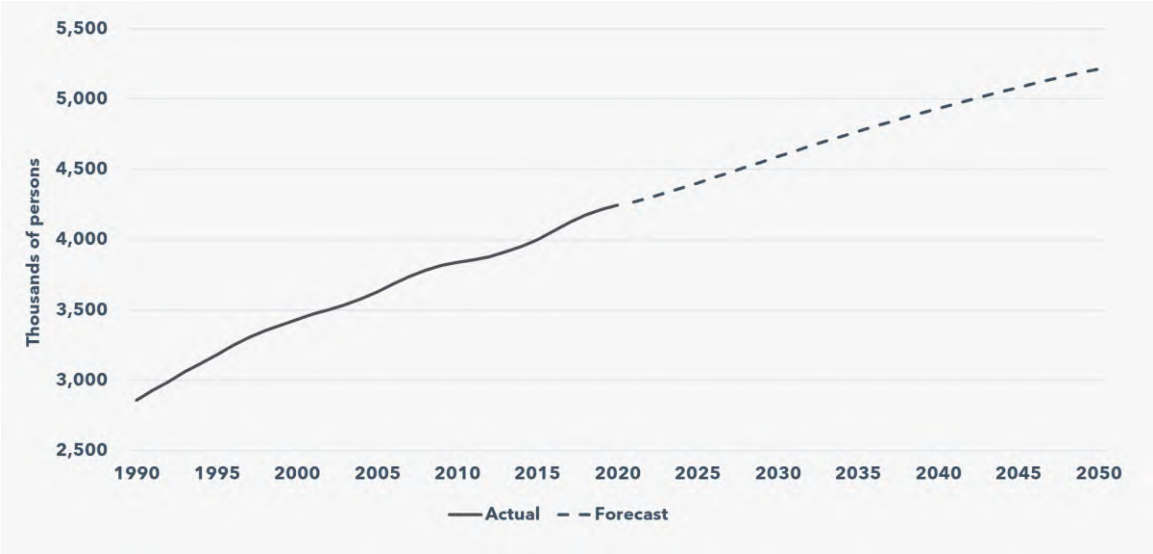


Long-term macroeconomic drivers

Oregon Population

Oregon's Population is closely related to the number of households in PGE's service area. It is used as a driver of residential customer count in PGE's residential energy deliveries model. PGE uses the Oregon Office of Economic Analysis's forecast of Oregon Population, extrapolated from 2030 to 2050. The projected average annual growth rate from 2022 to 2050 is 0.7 percent. **Figure 117** shows the historical actual and projected population levels.

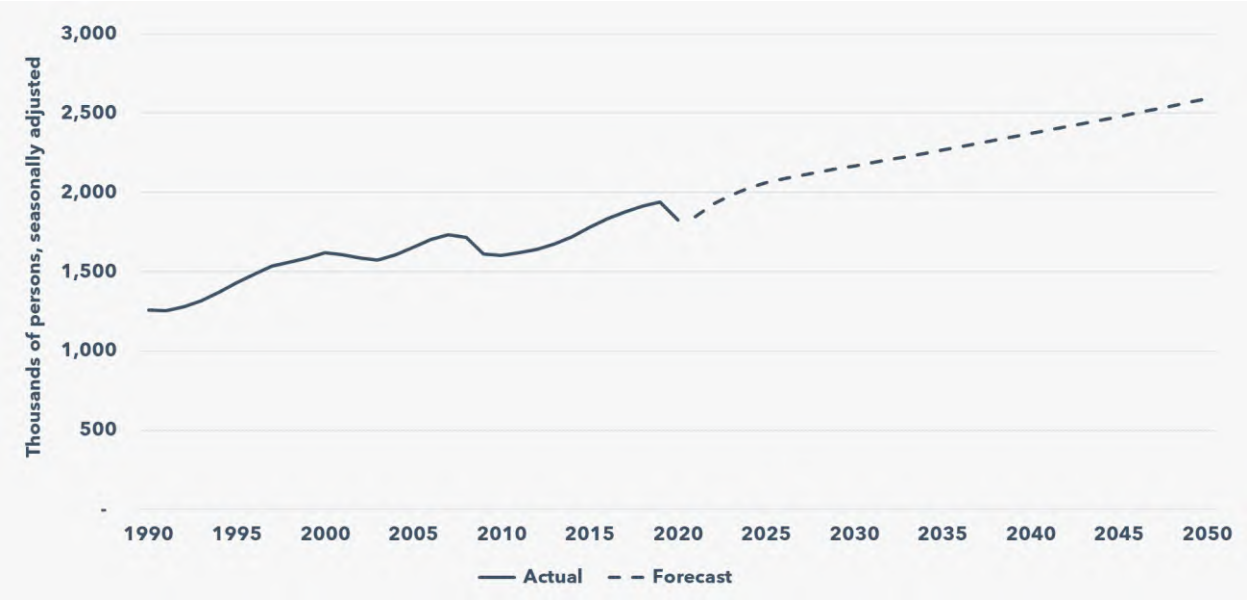
Figure 117. Oregon population



Oregon total non-farm employment

The level of employment in Oregon is the economic driver of PGE's commercial energy deliveries forecast. PGE uses the Oregon Office of Economic Analysis's forecast of employment, extended to 2050. The projected average annual growth rate from 2022 to 2050 is 0.9 percent. **Figure 118** shows the historical actual and forecasted levels of Total Non-Farm Employment.

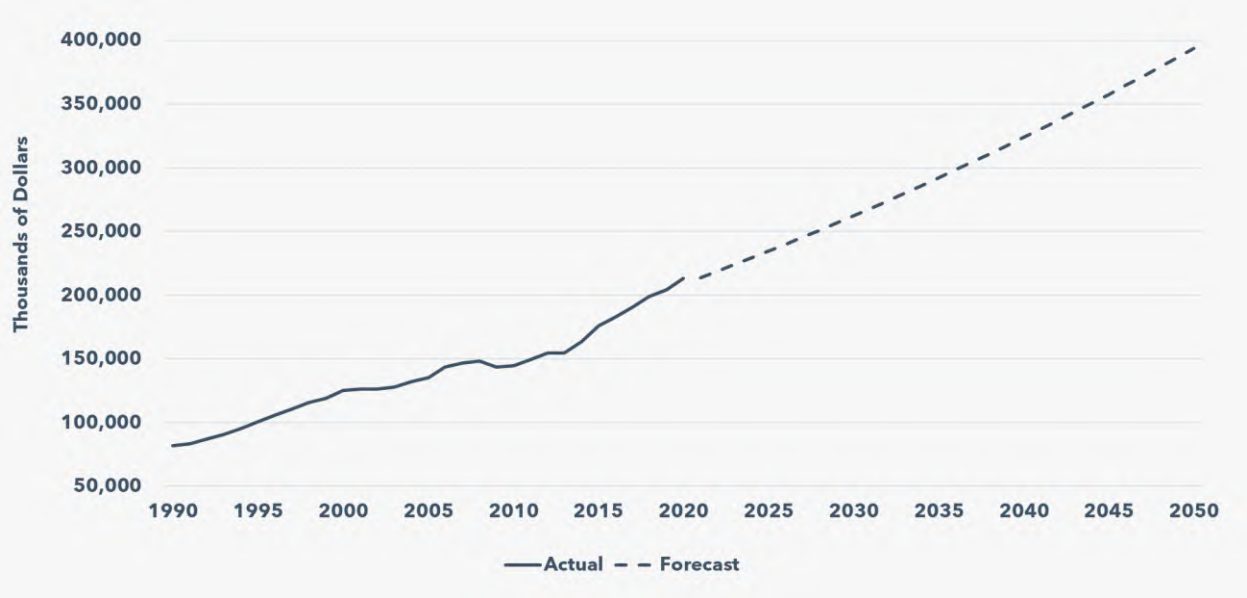
Figure 118. Oregon's total non-farm employment



Oregon Total Personal Income

Oregon's Total Personal Income is the economic driver of PGE's industrial energy deliveries forecast. Total Personal Income is income of individuals from wages, salaries, business ownership, interest and dividends, Social Security, and other government benefits. Measures of income are often used as an indication of financial health. PGE uses the vendor provided forecast released by Woods and Pool in 2021 for this input assumption. The projected average annual growth rate from 2021 to 2050 is 2.1 percent. **Figure 119** shows the historical actual and forecasted Total Personal Income.

Figure 119. Oregon total personal income



D.1.3 Model development and evaluation

In response to OPUC Staff feedback in PGE's 2016 Integrated Resource Plan and as part of continual methodology refinement, PGE worked to standardize and more formally document its model development process and evaluation criteria.[438]

A series of testing steps are used to develop long-term forecast models. This testing includes a univariate review of the underlying structure of the energy deliveries time series; an examination of the relationship between energy deliveries to drivers, including weather variables; and the testing of alternative model structures, including naïve, differenced, and "automatic" ARIMA. The model fit statistics, coefficients, and residuals are reviewed to compare and select alternate models.

- **Univariate analysis**. Univariate analysis of historical sector-level time series is conducted to identify trends, seasonality, cycles, breaks, and outliers. The first step is to inspect the data series visually. Then the autocorrelation of the series is reviewed, and statistical tests such as the Augmented Dickey Fuller (ADF) and Kwiatkowski, Phillips, Schmidt, and Shin (KPSS) tests are used to assess the underlying structure of the data. When tests imply non-stationarity in a variable, PGE explores data transformations, trend variables, and naïve forecasts.

[438] Staff Comments available at: https://edocs.puc.state.or.us/efdocs/HAC/lc66hac143454.pdf

- **Weather responsiveness**. Scatter plots and testing in the regression models are used to determine the appropriate HDD and CDD variables for inclusion in each model. **Figure 120** shows the weather responsiveness of the three long-term models with monthly energy deliveries plotted against average monthly temperature using data since 2000.

In **Figure 120**, the scatter follows a relatively tight "U" shape, indicating that residential energy usage increases as the average temperature falls under 60˚F and as the average temperature is higher than 65˚F. This implies using an HDD variable calculated from a 60˚F base and a CDD variable with a 65˚F base. In (b), commercial energy deliveries increase as the average temperature falls under 50˚F and when the average temperature is higher than 60˚F. In (c), the broad scatter implies that energy deliveries to the industrial class have no significant weather dependence.

- **Residual review**. PGE reviews the autocorrelation and normality of residuals in the models for any alternative model structures considered. Ideally, residuals are white noise, meaning they are uncorrelated, have a mean of 0, have constant variance, and are normally distributed. The extent to which residuals of a regression statistically differ from white noise indicates the potential to improve the model specification. Residuals that are meaningfully correlated might lead to the addition of autoregressive or moving average terms to the model or re-visiting the regression model specification.
- **Alternate forecasts and out-of-sample testing**. PGE reviews a variety of alternate model specifications for each of the forecast groups. Testing includes: 1) models using a variety of economic drivers, as well as those with no economic driver; 2) models with and without monthly indicator variables; and 3) models using a variety of data transformations. As part of the standardization of the model evaluation and to benchmark against the most simplistic models, PGE also tests naïve and seasonally naïve forecasts. Out-of-sample testing, which uses a training period to estimate the model and a testing period to evaluate model performance, was included as a part of PGE's testing process in the 2019 IRP Load Forecasting Appendix. While PGE intends to employ this method in the future, out-of-sample testing was not performed for the forecast vintage used in this IRP. PGE did not perform out-of-sample testing because the dramatic but short-lived period of impact for the COVID-19 indicator variable did not allow for a long enough period to reflect useful testing.

D.1.4 Long-term energy models

Residential model

The long-term residential energy deliveries model, shown in **Equation 1**, comprises of forecasts for both customer count, an annual model based on Oregon Population (**Equation 3**), and use-per-customer, a monthly model based on relationships to Oregon Total Non-Farm employment, COVID-19, and heating and cooling degree days (**Equation 2**). The

resulting monthly use-per-customer forecast is combined with the annual customer count forecast for a monthly forecast of residential energy deliveries.

Equation 1. Residential energy deliveries

$$kWh_{res} = UPC_{res} * CC_{res}$$

Where:

- UPC = Use-per-customer
- CC = Customer count

Equation 2. Residential use-per-customer

$$UPC_{res,t} = \sum_{k=0}^{11}(\beta_k\, Month_k + \alpha_k Trend_k) + \beta_{12} HDD60 + \beta_{13} CDD65 + \beta_{14} COVID\ Indicator_t + \beta_{15} UPC_{res,t-1} + \varepsilon_t$$

Where:

- HDD60 = Heating degree day with 60° F set point
- CDD65 = Cooling degree day with 65° F set point
- Trend = Numerical variable that increases by 1 each year
- COVID Indicator = Indicator variable between 0 and 1
- ε_t= error term

Equation 3. Residential customer count

$$\Delta CC_{res,t} = \beta_0 + \beta_1 * \Delta POP_{or} + \beta_2 \sum_{n=1}^{12} \frac{CC_{res.n}}{\sum_{n=1}^{12} n} + \varepsilon_t$$

Where:

- $\Delta y = y_t - y_{t-1}$ representing a first-order difference
- POP_{OR} = Oregon Population
- ε_t= error term

Commercial model

The commercial energy deliveries model, shown in **Equation 4**, is a monthly model that establishes a relationship between commercial energy deliveries and Oregon's Total Non-Farm employment, COVID-19, and heating and cooling degree days.

Equation 4. Commercial energy deliveries

$$kWh_{com,t} = \sum_{k=0}^{11} \beta_k \, Month_k + \beta_{12} HDD50 + \beta_{13} CDD60 + \beta_{14} COVID\ Indicator_t + \beta_{15}\, OENTNA + \beta_{16}\, kWh_{com,t-1} + \varepsilon_t$$

Where:

- HDD50= Heating degree day with 50° F set point
- CDD60 = Cooling degree day with 60° F set point
- COVID Indicator = Indicator variable between 0 and 1
- OENTNA = Oregon's Total Non-Farm employment
- ε_t = error term

Industrial model

The annual industrial model includes Oregon's Total Personal Income as a driver of energy deliveries (**Equation 5**).

Equation 5. Industrial energy deliveries

$$\Delta kWh_{ind,t} = \beta_0 + \beta_1 X \Delta Personal\ Income + \beta_2 \sum_{n=1}^{12} \frac{kWh_{ind,n}}{\sum_{n=1}^{12} n} + \varepsilon_t$$

Where:

- $\Delta y = y_t - y_{t-1}$ representing a first-order difference
- Personal Income= Oregon's Total Personal Income
- ε_t= error term

D.1.5 Peak model

The peak models, shown in **Equation 6 and 7. Peak Demand**, are a monthly seasonal model that relates the single-hour peak demand of PGE's net system (in MW) to average monthly demand (in MWa) and weather variables. The models consider the impact of heating and cooling degree days (HDD and CDD), as well as the summer model, which accounts for the growing saturation of air conditioning in the home in PGE's service area. Both models include the previous day's temperature impacts by using cooling or heating degree days, and the winter model includes wind speed.

Equation 6 and 7. Peak Demand

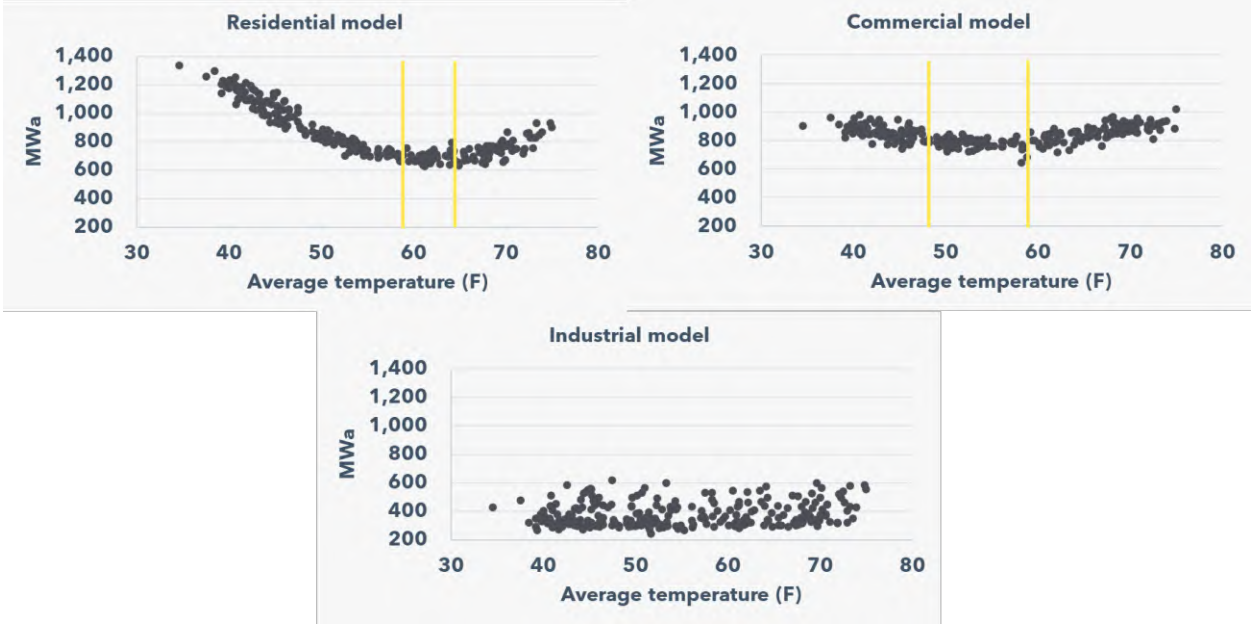
$$MW_{summer,t} = \beta_1 PKDAYCDD + \beta_2 PDCDD + \frac{\beta_3 ACSAT * NRC1_t}{1000} + \beta_4 CycleMA_t + \beta_5 CDD65 + \beta_6 May + \beta_7 Jun + \beta_8 Jul + \beta_9 Aug + \beta_{10} Sep + \beta_{11} Weekend + \varepsilon_t$$

$$MW_{winter,t} = \beta_1 PKDAYHDD + \beta_2 PDHDD + \beta_3 PKDAYWIND + \beta_4 CycleMA_t + \beta_5 HDD60 + \beta_6 Oct + \beta_7 Nov + \beta_8 Dec + \beta_9 Jan + \beta_{10} Feb + \beta_{11} Mar + \beta_{12} Weekend + \beta_{13} STEP0811 + \varepsilon_t$$

Where:

- MWa = Average monthly demand
- PKDAYCDD = CDD with 65° F set point on the day the peak occurred
- PDCDD = CDD with 65° F set point on the day before the day the peak occurred
- NRC1 = Count of residential customers
- ACSAT = Percentage of households with air conditioning
- CycleMA = Twelve months moving average of total monthly usage
- PKDAYHDD = HDD with 65° F set point on the day the peak occurred
- PDCDD = HDD with 65° F set point on the day before the day the peak occurred
- PKDAYWIND = Average daily wind speed on the day the peak occurred
- STEP0811 = An indicator variable beginning in November 2008
- ε_t = error term

Figure 120. Weather sensitivity of energy deliveries to (a) the residential class, (b) the commercial class, and (c) the industrial class



D.1.6 Probabilistic loads

All forecasts are subject to uncertainty, including uncertainties associated with forecasts of the input variables and the complexity of the estimated relationships with those variables. Some of these uncertainties can be characterized quantitatively using model parameters.

The single most important driver of load variability is the weather. Residential and small commercial loads are particularly sensitive to the weather due to heating and cooling loads. Weather is known to be highly variable from one year to the next. PGE addresses the stochastic risk in the load forecast associated with weather, analyzing 30 years of weather variability in its Resource Adequacy model, described in **Chapter 6, Resource needs.**

Two sources of uncertainty characterized using the output statistics of the regression models described previously are model uncertainty and coefficient uncertainty. Model uncertainty is the standard error of the regression or a reflection of how the model performs over the period of data used to inform the model. Coefficient uncertainty is the standard error associated with the estimated coefficient, which defines the relationship between the dependent and driver variables.

EViews, a statistical package used primarily for time-series oriented econometric analysis, and also the software package PGE uses to conduct its load forecast, was used to run stochastic simulations that combine model uncertainty and coefficient uncertainty to create confidence bands around the base case forecast. During simulation runs, coefficients are randomly

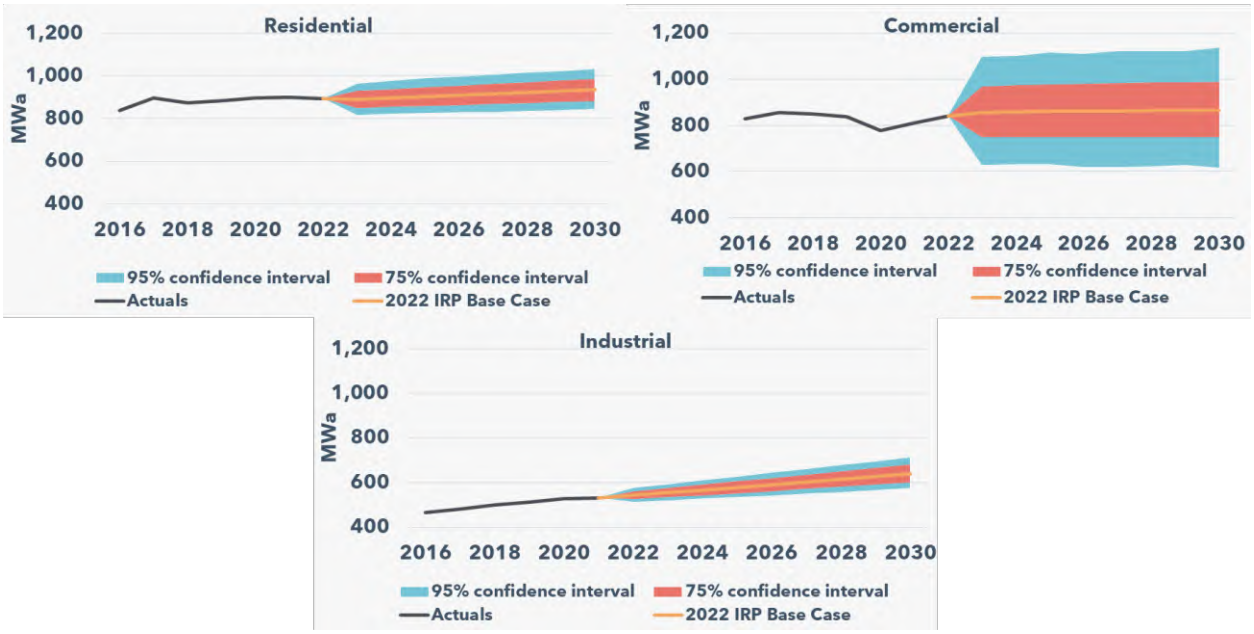
varied along with residuals, and the errors are quantified and used to obtain confidence intervals. Over 10 thousand simulations were run for each of the long-term regression models.

Figure 121 shows the 75 and 95 percent confidence bounds on the three energy deliveries models.

Another category of uncertainty relates to the driver variables used in the regression models. Uncertainties in the forecast of the economic driver variables are considered by scenario analysis, described further in **Chapter 6, Resource needs**.

Other uncertainties not quantified by this approach yet worth mentioning relate to variables excluded from the models and the estimation periods of the models. For example, specific large load might cause shifts in load that cannot be precisely timed by a driver-based model. A model is, by design, a simplification of reality. The interdependencies of energy deliveries are complex and widespread across the macroeconomy. The benefits and uncertainties of different variable selection and estimation periods are weighed during the model development and evaluation process. Drivers which may impact loads outside of this modeling process may be considered in scenario analysis outside of the modeled uncertainties.

Figure 121. Confidence interval on the net system residential (left), commercial (right), and industrial (low) energy deliveries models



D.2 Results

Results of the top-down econometric models described previously are combined with explicit forecasts for EE, EV, and behind-the-meter solar and storage to arrive at the total load scenarios shown in the following tables. These load forecasts do not include long-term direct access loads, consistent with Guideline 9.[439] This section provides low, reference, and high forecasts for Net System Load by residential, commercial, and industrial customers. Net System Load includes both cost-of-service supply customers, long-term direct access customers and new load direct access customers.

D.2.1 Energy load forecasts

Table 100 summarizes the load forecast scenarios for energy deliveries (in MWa) at the bus bar.[440]

Table 101, **Table 102**, and **Table 103** provide the annual forecasts for the reference, low, and high scenarios. For these tables, note that passive DER only captures the forecasts for generation from distributed PVs.

Table 100. Load forecast scenarios in MWa[441]

	Low Need			Reference Case			High Need		
	2023	2043	AAGR	2023	2043	AAGR	2023	2043	AAGR
Top-down Load Forecast	2,351	3,644	2%	2,365	3,970	3%	2,378	4,276	3%
Base Load Forecast	2,320	3,054	1%	2,334	3,407	2%	2,347	3,731	0
Energy Efficiency	-31	-590	0	-31	-563	0	-31	-546	17%
Rooftop PV	-1	-81	28%	-1	-50	28%	-1	-28	22%
Building Electrification	4	86	17%	4	87	17%	4	124	20%

[439] Order No. 07-002 at 19, see Guideline 9, as amended by Order No. 07-047 at Appendix A, p.6
[440] As mentioned previously, the load forecasts in this section do not include long-term direct access loads.
[441] The base load forecast is the top-down load forecast adjusted to exclude the impacts of the cost-effective deployable EE savings and the assumptions for the embedded distributed PV generation and electric vehicle load. The EE savings are cumulative values adjusted for line losses and intra-year deployment beginning in 2022. Note that in this and the following tables the AAGR is not calculated because savings before 2020 are not reported in these values.

	Low Need			Reference Case			High Need		
	2023	2043	AAGR	2023	2043	AAGR	2023	2043	AAGR
Transportation Electrification	13	372	18%	15	504	20%	16	590	20%
Total Load Forecast	2,305	2,841	1%	2,321	3,385	2%	2,336	3,870	3%

Table 101. Reference case load scenario with layers, MWa

Year	(a) Base load	(b) Energy Efficiency	(c) Transportation Electrification	(d) Rooftop PV	(e) Building Electrification	(f) = (a) + (b) + (c) + (d) + (e) Total Load
2023	2,334	-31	15	-1	4	2,321
2024	2,402	-61	21	-1	7	2,367
2025	2,463	-91	28	-3	10	2,407
2026	2,530	-121	38	-5	13	2,455
2027	2,594	-151	48	-8	17	2,500
2028	2,649	-181	60	-12	20	2,535
2029	2,703	-214	73	-18	23	2,567
2030	2,759	-247	91	-25	27	2,605
2031	2,817	-282	115	-31	31	2,650
2032	2,875	-316	139	-37	35	2,696
2033	2,931	-348	166	-41	40	2,747
2034	2,986	-378	196	-42	44	2,804
2035	3,040	-408	224	-43	48	2,861
2036	3,093	-435	266	-44	53	2,932
2037	3,143	-460	296	-45	57	2,992
2038	3,192	-483	327	-45	61	3,052
2039	3,237	-502	365	-46	66	3,120
2040	3,280	-518	405	-47	72	3,192

Year	(a) Base load	(b) Energy Efficiency	(c) Transportation Electrification	(d) Rooftop PV	(e) Building Electrification	(f) = (a) + (b) + (c) + (d) + (e) Total Load
2041	3,323	-533	440	-48	77	3,258
2042	3,361	-545	457	-49	80	3,304
2043	3,407	-563	504	-50	87	3,385
Average annual growth rate	2%	N/A	20%	28%	17%	2%

Table 102. Low Case load scenario with layers, MWa

Year	(a) Base load	(b) Energy Efficiency	(c) Transportation Electrification	(d) Rooftop PV	(e) Building Electrification	(f) = (a) + (b) + (c) + (d) + (e) Total Load
2023	2,320	-31	13	-1	4	2,305
2024	2,373	-61	18	-2	7	2,336
2025	2,419	-91	24	-4	10	2,358
2026	2,471	-121	31	-7	13	2,388
2027	2,520	-152	38	-11	17	2,412
2028	2,558	-184	46	-16	20	2,425
2029	2,596	-217	55	-23	23	2,434
2030	2,637	-252	68	-33	27	2,446
2031	2,678	-288	84	-43	31	2,463
2032	2,719	-323	100	-52	35	2,479
2033	2,758	-357	118	-58	39	2,501
2034	2,796	-389	138	-60	44	2,529
2035	2,833	-420	157	-63	48	2,555
2036	2,869	-449	185	-65	53	2,593
2037	2,901	-476	207	-67	57	2,622
2038	2,932	-502	230	-69	61	2,652

Year	(a) Base load	(b) Energy Efficiency	(c) Transportation Electrification	(d) Rooftop PV	(e) Building Electrification	(f) = (a) + (b) + (c) + (d) + (e) Total Load
2039	2,959	-523	257	-72	66	2,688
2040	2,984	-542	288	-75	72	2,728
2041	3,007	-558	317	-77	77	2,767
2042	3,027	-570	333	-79	80	2,791
2043	3,054	-590	372	-81	86	2,841
Average annual growth rate	1%	N/A	18%	28%	17%	1%

Table 103. High Case load scenario with layers, MWa

Year	(a) Base load	(b) Energy Efficiency	(c) Transportation Electrification	(d) Rooftop PV	(e) Building Electrification	(f) = (a) + (b) + (c) + (d) + (e) Total Load
2023	2,347	-31	16	-1	4	2,336
2024	2,428	-61	24	-1	7	2,397
2025	2,503	-91	33	-1	11	2,454
2026	2,585	-121	44	-2	15	2,522
2027	2,664	-150	56	-2	20	2,587
2028	2,733	-180	71	-3	24	2,645
2029	2,802	-212	88	-3	29	2,704
2030	2,873	-243	110	-3	34	2,771
2031	2,946	-276	140	-4	40	2,846
2032	3,019	-309	172	-5	46	2,923
2033	3,091	-340	207	-5	52	3,005
2034	3,163	-369	248	-6	58	3,094
2035	3,233	-396	287	-7	64	3,181
2036	3,302	-421	340	-8	72	3,285

Year	(a) Base load	(b) Energy Efficiency	(c) Transportation Electrification	(d) Rooftop PV	(e) Building Electrification	(f) = (a) + (b) + (c) + (d) + (e) Total Load
2037	3,368	-445	378	-10	78	3,370
2038	3,433	-467	415	-12	85	3,454
2039	3,494	-485	457	-15	92	3,544
2040	3,553	-502	499	-18	101	3,635
2041	3,613	-517	534	-21	109	3,718
2042	3,668	-528	544	-25	114	3,774
2043	3,731	-546	590	-28	124	3,870
Average annual growth rate	2%	N/A	20%	22%	20%	3%

D.2.2 Peak load forecasts

Table 104 provides the seasonal peak loads for each year and Need Future.[442] These tables reflect total load values; the top-down econometric forecast combined with the forecasts for EVs and building electrification. This forecast includes costs effective energy efficiency but does not include the impacts of passive or active demand response programs. The values in this table are reflective of the loads used in the Sequoia model, which has 30-years (1992-2021) of weather variation included (median peak loads are shown).

Table 104. Peak load forecast by Need Future and season, MW

Year	Low Need		Reference Need		High Need	
	Summer	Winter	Summer	Winter	Summer	Winter
2023	3,712	3,510	3,726	3,525	3,740	3,541
2024	3,746	3,547	3,776	3,580	3,805	3,613
2025	3,781	3,583	3,828	3,635	3,874	3,689
2026	3,822	3,626	3,888	3,699	3,953	3,774

[442] As mentioned previously, the load forecasts in the section do not include long-term direct access loads.

Year	Low Need		Reference Need		High Need	
	Summer	Winter	Summer	Winter	Summer	Winter
2027	3,861	3,668	3,948	3,766	4,032	3,864
2028	3,890	3,706	4,001	3,831	4,105	3,954
2029	3,924	3,734	4,061	3,885	4,188	4,036
2030	3,960	3,773	4,124	3,954	4,277	4,136
2031	4,002	3,814	4,195	4,030	4,376	4,244
2032	4,043	3,861	4,269	4,111	4,481	4,363
2033	4,095	3,908	4,355	4,198	4,602	4,492
2034	4,145	3,964	4,442	4,292	4,729	4,632
2035	4,200	4,020	4,535	4,389	4,860	4,773
2036	4,256	4,081	4,630	4,493	4,994	4,921
2037	4,319	4,139	4,732	4,592	5,130	5,058
2038	4,380	4,203	4,830	4,697	5,259	5,198
2039	4,442	4,267	4,930	4,801	5,383	5,329
2040	4,506	4,336	5,027	4,904	5,500	5,456
2041	4,576	4,402	5,128	5,002	5,616	5,573
2042	4,643	4,472	5,223	5,102	5,723	5,689
2043	4,709	4,540	5,316	5,197	5,824	5,797
Annual average growth rate	1.2%	1.3%	1.8%	2.0%	2.2%	2.5%

D.3 Net system load

Net System Load includes both cost-of-service supply customers and direct access customers. While Net System Load is not used in the IRP need assessments or portfolio

analysis, the information in this section is provided for reference as it reflects the level of disaggregation at which the load forecast analysis occurs.

Table 105, **Table 106**, and **Table 107** provide the reference, low, and high econometric load forecasts for Net System Load in MWa at the bus bar by class. The commercial class includes street and highway lighting, and the industrial class consists of both transmission and primary-level customers. The high and low scenarios capture high and low growth conditions and +/- 1 standard deviation of uncertainty from the regression model parameters. These forecasts do not include the impacts of the explicit forecasts for Energy Vehicles (EVs), Distributed Energy Resources (DERs), or additional Energy Efficiency (EE) savings beyond Energy Trust's projections.

Table 105. Econometric Net System Load with reference growth conditions, MWa

Year	Residential	Commercial	Industrial	Total
2022	933	802	503	2,239
2023	922	815	566	2,303
2024	918	808	615	2,341
2025	914	801	657	2,372
2026	913	794	703	2,409
2027	915	786	743	2,444
2028	921	786	760	2,467
2029	928	788	772	2,489
2030	935	790	787	2,512
2031	942	791	802	2,535
2032	949	792	818	2,559
2033	956	793	834	2,583
2034	963	795	850	2,607
2035	970	796	866	2,632
2036	977	797	883	2,657
2037	984	798	900	2,683
2038	991	800	918	2,709
2039	999	801	936	2,735

Year	Residential	Commercial	Industrial	Total
2040	1,006	802	954	2,762
2041	1,013	803	972	2,789
2042	1,021	805	991	2,817
2043	1,028	806	1,010	2,845
2044	1,036	807	1,030	2,873
2045	1,043	809	1,050	2,902
2046	1,051	810	1,071	2,932
2047	1,059	811	1,091	2,961
2048	1,067	812	1,113	2,992
2049	1,075	814	1,134	3,022
2050	1,082	815	1,156	3,054
Average annual growth rate	0.5%	0.1%	3.0%	1.1%

Table 106. Econometric Net System Load with low growth conditions, MWa

Year	Residential	Commercial	Industrial	Total
2022	933	802	503	2,239
2023	918	812	559	2,289
2024	910	802	601	2,312
2025	902	792	634	2,329
2026	897	782	672	2,351
2027	895	771	703	2,369
2028	897	769	711	2,376
2029	901	768	713	2,382
2030	903	766	719	2,388
2031	906	764	724	2,395
2032	909	763	730	2,401

Year	Residential	Commercial	Industrial	Total
2033	912	761	736	2,408
2034	914	759	742	2,415
2035	917	758	748	2,423
2036	920	756	754	2,430
2037	923	754	760	2,438
2038	926	753	767	2,445
2039	929	751	773	2,453
2040	932	749	780	2,461
2041	935	748	787	2,470
2042	938	746	794	2,478
2043	941	744	802	2,487
2044	944	742	809	2,495
2045	947	741	817	2,504
2046	950	739	824	2,514
2047	953	737	832	2,523
2048	957	736	841	2,533
2049	960	734	849	2,543
2050	963	732	858	2,553
Average annual growth rate	0.1%	-0.3%	1.9%	0.5%

Table 107. Econometric Net System Load with high growth conditions, MWa

Year	Residential	Commercial	Industrial	Total
2022	926	813	628	2,367
2023	927	808	677	2,412
2024	931	803	731	2,464
2025	937	797	779	2,513

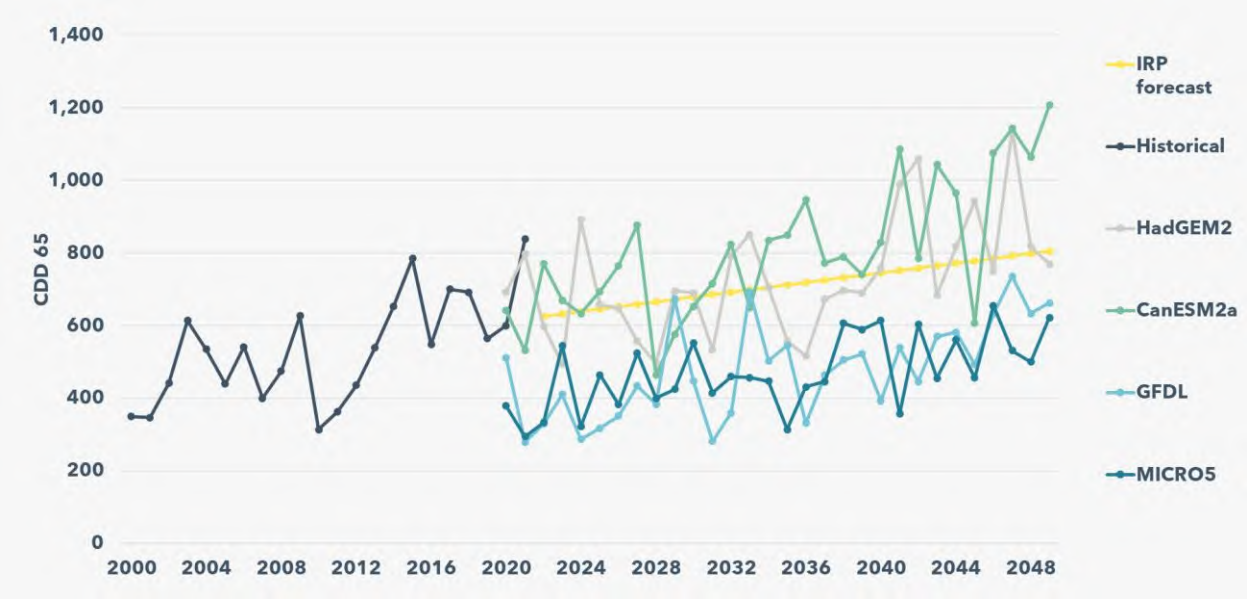
Year	Residential	Commercial	Industrial	Total
2026	947	800	804	2,552
2027	959	804	824	2,588
2028	971	808	848	2,626
2029	982	811	871	2,665
2030	994	815	895	2,703
2031	1,005	818	919	2,743
2032	1,017	822	944	2,782
2033	1,029	825	969	2,823
2034	1,040	829	994	2,863
2035	1,052	832	1,020	2,904
2036	1,064	836	1,046	2,946
2037	1,076	839	1,072	2,988
2038	1,089	843	1,099	3,031
2039	1,101	846	1,126	3,074
2040	1,113	850	1,154	3,117
2041	1,126	854	1,182	3,161
2042	1,138	857	1,210	3,205
2043	1,151	861	1,239	3,250
2044	1,164	864	1,268	3,296
2045	1,176	868	1,297	3,342
2046	1,189	871	1,327	3,388
2047	1,202	875	1,358	3,435
2048	1,216	879	1,388	3,482
2049	933	802	503	2,239
2050	926	817	572	2,316
Average annual growth rate	1.0%	0.3%	3.7%	1.6%

D.4 Climate change model data and the IRP load forecast

The temperature data used by the econometric load forecasting model have historical climate change trends built into them. In general, this increases cooling-degree days going forward and decreases heating-degree days.[443] The IRP compares these historical trends with climate model outputs to see how similar they are. The climate model data used in the comparison are from the River Management Joint Operating Committee (RMJOC) studies that use data from the Intergovernmental Panel on Climate Change (IPCC). The four models used in the comparison were selected by the RMJOC for streamflow analysis and were recommended for the IRP analysis by Creative Renewable Solutions.[444]

Figure 122 compares cooling degree days (CDD 65) annually between the historical data, the trend data used in the IRP econometric forecast, and the climate model outputs. Historical data and the econometric load forecast data are in gray. There is an upward trend in the econometric load forecast data. An upward trend in CDD 65 indicates warming temperatures in summer months and more demand for mechanical cooling (air conditioning). The figure data from the four climate models are in color and trend upwards, too.

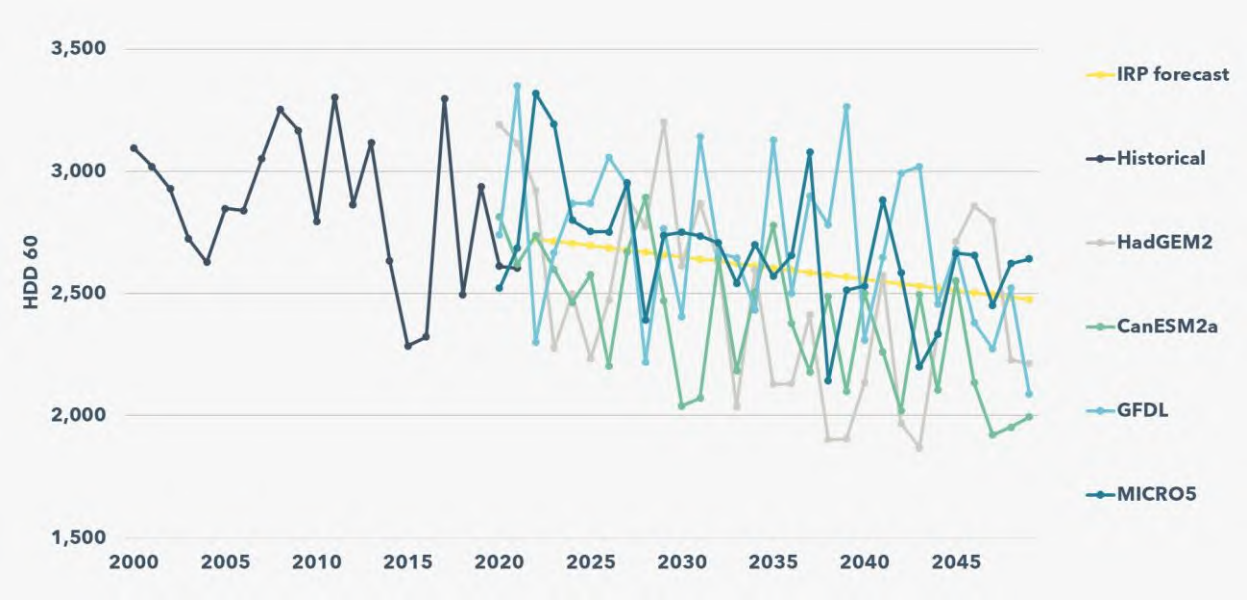
Figure 122. Annual cooling degree day forecasts



In **Figure 122**, the econometric load forecast CDD 65 inputs (in gray) trend inside the range of the climate change model data (in color). This indicates that the warming trend approach used by the econometric load forecasting model somewhat comports with the data from the climate change models.

Figure 123 compares heating degree days from historical data (in gray), the IRP econometric load forecast (in gray), and the climate change models (in color). All datasets show a decreasing trend in heating degree days on a yearly basis. This indicates warming temperatures in winter months, and a decreased need for heating.

Figure 123. Annual heating degree day forecasts



In **Figure 123**, the econometric load forecast HDD 65 inputs (in gray) trend inside the range of the climate change model data on an annual level. On a monthly level however, the econometric load forecast trend in December and February is flat, whereas the climate models have a declining trend (not shown).

Based on the observation that the annual HDD and CDD data used in the econometric load forecast are mostly in the range of the climate model data, PGE decided to stay with the warming trend approach for the 2023 IRP. In future planning work PGE will continue to update the trend approach while exploring using climate change model data.

[443] Cooling degree days define days that average higher than a certain temperature, often 65 degrees F. An increase in cooling degree days indicates warming temperatures (and more need for air conditioning). Heating degree days define days that average less than a certain temperature, often 60 degrees F. A reduction in heating degree days indicates warming temperatures (and less need for heating).
[444] Additional climate change data are available at: https://www.bpa.gov/energy-and-services/power/climate-change-fcrps

Appendix E. Existing and contracted resources

PGE operates a diverse portfolio of resources to meet PGE's system energy and capacity needs. The appendix describes existing resources and resources with executed agreements that may not yet be in service.

E.1 Existing resources

E.1.1 Thermal resources

The technology and size characteristics for each plant are provided in the following sections. Note that these descriptions and capacity (in MW) represent the annual average net capacity of the power plant, which includes any duct-firing capabilities and excludes any de-rates for maintenance or forced outage rates. In contrast, energy (in MWa) represents the annual average availability after projected forced outages and maintenance. Also, note that the capacity of combined-cycle combustion turbines (CCCTs) varies across seasons as turbine operations are more sensitive to temperature changes. When the temperature is high during the summer, the turbines provide less capacity as operations are affected, while other steam technologies have more consistent capacity regardless of temperature change. In the following sections, each thermal resource is described in greater detail. The annual average energy availability, MWa, for each resource is for the period between 2023 to 2050, unless noted otherwise.

Carty

Carty is a CCCT resource built adjacent to PGE's Boardman coal plant in Boardman, Oregon. The plant became operational in 2016. It provides 391 MW of annual average capacity. The plant has a highly efficient Mitsubishi Heavy Industries (MHI) G-class combustion turbine. The annual average energy availability is 369 MWa. Finally, the plant has 47 MW of duct firing for capacity needs.

Coyote Springs

Coyote Springs is a gas fired CCCT facility in Boardman, Oregon, which became operational in 1995. Coyote Springs has an annual average capacity of 252 MW (including 2 MW of additional capacity when operating an auxiliary boiler to supply steam-to-steam customers) and an annual average energy availability of 228 MWa.

Port Westward 1

Port Westward 1 (PW1) reached commercial operation in June 2007. This CCCT plant is in Clatskanie, Oregon. The plant supplies approximately 411 MW of annual average capacity (including approximately 17 MW of duct firing) and has an annual average energy availability of 367 MWa.

Beaver

Beaver is a CCCT facility in Clatskanie, Oregon. PGE placed the plant into service in 1976. Beaver has an annual average capacity of 486 MW. The six combustion turbines (CTs) operate primarily on natural gas but can also be fueled with No. 2 diesel fuel oil via on-site tank storage. The CTs each have heat recovery steam generators that connect to a single steam turbine, allowing PGE to operate the plant either in simple-cycle mode or in combined–cycle mode. A separate simple cycle unit, Beaver 8, was added to the site in 2001 and has an annual average capacity of 23 MW.

Port Westward 2

Port Westward 2 (PW2) is in Clatskanie, OR, adjacent to PGE's PW1 plant. PW2 began commercial operations in December 2014. It comprises 12 natural gas-fired reciprocating engines with an annual average capacity of approximately 225 MW. In addition to providing peak capacity, the modular configuration offers a wide range of dispatch flexibility for wind, load following, and additional energy value.

Boardman

Boardman came into service in 1980 and went offline on October 15, 2020. It was decommissioned and demolished on September 15, 2022. Boardman was a coal plant in Boardman, Oregon, with an annual capacity of approximately 575 MW when it was operational.

Colstrip

Colstrip is a four-unit coal-fired plant located in Colstrip, Montana, with coal transported by conveyor belt directly from the on-site mine to the boiler. Colstrip units 1 and 2 became operational in 1975 and 1976, respectively. The units were owned by Talen Energy and Puget Sound Energy and were shut down in 2019.

PGE owns 20 percent of Colstrip units 3 and 4, representing approximately 296 MW (or 20 percent of the combined units 3 and 4) of annual average capacity. The average annual energy availability for PGE's share of Colstrip Units 3 and 4 is 262 MWa for the remaining operating period, 2023-2029. PGE has plans to discontinue usage of and exit its 20 percent ownership of the Colstrip plant by the end of 2029.

E.1.2 Hydropower plants

PGE owns and operates eight hydroelectric plants on the Deschutes, Clackamas, and Willamette River systems. Pelton and Round Butte plants have reservoir storage capability, while the remaining plants have limited ability to store water and shape energy. These plants are operated as run-of-river projects.

Pelton-Round Butte hydropower project

PGE operates the Pelton and Round Butte plants on the Deschutes River near Madras, Oregon. These plants provide peaking and load-following capabilities. A portion of PGE's hydropower capacity also contributes to meeting the required spinning and supplemental (non-spin) operating reserve requirements, which are necessary for responding to system contingencies.

In an average hydro condition, the plants have a combined annual average dependable capacity of approximately 447 MW and an expected annual energy production of 165 MWa. PGE owns 50.1 percent of each plant (approximately 224 MW, 82 MWa), with the remaining share owned by the Confederated Tribes of the Warm Springs Reservation (Tribes). The Tribes agreed to sell all their output to PGE through 2040. See **Section E.2.2, Pelton, Round Butte, and the Re-regulating dam**, for more details on the agreement.

Clackamas River hydropower projects

PGE owns and operates six plants on the Clackamas River system. Under average hydropower generation conditions, the plants have the following average annual capacities:

- Timothy Powerhouse, 1.2 MW (OR RPS compliant)[445]
- Harriet Powerhouse, 0.5MW
- Oak Grove, 27MW
- North Fork, 27 MW (OR RPS compliant)
- Faraday, 27 MW (OR RPS compliant)
- River Mill, 15 MW (OR RPS compliant)

Under average hydro conditions, the aggregated expected annual energy production from each of these projects is 84 MWa.

Willamette Falls hydropower project

PGE owns and operates the Sullivan plant on the Willamette River at Willamette Falls. Under average hydropower generation conditions, the plant's nameplate capacity is 14 MW, and the expected annual energy production is 14 MWa.

E.1.3 Wind and Solar plants

Biglow Canyon

The Biglow Canyon Wind Farm was completed in three phases in 2007, 2009, and 2010. The wind farm in the lower Columbia River Gorge near Wasco, Oregon, has a total nameplate generating capacity of 450 MW. Based on an expected capacity factor of approximately 26 percent, PGE estimates Biglow's annual average energy production at 118 MWa. Biglow's generation is RPS compliant as it is renewable energy that contributes towards the RPS requirement of being 50 percent renewable by 2040.

[445] The Oregon Renewable Portfolio Standard (RPS) sets a requirement for how much of the electricity used in Oregon must come from renewable resources. The passage of Oregon Senate Bill 1547 increased Oregon's Renewable Portfolio Standard requirement to 50 percent renewables by 2040. RPS is discussed in **Section 6.7, RPS need**.

Clearwater wind

The Clearwater wind farm will span Rosebud, Garfield, and Custer counties in Montana. It is a 775 MW wind site in Montana being developed by NextEra Energy Resources, LLC. PGE will procure 311 MW of energy from the Clearwater Wind project, scheduled to be operational by December 31, 2023. PGE's power from Clearwater will be generated by 112 General Electric wind turbines. The Clearwater project is expected to deliver higher levels of production during the winter and summer. The power will be served to PGE customers through existing transmission on the Northwestern Energy and Bonneville Power Administration (BPA) systems.

Tucannon River wind farm

Located near Dayton, Washington, PGE's Tucannon River Wind Farm (Tucannon) consists of 116 2.3- MW Siemens wind turbine generators with a total nameplate capacity of 267 MW. The plant's 35 percent expected capacity factor results in an expected output of 94 MWa. The project was completed and became operational in December 2014. Generation from Tucannon is Renewable Portfolio Standard (RPS) compliant RPS compliant as it is a renewable energy that contributes towards the RPS requirement of being 50 percent renewable by 2040.

Wheatridge renewable energy facility

In 2019, PGE entered into agreements with NextEra for the Wheatridge Renewable Energy Facility in Morrow County, Oregon. The facility consists of 300 MW of wind, 50 MW of solar, and 30 MW of battery storage. The wind portion of the facility entered service at the end of 2021, and the solar and storage components began service in 2022. PGE owns 100 MW of the wind resources and entered into a long-term purchase agreement with NextEra for the remainder of the project.

E.1.4 Energy storage

HB 2193 Energy storage

In compliance with HB 2193, PGE submitted its fourth annual report on the progress of its energy storage proposal on September 2, 2022.[446] The report provides evaluation and progress updates of the energy storages: Baldock, Coffee Creek, Microgrid pilot, Port Westward 2 (PW2), Residential Storage pilot (called the "Smart Battery Pilot"), and the controls for the energy storage systems.

As of September 2, 2022, the energy storages have the following status:[447]

- Baldock, 2 MW, undetermined
- Coffee Creek, 17-20 MW, COD in 2024
- Microgrid pilot (Beaverton Public Safety Center), 0.25 MW, operating
- Microgrid pilot (ARC), 0.5 MW, COD in Q1 2023
- Port Westward 2, 5 MW, operating
- Smart Battery Pilot, active program

Salem smart power center (SSPC)

As part of the Pacific Northwest Smart Grid Demonstration, PGE invested approximately $6 million, which was matched by Department of Energy (DOE) and other partner's three-to-one investment, to deploy a 5-MW (1.25 MWh) Li-ion battery inverter system at the Salem Smart Power Center (SSPC). This advanced Li-ion battery system provides uninterrupted power, reactive power (value at risk (VAR) support), and ancillary services. It can also be configured for energy storage for small-scale ancillary services in firming and shaping variable resources, such as solar and wind generation. The SSPC fulfilled a regional and visionary transactive control demonstration project that was co-funded by the US DOE under the American Recovery and Reinvestment Act. The primary contractor was Battelle, with PGE serving as a subcontractor on the project.

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[446] H.B. 2193, 78TH Oregon Legislative Assembly, (2015) https://olis.oregonlegislature.gov/liz/2015R1/Downloads/MeasureDocument/HB2193

[447] A full evaluation of the energy storage updates can be found in PGE UM 1856 PGE Draft Storage Potential Evaluation 2022 Annual Energy Storage Update, September 2, 2022. Available at: https://edocs.puc.state.or.us/efdocs/HAD/um1856had133540.pdf

PGE formally launched the project in 2010 and became fully operative in May 2013. When the demonstration concluded in January 2015, PGE confirmed that project assets are responsive to transactive control. Since the battery inverter system continues to operate as part of PGE's transmission and distribution system. It currently provides a routine automatic under-frequency response in compliance with North American Electric Reliability Corporation (NERC) BAL-003-1.

E.2 Contracted resources

Contracts provide a diversity of energy and capacity to PGE's resource portfolio. This section summarizes the contracts included in this IRP. The hydropower capacity value in this section represents annual average dependable values, not plant capacities.

E.2.1 Mid-Columbia and Canadian entitlement allocation

PGE has a project share of some hydropower facilities on the mid-section of the Columbia River (Mid-C). This means that PGE has proportional rights to the project reservoirs, allowing for energy shaping across hours and days. PGE can utilize these resources to provide ancillary services, including regulation and spinning reserves.

Wells

The Wells Dam is located downstream of Chief Joseph and was completed in 1967. The 10-turbine facility is operated by the Douglas County PUD No. 1 (Douglas Public Utility District). Upon the contractual expiration on August 31, 2018, and per Oregon Public Utility Commission (OPUC) Order No. 14-415, PGE sought to renew all or a portion of the Wells contract if a cost-effective agreement could be reached. PGE reached a new agreement with Douglas PUD for projects through September 30, 2028.

Douglas Country PUD Contract

PGE and Douglas County Public Utility District No.1 signed a five-year power purchase agreement to supply PGE customers with up to 160 MW of additional capacity from the Wells Hydroelectric Project on the Columbia River north of Wenatchee, Washington. The five-year agreement began in January 2021.

Priest Rapids project

The Priest Rapids Project is located downstream of Rock Island and consists of the Wanapum Dam (10 units, completed in 1964) and the Priest Rapids Dam (10 units, completed in 1961). Both facilities are operated by the Grant County Public Utility District (PUD) No. 2 (Grant PUD). PGE has contractual rights to approximately 8.62 percent of each facility through the spring of 2052. The combined annual average dependable capacity of PGE's share is approximately 131 MW, and the expected annual average energy under average hydro conditions is 44 MWa. Both values are prior to PGE's associated Canadian Entitlement obligations as discussed in the following section.

Canadian entitlement allocation

An agreement was entered between the US and Canada in which the US shares a portion of the generation benefits from the Columbia River storage reservoirs in Canada.[448] This agreement for the entitlement benefits ended in 2003 but was extended to 2024. PGE's share of Mid-C projects (Wells, Wanapum, and Priest Rapids) are subject to the Canadian Entitlement Allocation Extension (CEAE) obligations. For the IRP, PGE reflects the Columbia River Treaty by assuming that the CEAE renews after 2024 (or that the net effect of any operating changes after the expiration is approximately the same as if the agreement is renewed). PGE models this as the delivery of on-peak power to Canada.

E.2.2 Pelton, Round Butte, and the Re-regulating dam

As discussed in **Section E.1.2, Hydropower plants**, the Confederated Tribes of the Warm Springs Reservation (Tribes) have a 33.33-percent ownership share of the Pelton and Round Butte plants which included contractual rights to increase their ownership to 49.99 percent at the end of 2021. The Tribes also own 100 percent of the associated Re-regulating Dam (Re-reg Dam, 10 MW, 10 MWa), which PGE operates. PGE and the Tribes entered into an agreement for PGE to purchase the Tribes' shares of Pelton, Round Butte, and the Re-reg Dam through 2040.

[448] The Columbia River Treaty, ratified in 1964, required the U.S. to deliver one-half of three storage dams to Canada under the Canadian Entitlement Allocation Agreements (CEAA).
Canadian Entitlement Allocation Extension Agreements - April 29, 1997 (bpa.gov)

E.2.3 Wheatridge Energy Facility

PGE entered into agreements with Next Era for the Wheatridge Energy Facility, including long-term purchase agreements for 200 MW of wind, 50 MW of solar, and 30 MW of battery storage. The wind portion of the facility began service at the end of 2020, and the solar and storage components began service at the beginning of 2021.

E.2.4 Bilateral capacity agreements

Bilateral negotiations for capacity resulted in three agreements signed in early 2018.

Bonneville Power Administration (BPA)

PGE executed two agreements with BPA, each having 100 MW of annual capacity, with a five-year term beginning in 2021.

Avangrid renewables

PGE executed an agreement with Avangrid Renewables for 100 MW of seasonal peak capacity during summer and winter, with a five-year term beginning in July 2019.

E.2.5 Additional contracts

Table 108 summarizes additional contract resources in PGE's existing portfolio excluding qualifying facility (QF) agreements, which are covered in **Section E.2.6, Qualifying facility contracts**.

Table 108. Additional contracts by technology, MW[449]

	2023	2024	2025	2030	2035	2040	2043
Solar	311	397	404	453	453	93	93
Hydropower	875	875	875	36	-	-	-
Wind	99	99	99	75	75	-	-
Battery	-	-	-	-	-	-	-

[449] Solar includes green future initiatives, community solar PPA, and PPA. Hydropower includes hydro efficiency upgrades and hydro RPS.

	2023	2024	2025	2030	2035	2040	2043
Storage	4	4	4	4	-	-	-
Total	**1,289**	**1,376**	**1,382**	**568**	**528**	**93**	**93**

E.2.6 Qualifying facility contracts

PGE has contracted to purchase the output of numerous QF projects. The 2023 IRP includes QF contracts executed as of June 02, 2022, up to 601MW during 2023 to 2043. **Table 109** and **Table 110** summarize the QF contracts by technology and year-end capacity.

Table 109. Qualifying facility by technology, MWa

	2023	2024	2025	2030	2035	2040	2043
Solar	108	129	132	132	96	1	1
BioGas	9	9	9	4	4	-	-
Biomass	5	5	5	5	-	-	-
Hydropower	4	4	4	4	2	-	-
Wind	3	3	3	3	-	-	-
Total	**129**	**151**	**154**	**148**	**102**	**1**	**1**

Table 110. Qualifying facility by technology, MW (year-end)

	2023	2024	2025	2030	2035	2040	2043
Solar	471	553	564	564	455	6	4
BioGas	10	10	10	5	5	-	-
Biomass	10	10	10	10	-	-	-
Hydropower	7	7	7	7	3	-	-
Wind	9	9	9	9	-	-	-
Total	**508**	**590**	**601**	**594**	**463**	**6**	**4**

E.3 Customer side

E.3.1 Energy efficiency

PGE has a long history of working with the Energy Trust of Oregon (Energy Trust) to identify and acquire cost-effective energy efficiency measures to help customers reduce their energy use. Oregon is a national leader in capturing energy efficiency through the combined efforts of the Energy Trust, customers, and utilities. **Section 8.2, Additional distributed energy resources, Chapter 8, Resource options**, discusses the long-term energy efficiency savings forecast for the 2023 IRP, and **Ext. Study-II, EE methodology** contains a report from Energy Trust describing their forecasting methodology.

E.3.2 Demand response

In June 2021, the Commission accepted PGE's Flexible Load Plan, which laid out a holistic plan to accelerate flexible load development.[450] In 2022, PGE enrolled 93 MW of available summer demand response (DR) capacity and 63 MW of available winter DR capacity. **Section 6.2.2, Demand response, Chapter 6, Resource needs** describes PGE's current demand response programs.

E.3.3 Dispatchable standby generation

PGE's dispatchable standby generation (DSG) program provides PGE with additional generation capacity by contracting with large nonresidential customers for the right to operate their generation resources for the purpose of providing grid services and averting situations that could lead to power quality problems for the power supply in the local region.[451]

Effective June 1, 2022, Schedule 200 was updated to include battery energy storage resources in addition to the existing generator tariff. The new tariff update enrolls large battery resources for ancillary services in addition to demand response and peak shaving activities. This update is anticipated to add up to 8 MW of enrolled storage in 2023 to support PGE's decarbonization and flexible load objectives.

[450] Order No. 21-158.
[451] Schedule 200, Dispatchable Standby Generation, Issued April 7, 2022, Microsoft Word - 200 22-05 Eff June 1.2022 (ctfassets.net)

As of September 2022, PGE had agreements for approximately 127.8 MW of Dispatchable Standby Generation (DSG) capacity as a low-cost resource (approximately $42/kW-yr., including capital and fixed O&M, 2023$).

E.3.4 Distributed generation

Distributed generation is electrical generation and storage performed by a variety of small, grid-connected or distribution system-connected devices. It can be sited at a customer premise located behind the meter (e.g., rooftop solar or municipal biogas projects) or can be small power producing projects such as qualifying facilities. Distributed generation and storage provide a supply of energy from many sources and may lower environmental impacts and improve the security of supply.

As of February 2023, the In-Service Net Metering program produces approximately 183 MW, in which 53 percent of that capacity comes from rooftop solar facilities. Estimated nameplate capacity of 124 MW come from 47 in-service qualified facilities (QFs). There are 36 MW of nameplate capacity that are not yet producing power but have applied for integration with the grid. Owned resources are included in **Section E.1, Existing resources**, and contracted resources are included in **Section E.2, Contracted resources**.

The other distributed generators include low-impact hydropower, small-scale wind, fuel cells, biogas generators, and combined heat and power (CHP). Most of these are contracted for by PGE and are included in **Section E.2, Contracted resources**.

Appendix F. Load resource balance

This appendix includes information on projected capacity and energy needs in the 2023 IRP before new IRP resources are added (contracted resources that have not been constructed yet, like Clearwater, are included in some cases). In some instances, like the capacity load-resource balance, the data are not used in the IRP and are included for informational purposes only.

F.1 Projected capacity load – resource balance

For the 2023 IRP PGE uses a stochastic model (Sequoia) that targets a seasonal adequacy metric of 2.4 hour of lost load per season to determine resource adequacy need. PGE does not create a traditional load/resource balance capacity assessment as part of the IRP. **Table 111** and **Table 112** present an illustrative view of PGE's capacity need during the summer and winter. The resource values are approximations and should be interpreted directionally rather than as absolutes. This table and methodology are not used for power planning by PGE; for power planning the capacity need value directly from Sequoia is used.

Load and resource approximations are as follows:

- Thermal resources are derated 5 percent for outages and other contingencies (actual outage rates in Sequoia differ by unit and are calculated stochastically). Some thermal resources have different levels of peak generation between winter/summer due to temperatures.
- Wind, solar, DERs, other resources (representing biomass/biogas), and storage resources are estimated used proxy resource unturned ELCC values for year 2026 at the 100 MW increment (for wind and solar the average ELCC of the three proxy sites is used). Actual wind and solar performance will vary since the untuned ELCC values are based on new technology rather than existing resources. Hybrid resources are approximated in the disaggregate. Committed resources, like Clearwater Wind, and 2021 RFP proxy resources, are included in the table.
- Hydro values are approximate, include hydro contracts, and are a combination of nameplate/net values with a derate based on average hydro performance during an outage in the Sequoia model. Actual hydro performance will vary based on water conditions, the hours leading up to the peak event, and other factors.
- Contracts and market are at 100 percent nameplate value.
- Loads represent Reference Case 1-in-2 seasonal peak loads and include the impact of energy efficiency and vehicle and building electrification.

As noted earlier, these tables are an illustrative representation of capacity needs on the PGE system. The capacity need value used in IRP modeling is calculated using the Sequoia model which stochastically simulates millions of possible resource and load combinations and takes portfolio impacts, hourly generation and load profiles, temperature, water year, and other factors into consideration. For more information on Sequoia please see **Section H.3 of Appendix H, 2023 IRP modeling details**.

Lastly, the planning margin shown is back-calculated based on 1-in-2 peak load estimates, the resource estimates as defined above, and the capacity need out of Sequoia. Planning margins vary based on resource assumptions. For example, if we assume lower hydro generation (or lower generation from any resource) that would lead to a lower planning margin. The planning margins from these tables are not directly comparable to planning margins used in other reports and are not used in the 2023 IRP.

F.2 Estimated annual capacity need, MW[452]

Table 111. Estimated load resource balance, summer peak capacity need

All values apprx. MW	2024	2025	2026	2027	2028	2029	2030	2035	2040	2043
Natural gas	1,698	1,698	1,698	1,698	1,698	1,698	1,698	1,698	-	-
Coal	281	281	281	281	281	281	-	-	-	-
Hydro	970	970	623	623	623	579	579	577	541	406
Solar and wind	658	773	775	777	780	775	777	744	532	531
DERs and DSG	180	197	214	226	240	251	268	337	257	281
Storage	35	311	311	311	311	311	311	297	297	297
Contracts and other	15	15	15	15	11	11	11	4	-	-
HLH Market	-	-	-	-	-	-	-	-	-	-
Total resource	3,838	4,246	3,918	3,933	3,944	3,906	3,645	3,656	1,626	1,515

[452] This table is provided in compliance with IRP guideline 4c "For electric utilities, a determination of the levels of peaking capacity and energy capability expected for each year of the plan, given existing resources; identification of capacity and energy needed to bridge the gap between expected loads and resources; modeling of all existing transmission rights, as well as future transmission additions associated with the resource portfolios tested."

All values apprx. MW	2024	2025	2026	2027	2028	2029	2030	2035	2040	2043
Median peak load	3,776	3,828	3,888	3,948	4,001	4,061	4,124	4,535	5,027	5,316
Sequoia capacity need	344	51	506	568	624	791	1,136	1,647	4,173	4,488
Implied margin	11%	12%	14%	14%	14%	16%	16%	17%	15%	13%

Table 112. Estimated load resource balance, winter peak capacity need

All values apprx. MW	2024	2025	2026	2027	2028	2029	2030	2035	2040	2043
Natural gas	1,785	1,785	1,785	1,785	1,785	1,785	1,785	1,785	-	-
Coal	281	281	281	281	281	281	-	-	-	-
Hydro	1,063	1,063	683	683	683	634	634	633	593	445
Solar and wind	664	693	693	694	695	685	686	674	595	595
DERs and DSG	134	141	149	155	160	165	171	198	99	104
Storage	22	198	198	198	198	198	198	189	189	189
Contracts and other	117	17	17	17	12	12	12	4	-	-
HLH Market	200	200	150	150	150	150	150	150	150	150
Total resource	4,267	4,379	3,957	3,963	3,964	3,911	3,636	3,633	1,626	1,484
Median peak load	3,580	3,635	3,699	3,766	3,831	3,885	3,954	4,389	4,904	5,197
Sequoia capacity need	55	-	430	502	614	683	1,004	1,461	3,912	3,885
Implied margin	21%	20%	19%	19%	19%	18%	17%	16%	13%	3%

F.3 Seasonal capacity need by Need Future, MW[453]

Table 113. Summer capacity need by Need Future (MW)

	2024	2025	2026	2027	2028	2029	2030	2035	2040	2043
Low	224	0	364	402	435	579	894	1197	3526	3869
Reference	344	51	506	568	624	791	1136	1647	4173	4488
High	395	136	617	704	786	982	1357	2065	4753	4670

Table 114. Winter capacity need by future (MW)

	2024	2025	2026	2027	2028	2029	2030	2035	2040	2043
Low	0	0	213	285	359	404	708	952	3173	3524
Reference	55	0	430	502	614	683	1004	1461	3912	3885
High	106	0	628	745	864	949	1302	1986	4618	4217

F.4 Projected annual average energy load-resource balance, MWa

Table 115 presents PGE's energy load-resource balance (LRB) given no incremental resource actions (except for energy efficiency) in a linear carbon reduction glidepath. As with the LRB presented in **Section 6.5, Energy need**, the availability of energy from GHG-emitting sources declines through time as a result of GHG constraints. The 'Other PPA + market purchases' category represents market purchases and PPAs with associated GHG emissions. Energy efficiency (EE) actions are included as a resource and reflect cumulative savings beginning in 2023 with adjustments for intra-year deployment and line losses. Forecasted load is the annual average load before incremental EE actions.

[453] This table is provided in compliance with IRP guideline 4c "For electric utilities, a determination of the levels of peaking capacity and energy capability expected for each year of the plan, given existing resources; identification of capacity and energy needed to bridge the gap between expected loads and resources; modeling of all existing transmission rights, as well as future transmission additions associated with the resource portfolios tested."

Table 115. Projected annual average energy load-resource balance, MWa

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Gas	699	697	648	562	498	428	333	287	258	223	194	163	136
Coal	147	134	130	115	91	66	50	0	0	0	0	0	0
Hydropower	180	180	180	180	180	180	180	180	180	180	180	180	180
Hydropower Contracts	338	347	337	244	241	228	183	183	183	181	177	177	177
Wind	348	487	487	487	487	486	479	479	479	479	479	479	479
Solar	103	128	242	241	241	240	239	248	248	247	246	246	245
Other PPA + Market Purchases	659	535	524	413	331	254	197	173	157	145	128	114	95
Energy Efficiency	31	61	91	121	151	181	214	247	282	316	348	379	408
Qualified Facilities (online)	81	81	81	81	80	75	75	75	74	59	51	46	29
Qualified Facilities (not online)	49	70	73	73	73	73	73	73	73	73	73	73	73
Total Resources	2,636	2,722	2,792	2,517	2,373	2,212	2,024	1,947	1,933	1,903	1,877	1,857	1,823
Load	2,352	2,428	2,498	2,576	2,651	2,716	2,781	2,852	2,932	3,012	3,095	3,183	3,268
Energy Surplus/ (Deficit)	-284	-293	-295	59	278	504	757	905	999	1,109	1,218	1,326	1,446

Appendix G. Market capacity study

PGE's resource adequacy model, Sequoia, simulates PGE loads, owned resources, and long-term contracts. The PGE system is modeled as a power island, requiring sufficient owned or contracted resources to meet load every hour. In reality, the PGE system is part of the Western Interconnection. By being part of the Interconnection, PGE can buy and sell power with other entities, optimizing power costs, reducing risk, and potentially using purchased power for resource adequacy.

PGE may be able to buy power on short-term markets from others for resource adequacy needs. However, there may be seasons and hours when buying power is challenging due to competition from other utilities, transmission limitations, and other factors. The Western Interconnection is transforming into a cleaner power system. More wind and solar resources are arriving on the system and thermal dispatchable resources are being retired. New loads are forecasted to arrive from transportation and end use electrification along with high-tech industry (like data centers). As a result, predicting how much power PGE can rely on from the market for resource adequacy in future years is challenging.[454]

To approximate future short-term power market availability during heavy-load hours, the 2023 IRP uses a load-resource balance study for the Northwest region.[455] This study compares existing and committed resources in the Northwest against projected loads and exports to estimate if the Northwest is surplus or deficit in the winter and summer.[456]

G.1 Key input sources and changes

The key study inputs come from the following sources:

- The Power Council's 2021 Power Plan and GENESYS Classic model (as used in the Power Plan) provide the loads, resources, regional power market assumptions (imports from outside the Northwest), and power plant availability assumptions used in the workbook.
- The BPA White Book provides import/export assumptions for the Northwest, the largest being the Columbia River Treaty export.

Compared to the market capacity study in the 2019 IRP Update there have been impactful changes to the assumptions, most notably the usage of climate change model data for load

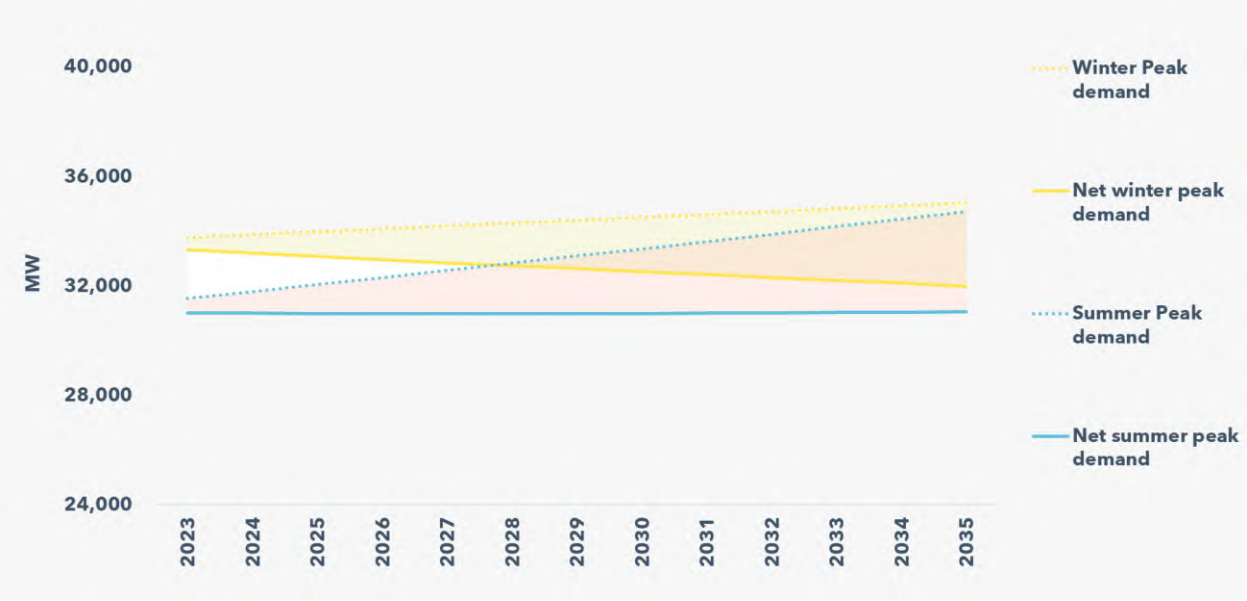
[454] More discussion on the changing west is in **Chapter 4, Futures and uncertainties**.
[455] Heavy-load hours are Monday through Saturday, hours ending 7 through hour ending 22, excluding NERC holidays. Light load hours are all other hours. The Northwest region is roughly ID, OR, WA, and Western MT.
[456] Winter is mid-November through mid-March, and summer is mid-June through September. The workbook used for the analysis originates from the 2019 IRP analysis performed by E3, a consultancy.

and hydropower inputs.[457] These changes lead to higher loads and lower hydropower generation in the summer, and lower loads and higher hydropower generation in the winter. This study indicates that surplus power is available in the winter but not in the summer. This conclusion differs from the 2019 IRP Update analysis that saw zero market power available in the winter Reference Case and limited power available in the summer. The change in findings is largely due to moving to climate change model data.[458]

G.2 Load and demand side resource assumptions

The load assumptions in the study are based on the 2025 load input file to the GENESYS Classic model and uses the average one-hour peak load for winter and summer. Using this starting point, the load scales up and down based on the 2021 Power Plan growth trends. Power Plan data are used to estimate the amount of energy efficiency and demand response in the analysis as well. **Figure 124** shows the load projections (dashed lines), demand side measure impacts (in shading), and net peak loads for this study (solid lines). The winter net load forecast experiences load decay, whereas the summer net load forecast is mostly flat.

Figure 124. Peak load forecasts



[457] Load and hydro assumptions are from the Power Council, which switched to climate change data for their 2021 Power Plan.
[458] The Power Council has additional discussion on how changing from historical data to climate change data impacted adequacy in their GENESYS classic modeling. Part of that discussion can be found here:https://nwcouncil.app.box.com/s/t40vm814w7qu86uzc00a5jckyofq72zh

G.3 Supply-side resource assumptions

The resources in this study come from the Power Council's resource database.[459] Only existing and firmly committed supply-side resources are in the analysis.[460] Resources are derated from nameplate values to their effective capacity values based on Power Council estimates.[461] One of the most significant adjustments occurs with hydropower, which is derated to its minimum 10-hr sustained peaking level in the climate change record.[462] The supply-side resource capacity contributions for summer and winter 2026 by fuel type are in **Table 116**.

Table 116. 2023 resource capacity contribution (MW)

	Summer	Winter
Hydropower (10-hr)	15,013	21,431
Natural gas	8,782	8,939
Coal	4,429	4,487
Nuclear	1,017	1,035
Wind	2,114	917
Solar	736	544
Other	694	694

One driver of Northwest resource adequacy challenges is coal unit retirements. **Table 117** explores how Northwest coal units are assumed to retire in the next decade. A change to the schedule would impact the study results. There are some changes in assumptions from the 2021 Power Plan in this study as shown in **Table 117**.

Table 117. Major coal power plants in the Northwest

Unit	Study Assumption	2021 Power Plan Assumption
Hardin	Retired	Retired
Colstrip 1	Retired	Retired

[459] Additional information available at: https://www.nwcouncil.org/energy/energy-topics/power-supply/
[460] Resources assumptions for this analysis were mostly frozen in spring 2022.
[461] Additional information available at: https://nwcouncil.app.box.com/s/k12r8hry1ofogeqxgjw8spgnv2n55lvm
[462] Ten-hour sustained peak derived from data in the GENESYS model. Compared to the 2019 IRP Update values, there is an extra ~3,600 MW of hydropower in the winter, and ~400 MW less in the summer.

Unit	Study Assumption	2021 Power Plan Assumption
Colstrip 2	Retired	Retired
Boardman	Retired	Retired
Centralia 1	Retired	Retired
N Valmy 1	Offline for NW in 2021	Offline for NW in 2021
N Valmy 2	Retiring end of 2025	Retiring end of 2025
Centralia 2	Retiring end of 2025	Retiring end of 2025
Colstrip 3	Offline for NW in 2030	Retiring end of 2035
Colstrip 4	Offline for NW in 2030	Retiring end of 2035
Bridger 1	Converting to gas	Retiring end of 2023
Bridger 2	Converting to gas	Retiring end of 2028
Bridger 3	Online	Online
Bridger 4	Online	Online

G.4 Import and export assumptions

Beyond loads and resources, the workbook takes key imports and exports into account. Export assumptions are from the BPA White Book. The Columbia River Treaty Canadian entitlement is the primary export in the workbook. Import assumptions come from the Power Council, with resource availability from outside the region (as included in the GENESYS Classic Model) being the primary import (winter only).[463] All Northwest located IPP resources are assumed to be fully available in the winter and are limited to 2,500 MW in the summer. **Table 118** shows import, export, and IPP assumptions in 2023 for winter and summer.

[463] This is often referred to as imports from the Southwest in Power Council analysis. Additional imports could potentially be available depending on the load/resource balance in other parts of the West and transmission expansion to other regions (for example, transmission expansion into Canada could potentially bring more power to the Northwest during certain hours).

Table 118. 2023 imports/exports/NW IPPs (MW)

	Summer	Winter
Imports	16	2,565
Exports	1,564	1,143
NW IPPs	2,500	2,716

G.5 Planning reserve margin assumptions

Planning reserve margins account for operating reserves, load deviations from extreme weather, forced outages (or higher than expected levels of forced outages), and other factors. This analysis uses three planning margins, 10 percent, 12.5 percent, and 15 percent. The three margins set the high (10 percent), reference (12.5 percent), and low (15 percent) market power assumption cases.

G.6 Results

Figure 125 and **Figure 126** show the load resource balance for the Reference Case summer and winter estimates. Note the step down in coal resources following 2025 and 2029.

Figure 125. Northwest summer peak load/resource balance

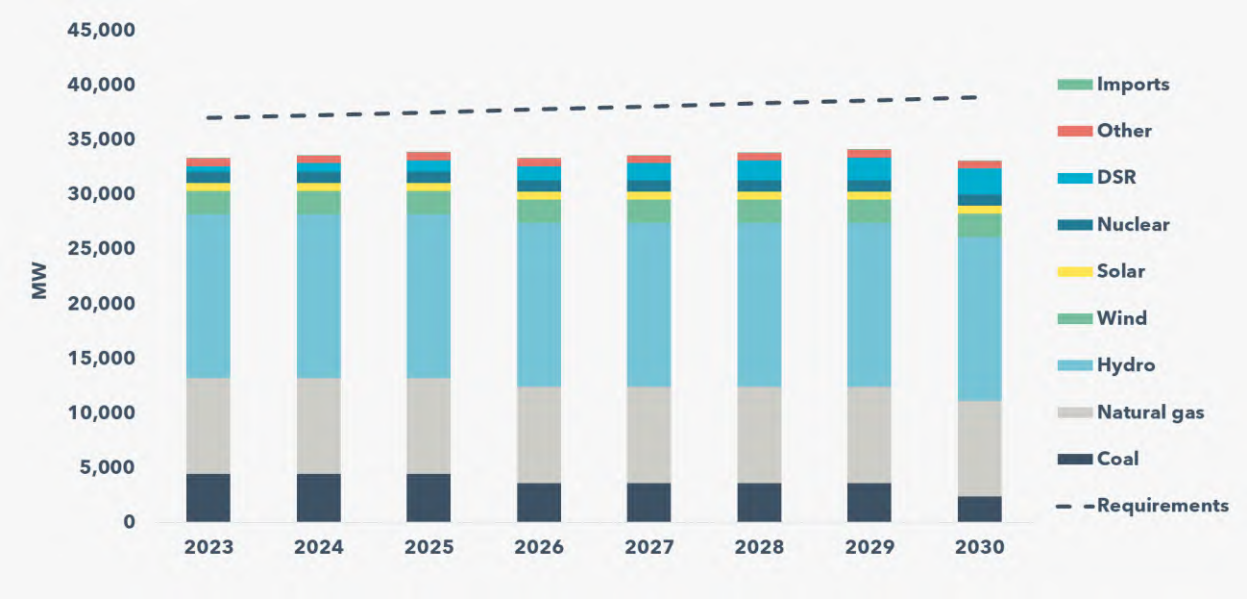
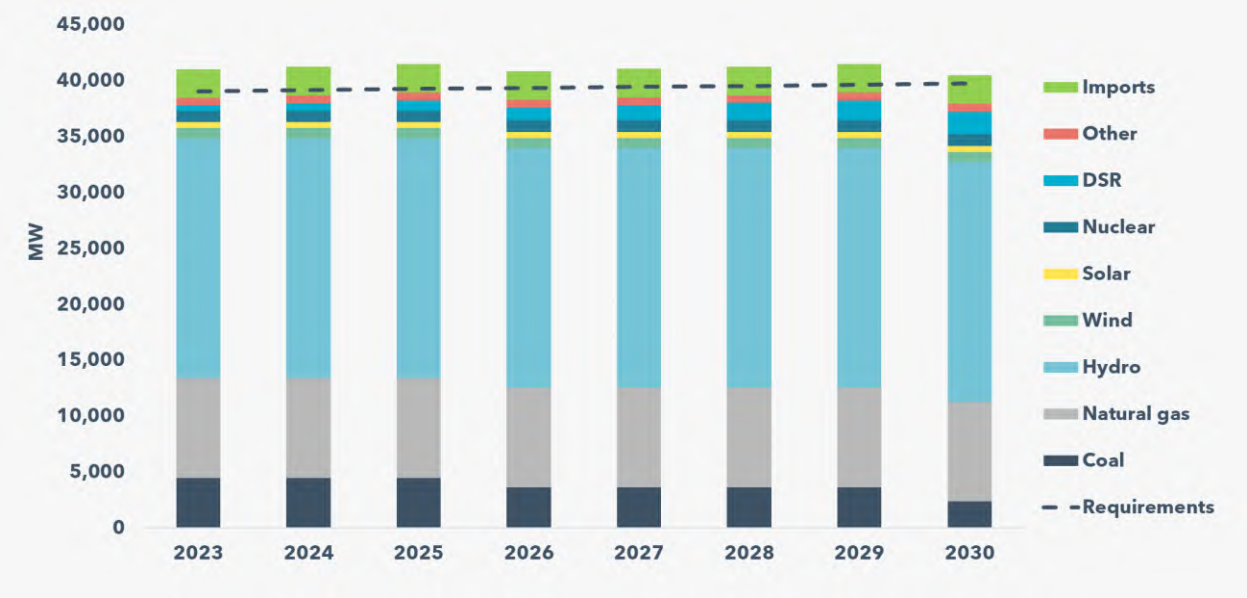


Figure 126. Northwest winter peak load/resource balance



In years with a power surplus PGE is assigned a share of the extra MWs. The share is based on the ratio of PGE's peak load to the Northwest region's peak load – roughly 10 percent. For example, if there is a 1,000 MW surplus, PGE's share is around 100 MW. For simplicity, and due to uncertainty regarding future loads and resources, the surplus values from 2023 through 2025 are averaged together, rounded to the nearest 50 MW, and used as the power market assumption in years 2023 through 2025. The average of the 2026 through 2035 surplus values are used as the power market assumption in year 2026 forward. The resulting heavy-load-hour market assumptions for the Reference Case are in **Table 119** and **Table 120**.

Table 119. Reference case 2023 IRP HLH market capacity

	2023	2024	2025	2026	2027	2028	2029	2030
Ref. Summer (HLH)	0	0	0	0	0	0	0	0
Ref. Winter (HLH)	200	200	200	150	150	150	150	150

The 2023 IRP has three market forecasts, low, reference, and high. They differ by planning reserve margin. The low case (lowest market availability) uses a 15 percent planning margin, the reference-case 12.5 percent, and the high case 10 percent. In all three cases, summer market power is zero. Winter market power availability varies by planning margin and year.

Table 120. High, reference, and low HLH market estimates

2023 IRP	2025 and earlier	2026 forward
High Summer (HLH)	0	0
High Winter (HLH)	300	250
Ref. Summer (HLH)	0	0
Ref. Winter (HLH)	200	150
Low Summer (HLH)	0	0
Low Winter (HLH)	150	50

G.7 Light load hour and shoulder season market assumptions

Unlike the heavy load hour (HLH) assumptions for winter and summer, the light load hour (LLH) and shoulder season assumptions are not based on a supply and demand balance study. For the spring and fall, 200 MW of HLH market power are assumed to be available in all years in the Reference Case. During light load hours in all months and years, a range of market power availability of 999 MW to 400 MW is used. The value declines as load increases (for example, during the highest load days there are 400 MW of LLH market available, during the lowest load days there are 999 MW available).

G.8 Limitations

The Power Council's Power Plans are produced every five years. Resultingly, the data and assumptions that underpin this market power assessment can fall behind the pace of public policy. Additionally, this assessment, a peak hour load/resource balance snapshot, is simplistic and does not take net load, flexibility challenges, transmission, and other factors into consideration. Going forward, PGE will seek more sources of data and more sophisticated approaches for assessing regional power market availability in IRPs and other planning work.

There may be a future opportunity to link IRP power market availability assumptions to work done by the Western Power Pool via the Western Resource Adequacy Program (WRAP). The WRAP was not sufficiently advanced to be used in this IRP cycle. PGE will consider using data from the WRAP to inform the market capacity study in future planning cycles.

Lastly, the estimates from this study are for long-range planning and are not at the detail needed for shorter-term operation applications.

Appendix H. 2023 IRP modeling details

The 2023 IRP relies on multiple models to create forecasts for power prices, emissions, capacity need, energy need, and more. This appendix provides additional detail on those models.

H.1 Aurora

Aurora is electric market forecasting and analysis software produced and maintained by Energy Exemplar. PGE uses Aurora to simulate wholesale electricity prices and resource dispatch. Within the use of Aurora, we use a separate model for each task: a regional WECC model, described in **Section H.1.1, Aurora – WECC model**, and a PGE-zone-only portfolio model (PZM), described in **Section H.1.2, Aurora PGE Zone Model**.

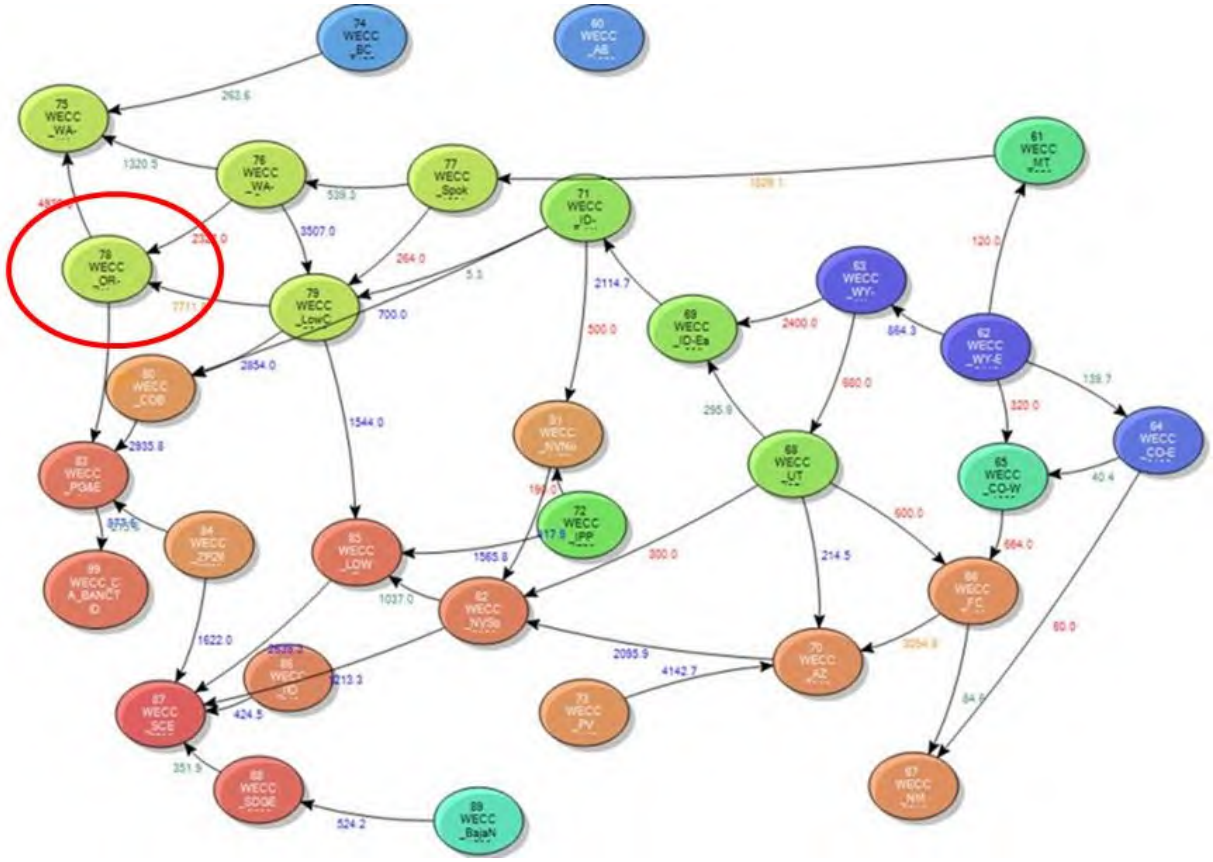
H.1.1 Aurora – WECC model

The Western Electricity Coordinating Council (WECC) model is a regional model provided by the global research consultancy, Wood Mackenzie. PGE input all the assumptions of the 2020H2 WECC model into Aurora as the base case environment for simulation and forecasting. Wood Mackenzie releases long-term forecasts twice a year. PGE updated the wholesale natural gas price forecast with 2022H1 gas price (which was published in June of 2022). In addition to commodity prices, Wood Mackenzie models the following information:

- Load and resources by geographical area. Resources are existing and new additions to meet the forecasted load through 2043.
- Transmission: capacity, constraints, wheeling costs, and carbon hurdle rates. Both existing and transmission lines planned and under construction are modeled.
- Macroeconomic data: environmental costs, inflation, etc.
- Calibration of resource behavior and optimization parameters.

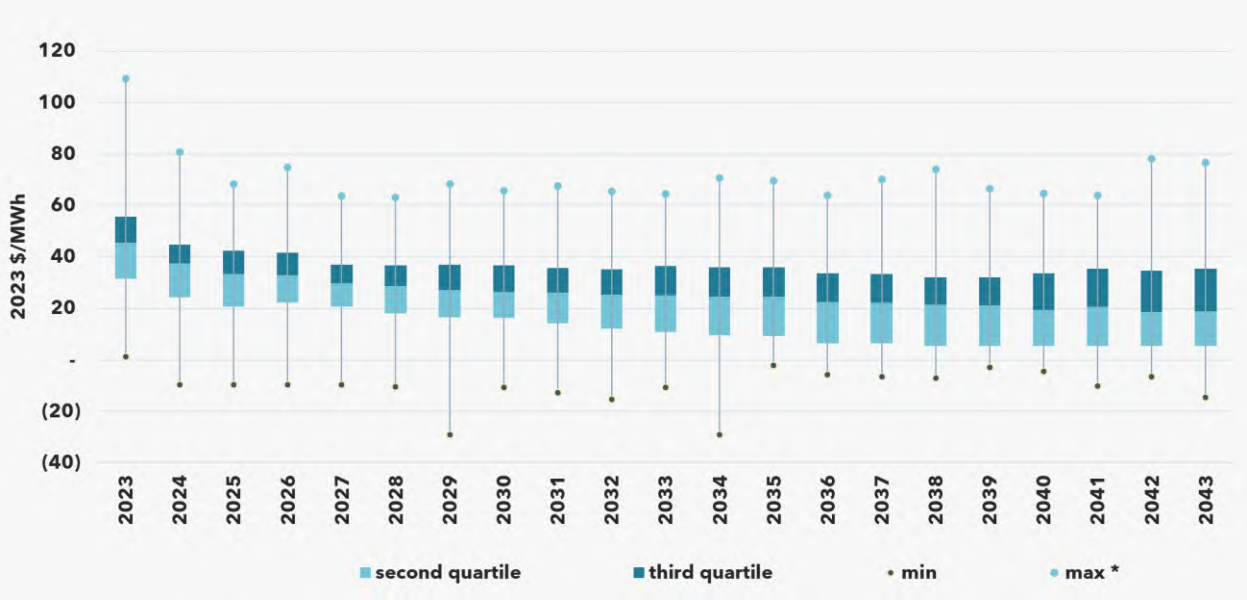
PGE uses the WECC model to forecast hourly electricity prices for the Pacific Northwest. This analysis is a regional simulation where PGE applies Wood Mackenzie's WECC assumptions, such as the growth and reduction of resource technology from 2023-2043, carbon policy, and resource capacity to maintain unbiased input of parameters and resource behavior. **Figure 127** shows the topology modeled in our WECC model: the colored bubbles represent geographical entities for which Aurora forecasts prices, and the lines represent transmission links for imports and exports. The model's objective is to minimize prices for WECC, given constraints on generation and import-exports across zones.

Figure 127. Illustrative snapshot of modeled WECC topology



For this analysis, PGE used Aurora version 14.0.1084 with the algorithmic performance optimizer, GUROBI. We simulated hourly prices from 2023 to 2043 for all areas and multiple futures, where we changed input assumptions. The Pacific Northwest is represented by 6 different areas of which Oregon West (highlighted in red in **Figure 127**), was chosen as best representative of the Pacific Northwest prices overall for PGE. Simulated Oregon West hourly prices for each future are then input in PZM and used to dispatch PGE resources. The Reference Case hourly electricity prices are summarized in **Figure 128**.

Figure 128. Reference case hourly electricity price range by year



To account for market uncertainty and volatility, PGE models three gas price futures (reference, high, and low) to capture a range of possible gas prices. The reference forecast is constructed using these components:

- 2023-2026 prices reflect PGE's 2022 Q2 forward gas trading price curve
- 2027 prices are a linear interpolation of 2026 prices and 2028 prices
- 2028-2043 prices are WM 2022 base long-term price forecast

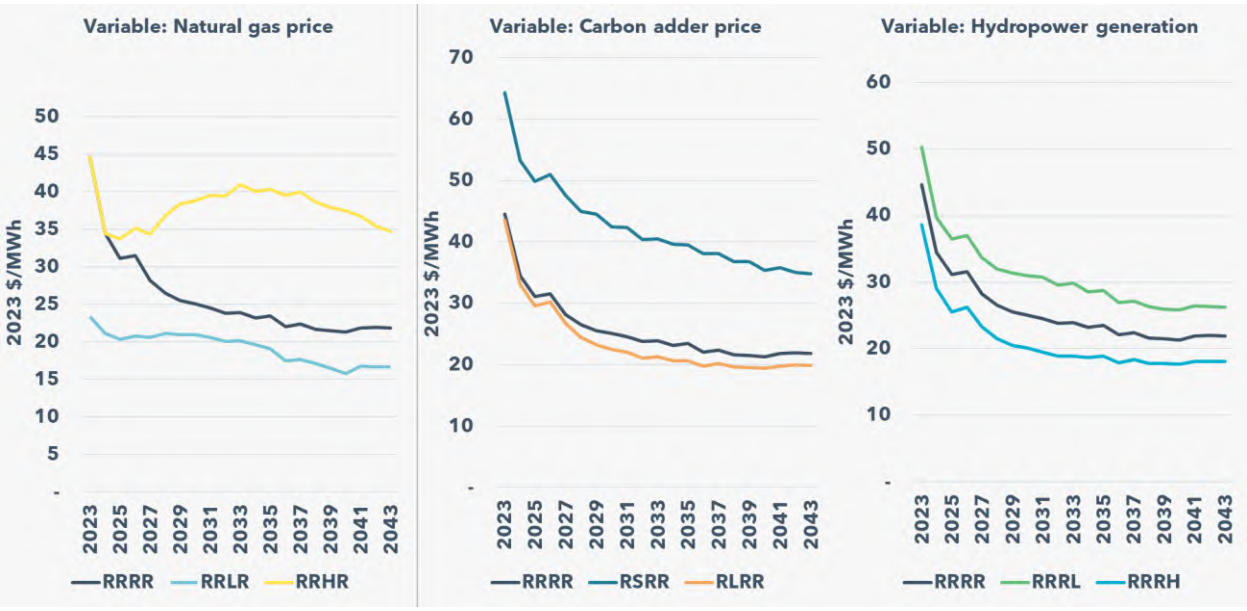
To model low gas price futures, PGE set a natural gas price floor of $2.30 per MMBtu for Henry Hub and applied a proportionate differential basis to other natural gas hubs. This price floor is based on Henry Hub's lowest gas price since 2016, which is approximately $2.30 per MMBtu. Putting a floor of $2.3 per MMBtu approximates a scenario where gas supply has no bottlenecks, and increased exports do not offset the shrinking domestic demand for electricity generation.

The High Gas Price Future applies the highest gas price scenario of the 2021 Annual Energy Outlook (AEO) forecast beginning in 2022. Among the scenarios published for the 2021 AEO, the Low Oil and Gas Supply case results in the highest long-term projection of gas prices. This is an approximation based on the U.S. Energy Information Agency (EIA) assessment of reduced ultimate recovery per well, limited stock of undiscovered resources, and a slow rate of cost-saving technological advancement.

PGE simulated 39 futures by varying four major risk drivers: natural gas prices, carbon price adders, PNW hydropower generation levels, and system commitment/scarcity. The construction of these price futures was discussed in **Chapter 4, Futures and uncertainties.**

The 2023 IRP Reference Case is modeled as a default Aurora setup, reference California Energy Commission (CEC)[464] carbon prices added to carbon-emitting resources in California and Washington and tax carbon prices to carbon-emitting resources in British Columbia and Alberta, reference natural gas price, and reference hydropower generation condition. **Figure 129** shows the impact on the reference prices of the risk drivers that capture commodity and carbon risk: natural gas prices, carbon adders, and hydropower generation. These risk drivers lead to a sustained different price level than the Reference Case and capture a wide range of possible price outcomes.

Figure 129. Wholesale electricity market price comparison between reference and individual variables



In this IRP, PGE added a few futures that proxy a system with increasing demand and supply balancing difficulty. This is because the Western Electricity Coordinating Council (WECC) electricity market transition to largely non-dispatchable resources combined with the still largely unquantifiable impact of climate change on load, wind, and hydro patterns. For these reasons, modeling cannot rely on history or widely adopted methodology. Consequently, PGE employs two Aurora features to incorporate forecast error into an otherwise perfectly balanced system and consider scarcity premiums on prices.

In Aurora, PGE applied the Dispatch Uncertainty table to the Pacific Northwest to mimic operational errors of wind generation forecast and dispatch commitment misalignment. The forecast errors are plus or minus 15 percent of wind nameplate capacity applied randomly to an hour each month. Such a percentage is based on the Wind Integration Study for hour-

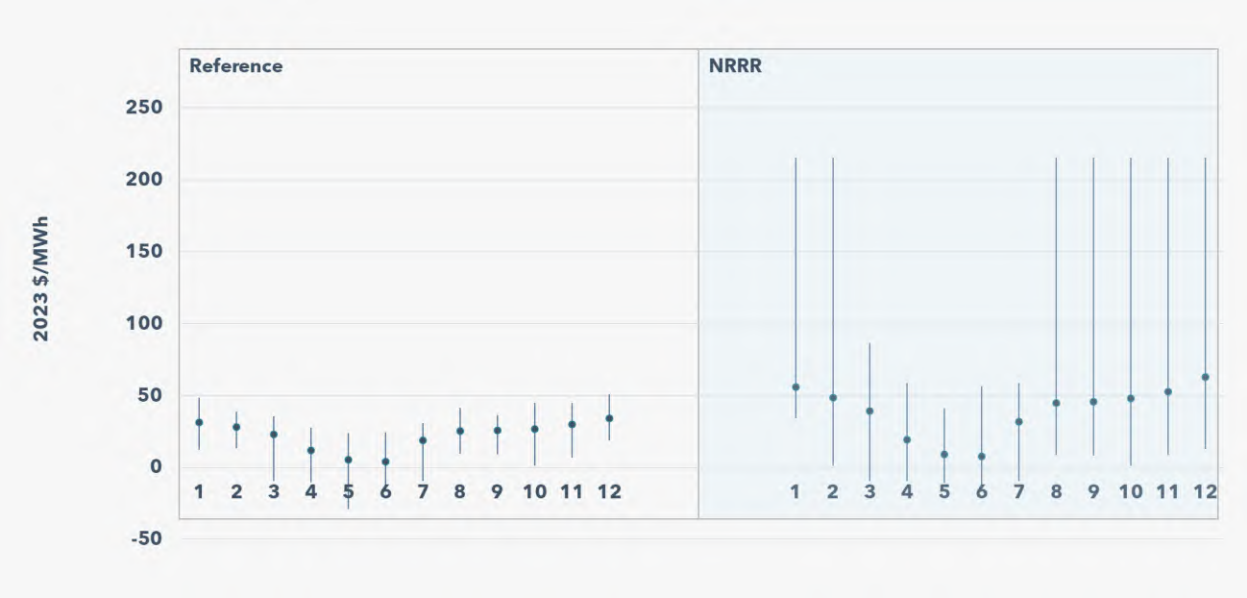
[464] PGE references the California Energy Commission (CEC)'s Integrated Energy Policy Report (IEPR) 2019 carbon price outlook for California. Available at: TN232922_20200506T151733_Adopted 2019 Integrated Energy Policy Report.pdf

ahead wind generation error. This error size is adequate to capture net load shocks. We simulated two futures with this characteristic: one in which all other risk inputs are set as Reference Cases and another future that has high gas prices and low hydro conditions. All other zones in WECC are kept with perfect foresight or no forecast error.

The default Wood Mackenzie database models a cycle of four different wind years, 2016-2019. The same error pattern is applied to the four wind years. The impact on annual average simulated wholesale electricity prices is generally moderate. Still, the volatility triggered by such an error is very different and much higher than the Reference Case, see **Figure 130**. The bar represents the range between minimum and maximum hourly prices for the month of 2031. The dot is the average monthly price.

For many hours, the model could not find resources to meet demand as the spare capacity was not committed and triggered the price cap of $1000 per MWh. The instances of $1000+ prices were so frequent that we reduced the price cap to $250 per MWh in these futures. Capping the price at $250 per MWh reflected the price experienced during the 2000 energy crisis, providing a likely scenario.

Figure 130. Intra-month hourly price volatility with dispatch uncertainty in 2030



Scarcity premium is a significant component of procurement economics. When resource capacity is scarce, the marginal cost of dispatch becomes higher since more expensive resources get dispatched to meet the load. These dispatched resources' associated maintenance and operational costs add to the scarcity premium. Typically, they are modeled in long-term models like Aurora because of their strong dependence on short-term zone-specific conditions. However, PGE agreed with stakeholders in the public process that occasional scarcity might be a characteristic of WECC given the uncertainty both on resource

generation and load going forward. PGE proxied such premiums with the startup cost of thermal plants. In Aurora, PGE activated an Uplift Logic in which the startup cost of thermal plants is added to the dispatch cost. This cost is spread across the online hours of the thermal plants and consequently reflected in the electricity prices. We activated this logic for all hubs in the PNW and on-peak hours. This adder does not affect the annual average level of wholesale prices much. Volatility is shown in **Figure 131** for the year 2030, but price caps in this future are not triggered. The bar represents the range between minimum and maximum hourly prices for the month of 2030. The dot is the average monthly price.

Figure 131. Intra-month hourly price volatility with scarcity premiums: year 2030

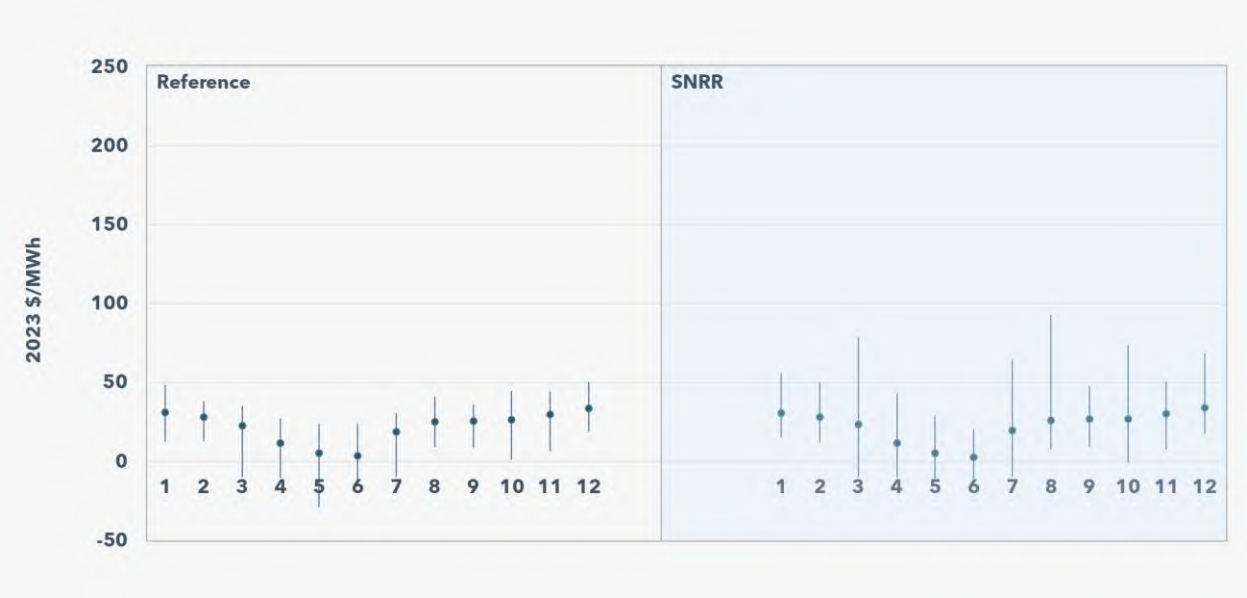


Table 121, **Table 122**, and **Table 123** show the annual average wholesale electricity prices simulated for all 39 futures.

Table 121. Average annual wholesale electricity prices for PNW by future (2023 $/MWh)

Year	NRHH	NRHL	NRHR	NRRH	NRRL	NRRR	RLHH	RLHL	RLHR	RLLH	RLLL	RLLR	RLRH	RLRL	RLRR	RRHH
2023	39.2	51.3	45.3	39.1	51.1	45.3	37.7	49.0	43.6	18.5	25.3	22.3	37.7	49.0	43.5	38.7
2024	28.8	39.9	34.5	28.7	39.8	34.4	28.0	37.8	33.1	16.4	23.4	20.0	28.1	37.6	33.1	29.0
2025	27.5	39.1	33.2	25.3	36.6	30.9	26.7	36.8	31.9	15.4	22.4	18.9	24.7	34.1	29.6	27.7
2026	31.3	43.1	37.2	28.0	39.2	33.3	28.6	38.7	33.8	16.2	22.6	19.2	25.5	34.8	30.2	29.6
2027	29.6	41.8	35.6	24.2	35.0	29.5	27.6	37.5	32.7	15.7	22.3	18.9	22.3	30.8	26.7	28.6

Year	NRHH	NRHL	NRHR	NRRH	NRRL	NRRR	RLHH	RLHL	RLHR	RLLH	RLLL	RLLR	RLRH	RLRL	RLRR	RRHH
2028	31.1	44.5	37.5	22.0	33.2	27.7	29.5	39.5	34.7	15.8	22.6	19.2	20.5	28.4	24.5	30.8
2029	31.7	45.6	38.6	20.5	32.1	26.1	30.5	41.0	36.1	15.3	22.3	18.8	19.4	27.1	23.2	31.7
2030	35.3	50.5	42.3	22.5	35.3	28.3	30.8	41.1	35.8	15.1	21.8	18.4	18.8	26.1	22.4	32.5
2031	34.9	50.5	42.4	21.1	35.3	26.8	31.4	42.2	36.8	14.8	21.7	18.2	18.4	26.0	22.0	33.0
2032	33.9	48.9	41.2	20.0	32.3	25.3	31.5	41.8	36.3	14.1	20.7	17.3	17.6	24.9	21.1	33.3
2033	34.2	49.0	41.1	19.3	30.6	24.7	32.6	43.3	37.8	14.3	20.9	17.3	17.7	25.0	21.3	34.4
2034	37.4	51.6	43.8	21.0	32.7	26.2	32.3	42.2	37.1	14.1	20.2	17.0	17.3	24.1	20.6	34.3
2035	36.3	50.5	43.1	21.0	32.4	26.2	32.8	42.1	37.3	13.8	19.4	16.4	17.6	24.1	20.6	34.4
2036	35.0	48.5	41.2	19.1	29.5	23.8	32.4	41.7	36.8	12.9	18.1	15.3	16.9	23.0	19.8	33.7
2037	34.5	47.4	40.7	19.0	28.4	23.5	32.8	42.0	37.3	13.2	17.9	15.4	17.3	23.3	20.2	34.5
2038	36.3	49.9	43.0	20.6	31.1	25.5	31.6	40.6	36.2	12.7	17.6	15.0	16.8	22.7	19.7	33.2
2039	35.0	47.8	41.0	20.0	30.5	24.7	31.3	40.2	35.8	12.2	16.9	14.5	16.7	22.6	19.6	32.6
2040	33.0	45.4	38.8	18.8	28.0	23.2	30.4	39.5	35.2	11.7	16.5	13.9	16.6	22.6	19.4	31.7
2041	31.8	43.9	37.8	18.8	27.9	23.0	30.1	39.2	34.4	12.5	17.3	14.6	17.0	23.2	19.7	31.4
2042	34.2	47.5	40.8	21.6	32.3	26.4	28.7	38.0	33.2	12.6	17.6	14.9	17.0	23.5	19.9	30.2
2043	33.2	45.4	38.6	21.3	31.9	26.7	28.4	36.9	32.4	12.4	17.2	14.6	17.0	23.0	19.8	29.8

Table 122. Average annual wholesale electricity prices for PNW by future (2023 $/MWh)

Year	RRHL	RRHR	RRLH	RRLL	RRLR	RRRH	RRRL	RRRR	RSHH	RSHL	RSHR	RSLH	RSLL	RSLR	RSRH	RSRL
2023	50.3	44.6	19.2	26.9	23.3	38.6	50.3	44.6	56.4	72.0	64.4	37.3	48.9	43.3	56.4	72.0
2024	39.7	34.4	17.1	25.2	21.1	29.0	39.7	34.5	46.0	60.5	53.4	34.1	46.1	40.5	45.7	60.4
2025	39.3	33.7	15.9	24.8	20.3	25.5	36.5	31.1	44.4	59.9	52.2	32.8	45.3	39.1	42.4	57.4
2026	41.0	35.1	16.9	24.9	20.8	26.2	37.0	31.5	46.5	61.6	54.5	34.2	46.0	40.3	43.7	57.7
2027	40.4	34.3	16.6	25.0	20.6	23.3	33.7	28.2	45.4	60.8	53.3	33.2	45.4	39.6	40.1	53.9

Year	RRHL	RRHR	RRLH	RRLL	RRLR	RRRH	RRRL	RRRR	RSHH	RSHL	RSHR	RSLH	RSLL	RSLR	RSRH	RSRL
2028	43.4	36.8	16.9	26.2	21.1	21.5	32.0	26.5	47.1	62.0	55.2	33.4	45.4	39.6	38.1	50.9
2029	45.2	38.4	16.3	26.6	20.9	20.5	31.3	25.5	47.9	63.8	56.4	32.9	45.2	39.1	37.2	50.0
2030	46.0	38.8	16.3	26.5	20.9	20.1	30.9	25.0	47.7	63.7	56.0	32.4	44.5	38.4	36.2	49.1
2031	47.1	39.5	15.9	26.5	20.6	19.5	30.8	24.5	49.0	64.8	57.1	32.3	44.4	38.5	35.9	48.5
2032	46.6	39.4	15.4	25.4	20.0	18.8	29.5	23.8	47.7	63.7	55.8	30.5	42.8	36.5	34.1	46.9
2033	48.2	41.0	15.4	25.7	20.1	18.9	29.8	23.9	49.1	65.1	57.2	30.7	42.6	36.5	34.3	46.8
2034	46.6	40.1	15.4	24.5	19.6	18.6	28.6	23.2	48.9	63.8	55.9	30.2	41.6	35.8	33.8	45.7
2035	46.8	40.4	14.9	23.9	19.0	18.9	28.7	23.5	48.9	63.7	56.0	29.7	40.8	35.0	33.9	45.6
2036	46.1	39.5	14.0	22.0	17.5	17.9	26.9	22.0	47.8	63.0	55.6	27.9	39.0	33.5	32.1	44.2
2037	46.0	40.0	14.3	21.7	17.6	18.4	27.2	22.4	47.8	62.4	55.2	27.5	38.3	33.0	32.1	43.8
2038	44.4	38.6	13.8	21.1	17.1	17.8	26.3	21.6	46.2	60.4	53.5	26.5	37.1	31.9	31.0	42.7
2039	43.8	37.9	13.3	20.3	16.5	17.7	26.0	21.4	45.8	59.9	53.0	25.9	36.3	31.2	31.0	42.3
2040	43.0	37.5	12.8	19.5	15.8	17.7	25.9	21.3	43.9	58.7	51.2	24.3	34.7	29.5	29.5	41.6
2041	42.6	36.8	13.5	20.7	16.7	18.1	26.5	21.9	43.3	57.8	50.7	25.0	35.2	30.1	30.0	41.5
2042	41.0	35.4	13.7	20.5	16.7	18.1	26.3	22.0	41.4	55.7	48.5	24.3	35.1	29.6	29.1	40.9
2043	40.1	34.7	13.5	20.3	16.7	18.1	26.2	21.8	41.0	54.5	47.6	24.5	34.3	29.3	29.4	40.5

Table 123. Average annual wholesale electricity prices for PNW by future (2023 $/MWh)

Year	RSRR	SRRH	SRRL	SRRR	SRHR	SRHL	SRHH
2023	64.3	40.7	52.9	47.1	47.2	52.8	40.8
2024	53.3	30.5	41.6	36.4	36.1	41.7	30.5
2025	49.9	26.8	38.4	32.7	35.5	41.3	29.1
2026	51.0	27.5	39.0	33.1	36.6	43.0	31.1
2027	47.7	24.3	35.3	29.6	36.2	42.5	30.1
2028	44.9	22.5	33.4	27.7	38.5	45.4	32.4
2029	43.6	21.4	32.8	26.8	40.3	47.5	33.3
2030	42.5	21.0	32.5	26.2	40.9	48.2	34.0
2031	42.4	20.3	32.1	25.4	41.2	49.1	34.2
2032	40.4	19.6	30.8	24.7	40.9	48.5	34.4
2033	40.5	19.8	31.2	24.9	42.8	50.2	35.6
2034	39.6	19.4	30.0	24.1	41.7	48.5	35.4
2035	39.5	19.6	30.3	24.3	42.1	48.8	35.5
2036	38.1	18.7	28.2	23.3	41.1	48.0	35.4
2037	38.1	19.3	28.2	23.5	41.6	47.7	36.1
2038	36.8	18.7	27.4	22.7	40.6	46.1	34.8
2039	36.8	18.5	27.0	22.4	39.9	45.5	34.3
2040	35.4	18.5	26.9	22.4	39.4	44.8	33.3
2041	35.8	19.0	27.5	22.9	38.4	44.4	33.0
2042	35.0	18.9	27.4	23.0	37.0	42.7	31.6
2043	34.8	19.0	27.2	22.8	36.2	41.8	31.1

H.1.2 Aurora PGE Zone Model

The Aurora PGE Zone Model (PZM) is used to simulate the economic dispatch of existing PGE and candidate new resources. Inputs to the model are:

- Variable costs and operating characteristics of PGE existing resources, power plants, and contracts, generally matching those of the 2022 annual update tariff (AUT) November 15 filing. An exception is planned maintenance and forced outages that represent our best estimate of plant's long-term performance instead of the snapshot of the test year of AUT.
- Fuel prices match those of the WECC model except for Colstrip, for which we have more detailed assumptions
- Carbon dispatch adders matching those of the WECC model
- Electricity hourly wholesale prices for the Pacific Northwest are simulated with the WECC model.

Aurora simulates PGE existing dispatchable generation resources, contracts, and new resources using economic dispatch based on electricity prices and associated risk variable inputs consistent with each price future. When economically dispatched, resources will generate when resource dispatch cost is lower than the electricity market price and will not generate when market purchases are cheaper.

The PZM outputs are sources of inputs to ROSE-E for all price futures across all years. ROSE-E inputs new resources' capacity factor and energy value, existing resources' variable costs and energy value, and existing portfolio's baseline resource costs and baseline net contract costs from PZM, the set of PZM outputs to ROSE-E includes total annual variable costs, annual net market purchases, resource dispatch, and energy value for new and non-carbon emitting resources. The dispatch results of the thermal units in various price futures from the PZM are provided to the Intermediary GHG model, described in greater detail in **Appendix H.2, Intermediary GHG model**.

H.2 Intermediary GHG model

PGE buys and sells power on the wholesale market for various reasons, including risk mitigation and net variable power cost reduction. Incorporating HB 2021 into planning requires differentiating between energy and associated emissions used to serve retail load, and energy and emissions used for wholesale market sales. To accomplish this, the 2023 IRP uses an Excel-based intermediary GHG model.

The intermediary GHG model focuses exclusively on GHG emitting generation. Its objective is to allocate GHG emitting power to retail load service and to wholesale sales. The model takes inputs from:

- Aurora for thermal units, based on economic dispatch and various price futures
- Historical data for market transaction patterns
- The Oregon DEQ for GHG intensity values from emitting sources (tons / MWh)

Using these inputs, the model creates estimates for how much power PGE can retain from each specific source to meet retail load under different GHG constraints. Total power plant dispatch ratios and historical sales patterns determine the amount of each resource retained for retail load service, keeping similar ratios across fuel types. For example, historically, PGE keeps a greater percentage of natural gas generation for retail load service than coal generation. Resultingly, in the model, natural gas generation is kept for retail load service at a higher rate than coal. Inside fuel classes (natural gas, coal, etc.) the ratio of power retained for retail load service is the same across resources. An example of this is in **Table 124**, using power plants Beaver and Carty and focusing on the year 2027. In this example, 77 percent of the plant output for both Beaver and Carty is kept for retail load.[465]

Table 124. Example retail/wholesale energy breakout in 2027

Resource	Total MWh	Retail MWh	Retail %
Carty	2,477,916	1,901,681	77%
Beaver	563,811	432,698	77%

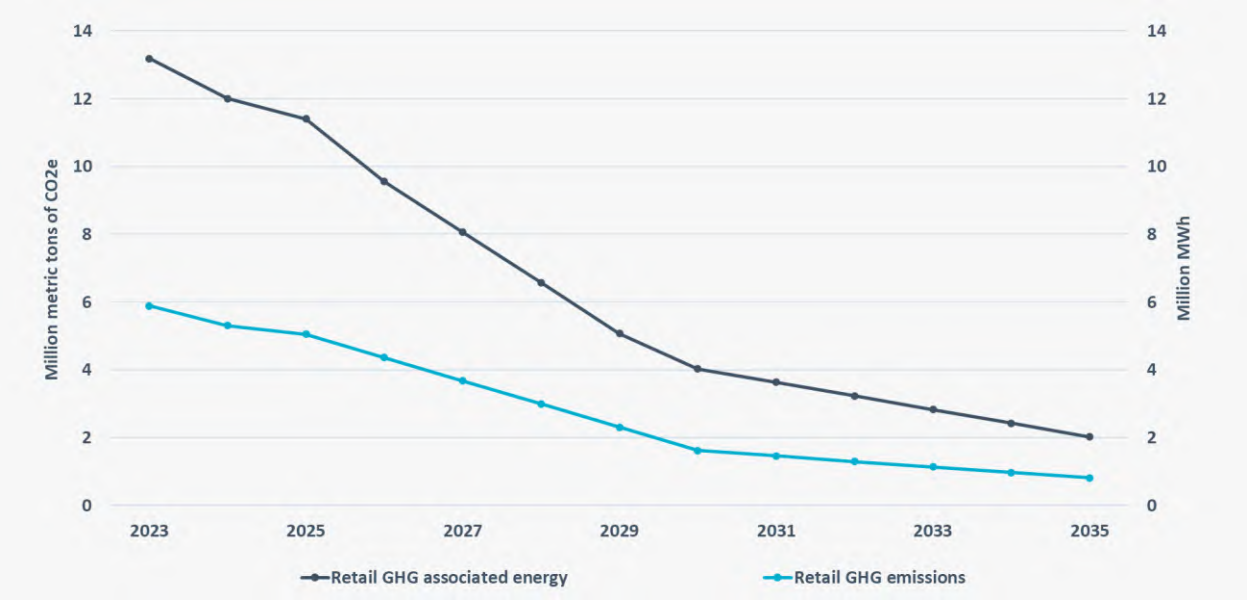
In the example shown in **Table 124**, the total MWh values are determined by the Aurora model, which provides the thermal plant inputs to the intermediary GHG model. The model then reduces the amount of generation retained for retail load (in this case down to 77 percent) while taking other resource emissions and GHG targets into consideration.[466] The generation not retained for retail load is assumed to be sold into the wholesale power market.

The primary output of the intermediary GHG model is the total amount of generation from GHG emitting resources retained for retail load.[467] This information helps set the energy

[465] Example data, actual values used in the IRP may differ.
[466] The 2023 IRP uses five different GHG glidepaths (targets). More information on the glidepaths is in **Chapter 5, GHG emissions forecasting**.
[467] Distributed system generation resources are not in the GHG model or IRP energy position. These resources typically dispatch under emergency conditions. Inclusion of DSG resources at 2022 dispatch levels was tested in the GHG model and resulted in a 2030 annual energy position change of under 0.1 MWa.

position for ROSE-E, the IRP capacity expansion model. An example of this is in **Figure 132** which shows GHG emitting resource energy and emissions retained for retail load service. More discussion on the model is in **Chapter 5, GHG emissions forecasting**.

Figure 132. Retail load GHG emissions and associated energy (Reference Case)



H.3 Sequoia

This section provides a brief overview of the Sequoia model and focuses on changes made to Sequoia since the 2019 IRP Update.[468] For more detailed information about the model, see Appendix K of the 2019 IRP Update.

H.3.1 Overview

Sequoia runs stochastic simulations to test the PGE system for resource adequacy, perform Effective Load Carrying Capability (ELCC) studies, and examine GHG emissions. It pairs different load and resource profiles to test the power system under a wide range of conditions. A typical test simulates 50,000 weeks per season (summer/winter) to provide a

[468] 2019 IRP update with appendix K at p.75, available at: https://assets.ctfassets.net/416ywc1laqmd/1PO8IYJsHee3RCPYsjbuaL/b80c9d6277e678a845451eb89f4ade2e/2019-IRP-update.pdf

broad set of load and resource combinations. The model runs on an hourly timestep, with 50,000 weeks equating to 8.4 million hours.[469]

The Sequoia model runs each week independently. It starts with an initial draw of seven sequential historical days. From those days, it extracts three key inputs: the month, if the days are a weekday or a weekend, and the daily load bin (the load bin tells the model how high loads are). Using this information, Sequoia builds a synthetic week. The key pieces of the week are:

- Water year, which sets the weekly energy budget and hourly generation max/min for large hydropower projects. The model uses the same water year for the entire week. The water year data come from a historical 30-year record, with the data being specific by month.
- Load profile. The load profile changes daily and aligns with the initial draw data by month, weekday/weekend, and load bin. The load data use 30 historical temperature profiles to create variations.
- Wind/solar profile. The wind/solar profiles, which are independent by project, change daily and align to the initial draw data by month and load bin. Matching the load bin values to the wind/solar profile links temperature to wind/solar generation outputs.
- Thermal generation availability is set using stochastic forced outage rates and mean-time-to-repair inputs. Thermal generation can also vary by month, with higher generation available in colder months due to air density.
- Storage resources start the week 100 percent charged, this a change from the 2019 IRP update that started storage at a 50 percent charge level. Storage resources charge and discharge as needed, with perfect foresight, and are limited to one cycle per day.
- Power market inputs vary by month, time of day, and load bin. More information on power market inputs is in **Appendix G, Market capacity study**.
- Other inputs, like demand response programs and run-of-river hydropower, enter the model via month-hour shapes (which use hourly shapes that vary by month and weekday/weekend) or monthly blocks (the resource output varies by month).

Table 125 visually represents part of the process previously outlined for one week in Sequoia.

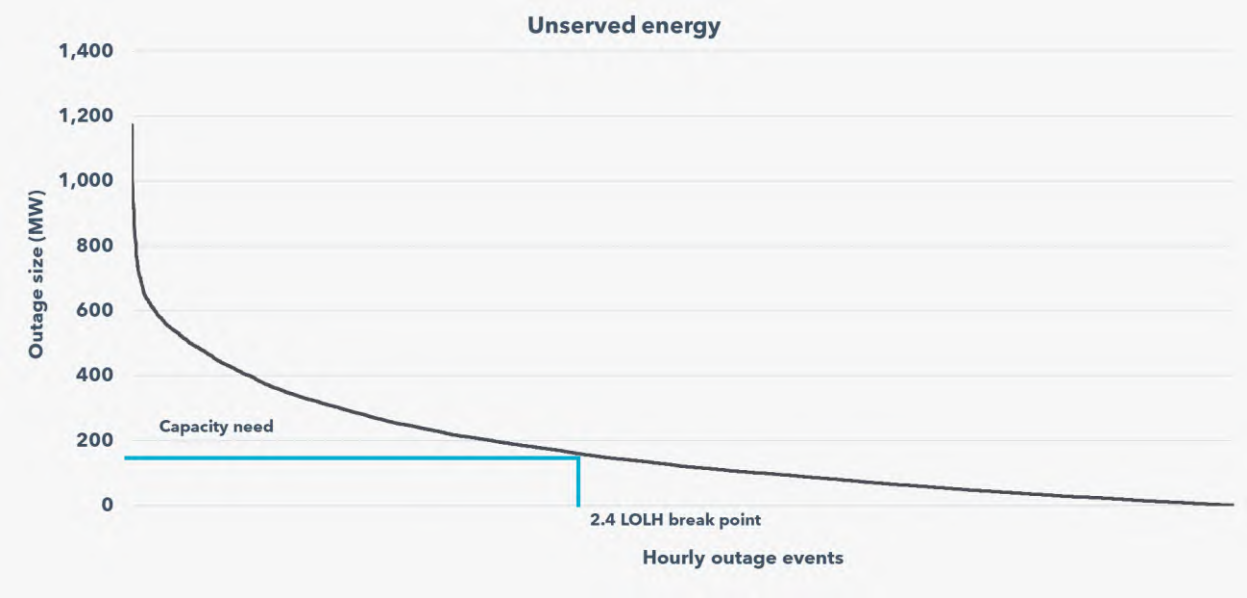
[469] 50,000 weeks are tested per year/season for capacity needs and to establish ELCC values. To reduce model runtime capacity needs in some years after 2030 are interpolated.

Table 125. Sequoia week creation example

Start date	Month	Load bin	Weekday	Water year	Biglow	Bakeoven	Load	Thermal resources
8/5/1997	8	5	1	2003	8/6/2005	8/11/2014	8/30/2007	Resource generation varies by month and by forced outage rate.
8/6/1997	8	5	1	2003	8/25/2016	8/3/2014	8/7/1981	
8/7/1997	8	5	1	2003	8/5/2010	8/10/2014	8/13/1992	
8/8/1997	8	3	1	2003	8/22/2005	8/24/2014	8/30/1991	
8/9/1997	8	4	0	2003	8/1/2005	8/9/2012	8/24/2019	
8/10/1997	8	5	0	2003	8/21/2011	8/26/2011	8/8/1987	
8/11/1997	8	5	1	2003	8/31/2004	8/19/2014	8/18/1981	

As the model runs, it tabulates when outages occur. Each outage enters a loss-of-load log, ranking outages from largest to smallest. The model then calculates the number of outage hours allowable to meet the 2.4 Loss of Load Hours (LOLH) target. It finds this value on the x-axis and outputs the corresponding capacity value on the y-axis. This value is the effective capacity needed to achieve an adequate system. If the system is already adequate, the value is zero. An example of this calculation is in **Figure 133** – in this case, the system needs around 200 MW of capacity.

Figure 133. Sequoia capacity need calculation example



PGE uses the Sequoia model to calculate resource ELCC values, using the following steps:

- The model runs once to establish a base system capacity need
- The model runs again with a new resource added and produces a new capacity need
- The difference in capacity need between the base system and the system with the new resource added determines how much effective capacity the resource contributes
- The effective capacity value is divided into the resource nameplate value to calculate the ELCC

This approach is similar to how the Northwest Power and Conservation Council determined resource capacity contributions in the 7th Power Plan (the Council calls this approach associated system capacity contribution or ASCC).

H.3.2 Sequoia input model changes since the 2019 IRP Update

Updates have been made to the Sequoia data inputs since the 2019 IRP Update. Select updates are in **Table 126**.

Table 126. Select input related Sequoia changes since 2019 IRP Update

Item	Update
Pelton/Round Butte	Hydropower contract renewed
Core load forecast	Updated spring 2022
Electrification loads	Updated summer 2022
Temperature years	Year 2021 included
Existing western solar profile	Updated with NREL data
Forced outage rates	Updated spring 2022
Qualifying facilities online	Updated spring 2022
DER inputs	Updated summer 2022
Power market availability	Updated market analysis
Run-of-river hydropower	Updated with BPA/Corps data
2021 Proxy RFP portfolio	Included

H.3.3 Other Sequoia model changes since the 2019 IRP Update

Since the 2019 IRP Update, Sequoia has undergone several non-input-related changes. They include:

- Running the model seasonally rather than annually. A seasonal ELCC provides more information for resource additions during portfolio analysis. With many resources, ELCC values differ by season. Using a seasonal approach can help ROSE-E, the capacity expansion model, better evaluate resource options and resource adequacy on a seasonal level. For example, Gorge wind tends to have higher ELCC values in the summer than winter. Resultingly, ROSE-E may see more value from Gorge wind if summer capacity needs are more prevalent than winter, and less value if winter needs are more prevalent than summer.

- Running the model to analyze GHG emission. Via an approach suggested by E3, a consultancy, Sequoia can provide insights into GHG emissions on the PGE system. **Appendix I, C-level analysis** discusses how the model runs for GHG emissions.
- Starting storage resources fully charged at the start of the week. More discussion regarding this change is in **Appendix J, ELCC sensitivities**.

H.4 ROSE-E

ROSE-E is a capacity expansion model that identifies resource additions across potential futures and years using information about PGE's capacity and energy need, operational and regulatory requirements, the current portfolio of resources, and technical and economic characteristics of new resource options. ROSE-E will select a portfolio of resources that satisfies the constraints imposed while minimizing the chosen objective. A full description of the model parameters and mathematical implementation can be found in Appendix I of the 2019 IRP.[470] This appendix focuses on changes and improvements made to ROSE-E since the 2019 IRP.

PGE has approached portfolio design in this IRP as a one-stage process where optimization and scoring have been combined into a single process that is focused on building a portfolio that allows PGE to comply with HB 2021. The previous IRP used a two-stage approach to create a variety of near-term portfolios based on alternative objective functions while minimizing Net Present Value Revenue Requirement (NPVRR) over the study period for any given near-term build.

H.4.1 Input data

Changes and improvements have been made since the 2019 IRP to methodology associated with some of the inputs that ROSE-E receives from other PGE models.

Existing resources

The source of information on PGE's existing resources has evolved since the 2019 IRP because of the new planning paradigm associated with HB 2021. To forecast PGE's future energy position, ROSE-E utilizes a load-resource balance (LRB) model (**Section 6.5, Energy need**). Energy from non-GHG emitting resources in the LRB is determined by estimated capacity factors. Energy from thermal plants and GHG-associated market purchases are

[470] In the matter of Portland General Electric Company, 2019 Integrated resource plan, Docket No. LC 73, Order No. 20-152, available at: https://apps.puc.state.or.us/orders/2020ords/20-152.pdf

estimated using the Intermediary GHG model. More information in **Section H.2, Intermediary GHG model**.

Baseline portfolio

Total variable costs and annual net market purchases for the Baseline Portfolio are generated by the Aurora PGE Zone simulation and factor into portfolio costs and energy-related constraints in ROSE-E. To follow the established DEQ emission methodology, market sales and market purchases are estimated using data from Aurora in conjunction with the Intermediary GHG model, which is used to determine the amount of GHG-associated energy that is retained to serve Oregon retail load, and how much is available for wholesale market sales.

Temporal granularity

The temporal granularity of certain inputs has been increased to add realism to model assumptions or provide additional modeling flexibility.

Resource adequacy

To foster reliable portfolios, ROSE-E utilizes data from Sequoia that defines the amount of accredited capacity needed to maintain a reliable system, which is defined as LOLE of 2.4 hours per year (see **Chapter 6, Resource needs**). In the 2019 IRP, capacity need data was defined at the annual level.[471] To capture the difference more accurately in system needs throughout the year, the capacity need is calculated seasonally (summer and winter) in Sequoia. ROSE-E must build sufficient resources to be adequate in both seasons. Effective Load Carrying Capability (ELCC) of new resource options is also calculated seasonally in Sequoia.

Flexibility value

Flexibility values have previously been static throughout the study period and can now vary across all years of the analysis. Flexibility value of storage resources was calculated for years 2026 and 2030. In ROSE-E the 2026 value is linearly interpolated for the years 2027 - 2029, and the 2030 value is linearly interpolated from 2031 – 2043. See **Ext. Study-IV, Flexibility study** for a detailed description of flexibility values.

[471] In the matter of Portland General Electric Company, 2019 Integrated resource plan, Docket No. LC 73, Order No. 20-152, available at: https://apps.puc.state.or.us/orders/2020ords/20-152.pdf

New types of resource options

Portfolio analysis in the 2023 IRP includes three types of resource options that have not been included in previous IRPs. The following describes these new types of resource options.

Non-cost-effective EE and DR

As in the 2019 IRP, cost-effective Distributed Energy Resources (DERs) are accounted for as reductions in forecasted load, as described in **Appendix D, Load forecast methodology**. In this IRP, Energy Efficiency (EE) and Demand Resources (DR) that do not meet the cost-effectiveness criteria have been added as new resource options to be considered for selection by the model alongside supply-side options in portfolio analysis.

CBREs

Three types of community-based renewable energy (CBRE) resources are included as resource options in portfolio modeling. More information about CBREs is provided in **Section 7.2, Community-based renewable energy (CBRE)**.

Transmission expansion

Three options to expand transmission capacity are available for selection in the model. These options are described in detail in **Section 9.4.1, Proxy transmission options identify transmission need.**

Generic Resources

The model has access to two generic non-emitting resources (Generic Capacity and Generic VER). These resources give the model sufficient access to energy and capacity to meet system needs that would otherwise be infeasible in a transmission-constrained environment. The generic resources are priced slightly higher than the most expensive supply-side resource available to the model.

H.4.2 Constraints

In addition to the four constraints identified in the 2019 IRP, constraints have been added to accommodate new planning requirements or issues of increasing relevance.

Emissions

All ROSE-E portfolios are subject to an GHG emissions constraint that limits portfolio emissions to levels that comply with HB 2021 emissions targets. Except in the case of portfolios designed specifically to test the impact of alternative GHG reduction glidepaths, emissions targets are defined using the linear glidepath (**Section 5.3, Components of IRP emissions reporting**). The generation from existing PGE thermal plants made available in ROSE-E is limited to levels that produce emissions up to the levels associated with HB 2021 targets each year. The allocation between plants is determined by economic dispatch up to the emissions limit in each price future (**Section 5.3, Components of IRP emissions reporting**). Because the GHG budget is fully utilized up the GHG emissions reduction glidepath with the dispatch of PGE-owned thermals and GHG-emitting contracts/market purchases, gaps between energy needs to serve retail load and energy allowed to serve it must be made up through the building of new non-emitting resources, without the option to utilize market purchases beyond what is accounted for in the Intermediary GHG emissions model.

Transmission

A new constraint imposes limits on transmission availability to move energy from new off-system resources to PGE's system. Previous IRPs assumed all proxy resource builds would be able to deliver their energy to PGE's system. In the 2023 IRP, we incorporated the current contractual transmission landscape by assigning an inventory of transmission availability for each resource that limits the total quantity of each resource that can be built. Resource inventories are quantified in MWs of available transmission capacity (ATC) defined by zones, with cross-zonal impacts accounted for in the calculation of inventory quantity. Therefore, resource builds within a given zone do not impact the availability of transmission in other zones.[472] Resource transmission zones and the methodology used to determine available transmission inventories are described in **Section H.7, BPA transmission in ROSE-E**.

Each resource zone has an inventory of available firm transmission and an inventory of conditional firm transmission availability.[473] On-system resources do not have transmission limitations and do not impact the inventories of other resources.[474]

[472] For example, Gorge Wind and Wasco Solar are both in the Gorge transmission zone, which has 190 MW of LTF ATC. So, building 1 MW of either Gorge Wind and Wasco Solar reduces the LTF ATC of the Gorge zone to 189 MW, but does not impact the ATC of either a) the ATC of other transmission zones or, b) the CF ATC of the Gorge zone.
[473] Resources available with firm transmission generally have higher ELCC values than those with conditional firm transmission (as described in **Appendix K, Tuned system ELCCs**).
[474] Storage resources and CBREs are considered on-system.

H.5 LUCAS

H.5.1 LUCAS – Levelized fixed-cost revenue requirement tool

The Levelized Utility Cost Aggregator System (LUCAS) is a tool used to calculate revenue requirements for the fixed costs of new supply-side resources and PGE-owned resources. LUCAS is an Excel-based model. Significant inputs to LUCAS include:

- Financial assumptions. PGE's cost of capital required return, long-term inflation, tax rates (federal, state, and property), federal investment tax credits, and the Modified Accelerated Cost Recovery System (MACRS) schedule.
- PGE-owned resources. PGE's book and tax depreciation, economic life, deferred tax, fixed O&M, scheduled capital additions, and fixed gas transportation costs.
- Supply-side resources. Includes overnight capital costs, fixed operations & maintenance (O&M), project life, decommissioning costs, and plant operating parameters. As applicable, LUCAS captures fixed costs for gas transportation and wheeling.

For a given resource, LUCAS calculates the total fixed costs for each year, the net present value of those costs across the project's life, and the real-levelized cost. Outputs from LUCAS include real-levelized fixed costs for each resource option by commercial operation date (COD) and capital cost trajectory. These data are passed to ROSE-E for determination of the fixed component of portfolio costs and evaluation of resource economics.

H.5.2 Long-term financial assumptions

As required by Guideline 1a of Order No. 07-002, PGE's estimated after-tax marginal weighted average cost of capital of 6.25 percent serves as a proxy for the long-term cost of capital to discount future resource costs. PGE bases this estimate on information available as of Q1 2022. **Table 127** contains other relevant financial assumptions.

Table 127. 2023 IRP long-term financial assumptions

Component	Percent
Composite Income Tax Rate	27.5%
Incremental Cost of Long-Term Debt[475]	3.9%
Long-Term Debt Share of Capital Structure	50.0%

[475] The incremental cost of long-term debt is based on an average of three-year forward 30-year borrowing costs as of March 2022 (i.e., the cost of 30-year debt in 2022, 2023, and 2024).

Component	Percent
Common Equity Return	9.5%
Common Equity Share of Capital Structure	50.0%
Weighted Cost of Capital	6.7%
Weighted After-Tax Discount Rate	6.2%
Long-Term General Inflation	2.1%

H.6 Annual Revenue-requirement Tool (ART)

The Annual Revenue-requirement Tool (ART) is an Excel-based tool used to estimate the annual revenue requirement ($'s) and the normalized annual revenue requirement ($/MWh) impact for a set of portfolios. ART was developed in addition to ROSE-E and the differences between the two models are listed in **Table 128**.

Table 128. Differences between ROSE-E and ART

	ROSE-E	ART
Costs:	Existing and new resource related fixed, variable, and integration costs based on 100% PPA assumption	Existing and new resource related fixed, variable, and integration costs based on different ownership structures
Benefits:	Includes all resource benefits such as - energy value, flexibility value, RCBI	Only includes monetary benefits of wholesale market sales when generation is higher than load
Other:	All values are expressed in levelized terms which may not reflect actual yearly costs due to ownership structure and tax credit implications	All values are based on expected impact each year of the planning horizon, and are representative of the cost changes associated with existing and incremental generation

Figure 134 and **Figure 135** show a simplified version of the governing equation within ART to assess the annual revenue requirement or price impact.

Figure 134. Estimating the annual price impact ($)

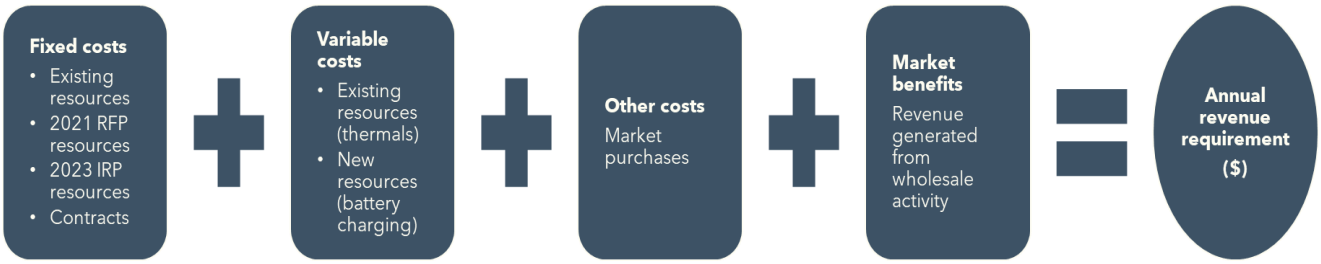
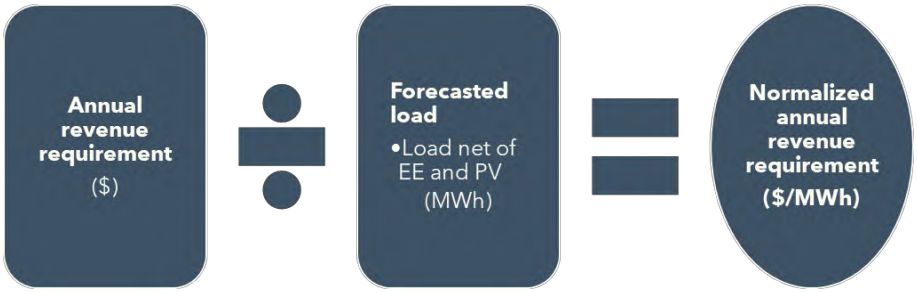


Figure 135. Estimating the annual normalized price impact ($/MWh)



Each component of **Figure 134** and **Figure 135** along with their corresponding source is detailed in the following:

- **Fixed costs** in ART represent the aggregate impact of fixed costs stemming from each of the following:
  - Existing resources – The fixed costs of existing resources include costs such as the capital carrying costs, depreciation, taxes, demand response program cost, and costs of Energy Trust programs. These are aggregated and sourced from the LUCAS model (**Section H.5, LUCAS**).
  - Contracts – Cost of Qualifying Facilities are calculated on a $/MWh basis within Aurora and included within ART. Additionally, costs of other contracts are aggregated and sourced from LUCAS.
  - 2021 RFP proxy resources – For the 2021 RFP, costs of PGE's Clearwater Wind project are included from 2024. Costs of the remainder of the 2021 RFP start in 2025 and are estimated through proxy solar and battery resources. PGE assumes 100 percent PPA for these resources.
  - 2023 IRP – The magnitude and timing of resources is sourced from ROSE-E (**Section H.4, ROSE-E**), while cost streams for both ownership and power purchase agreement (PPA) assumptions are sourced primarily from LUCAS.

- **Variable costs** in ART include the cost of running thermal units which primarily include fuel costs and the cost of charging batteries. Both of these costs come from the Aurora PGE zone model (PZM).
- **Other costs** include purchases PGE makes from the spot market for both specified and unspecified sources. These are calculated within the intermediary GHG model (**Section H.2, Intermediary GHG model**).
- **Market benefits** represent the benefits from wholesale sales which are calculated in part within the intermediary GHG model and through the load resource balance output from ROSE-E. These benefits are calculated yearly using yearly average prices.
- **Forecasted load** represents the load in MWh net of load reducing DERs including energy efficiency and rooftop solar.

The limitations of and assumptions used in ART are as follows:

- ART only include generation related costs and does not include costs from the rest of the company such as grid modernization, administration & general (A&G), wildfire mitigation, or PGE transmission & distribution costs. Additionally, generation costs include both actuals and proxy costs. Proxy costs and associated operating characteristics may not be reflective of costs or project capabilities seen in future RFPs. Thus, ART does not reflect actual or expected customer prices and applying percentages to these changes will not represent actual customer price changes over time. Instead, ART provides directional impact of resource actions and another dimension when comparing portfolios.
- All costs are noted in nominal terms
- Yearly prices are highly sensitive to assumptions of generic resources costs
- Results are specific for the Reference Case scenario (reference need, reference prices, reference cost future)
- Assumes Colstrip exit in 2029
- Assumes the following Reference Case conditions:
    - Ownership – 50 percent PPA and 50 percent PGE ownership of all new resources and 100 percent PPA for the remaining 2021 RFP proxy resources. This impact affects tax credit allocations and payment schedule.
    - Energy efficiency and demand response costs are not securitized or financed, and impact customer prices in year one.
    - All tax incentives are monetized.

H.7 BPA transmission in ROSE-E

Through engagement with stakeholders, it was determined that PGE would incorporate transmission-related assumptions and modeling in this 2023 IRP. Availability of capacity on BPA's transmission system was included as a resource build constraint in ROSE-E. The amount capacity available on BPA's system was quantified through a review of BPA's published TSR Study and Expansion Process reports (TSEPs) from 2016-2021.[476] BPA has stated that TSRs made starting in 2022 will only be granted service once upgrades are complete.[477] Transmission capacity on BPA's system that is subject to upgrades is not included in the calculated available inventories.

TSRs (Transmission Study Requests) made prior to the 2022 TSEP that point to PGE's system were used to quantity the availability of BPA transmission to access PGE's system, according to the following criteria:

- Requested transmission service associated with TSRs in 'study' status are categorized as available conditional firm (CF) transmission.
- Requested transmission service associated with TSRs in 'confirmed' status are categorized as available long-term firm (LTF) transmission.

This inventory is used in ROSE-E as a constraint on the quantity of resource that can be built in different resource zones, as described in **Section H.4.2, Constraints**. Available inventory by zone used in ROSE-E is shown in **Table 129**, and the resource zone of each proxy resource is shown in **Table 130**.

[476] Available at: https://www.bpa.gov/energy-and-services/transmission/acquiring-transmission/tsep
[477] With the exception of 80 MW of transmission capacity for offshore wind BPA identified in the 2022 TSEP as available without upgrades, which is included in ROSE-E transmission inventories (**Table 129**).

Table 129. Transmission ATC by Resource Zone

Resource Zone	LTF	CF	Total
Christmas Valley	490	510	1000
Gorge	190	388	578
McMinnville	10	0	10
Montana	0	0	0
Offshore	0	80	80
SE Washington	0	150	150
Total	690	1128	1818

Table 130. Transmission Zones of Proxy Resources

Transmission Zone	Proxy Resource
Christmas Valley	Solar_CV
Christmas Valley	CV_Hyb_1
Christmas Valley	CV_Hyb_2
Gorge	Wind_Gorge
Gorge	Solar_Wasc
McMinnville	Solar_Mcm
McMinnville	MCMN_Hyb_1
McMinnville	MCMN_Hyb_2
Montana	Wind_MT
Offshore	Wind_Off
SE Washington	Wind_SEWA

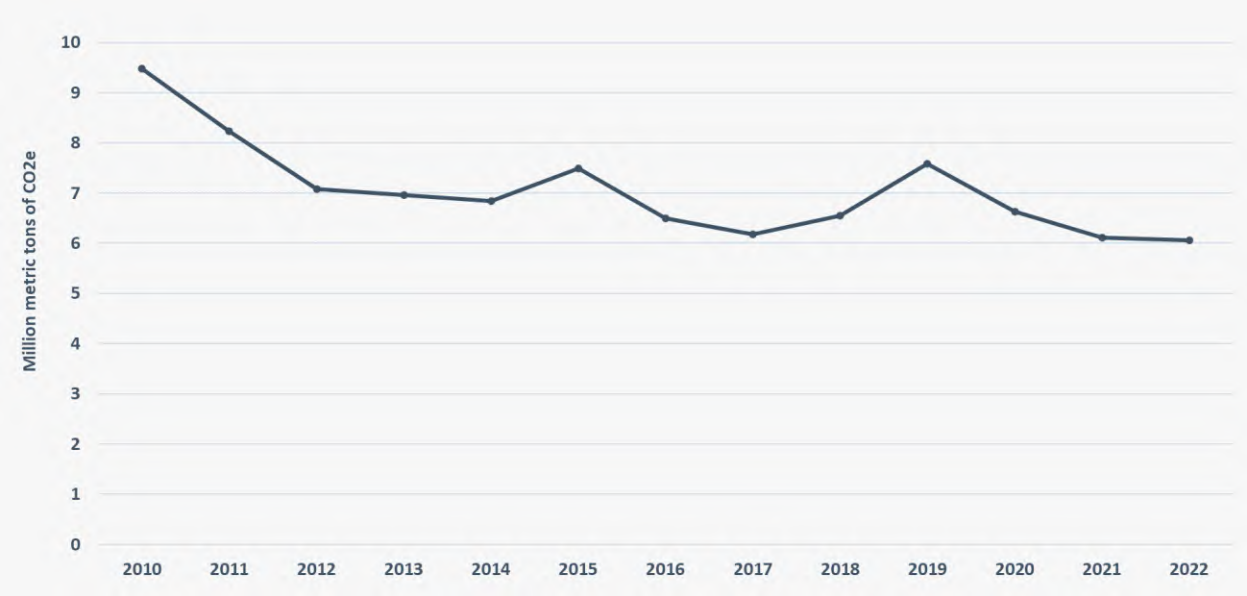
Appendix I. C-level analysis

This appendix discusses how GHG emission levels can vary on an annual basis due to weather, hydro conditions, and other factors. It starts by looking at historical variations, and then includes an analysis on potential variations in 2030 using the IRP Preferred Portfolio.

I.1 GHG variability in power systems

Figure 136 shows historical PGE system GHG emissions for retail load service from 2010 through 2022. In the historical data, there are annual variations in GHG outputs. These annual variations are often due to factors outside the control of PGE, like regional hydroelectric generation levels, and different weather patterns that impact temperature as well as wind/solar generation.

Figure 136. Historical PGE GHG emissions for retail load



Under HB 2021 PGE must emit 1.62 million metric tons of CO2e or fewer in 2030 for serving retail load, 0.81 MMT or fewer in 2035, and zero in 2040. A challenge in planning for the emissions targets is incorporating annual GHG emission variations. For example, in year 2030 PGE may have a power system that emits 1.62 MMT of CO2e under average conditions. But the same system may emit more GHGs under extreme temperature conditions. This is due to extreme temperatures typically requiring more electricity for heating and/or cooling needs, and the extra power likely coming from a GHG emitting resource. On the other hand, a year with mild weather may see lower GHG emissions due to decreased demand. Hydro

conditions also play a role in GHG emission variations. In years with higher-than-average hydropower generation there may be a reduced need to operate GHG emitting resources, and in lower hydropower generation years the need for GHG emitting generation may increase.

The Oregon Public Utility Commission (OPUC) has stated that utilities should "achieve the 2030 and 2035 clean energy targets under typical or expected weather and hydro conditions…"[478] This implies that system emissions may be higher or lower than the GHG targets due to variability, but on a one-in-two basis meet the targets. To better understand the range of GHG emissions due to temperatures and hydro variations, PGE performed a GHG variability assessment as part of the IRP. This is called a carbon-level, or C-level, analysis in the IRP.

The GHG variability assessment focuses on the annual impact of hydro and temperature variations on GHG emissions. It does not account for variability outside of temperature and hydro conditions, nor does it account for temperature and hydro excursions outside of the historical range. While it provides insight into GHG variations, actual system variations may differ.

The assessment has four steps:

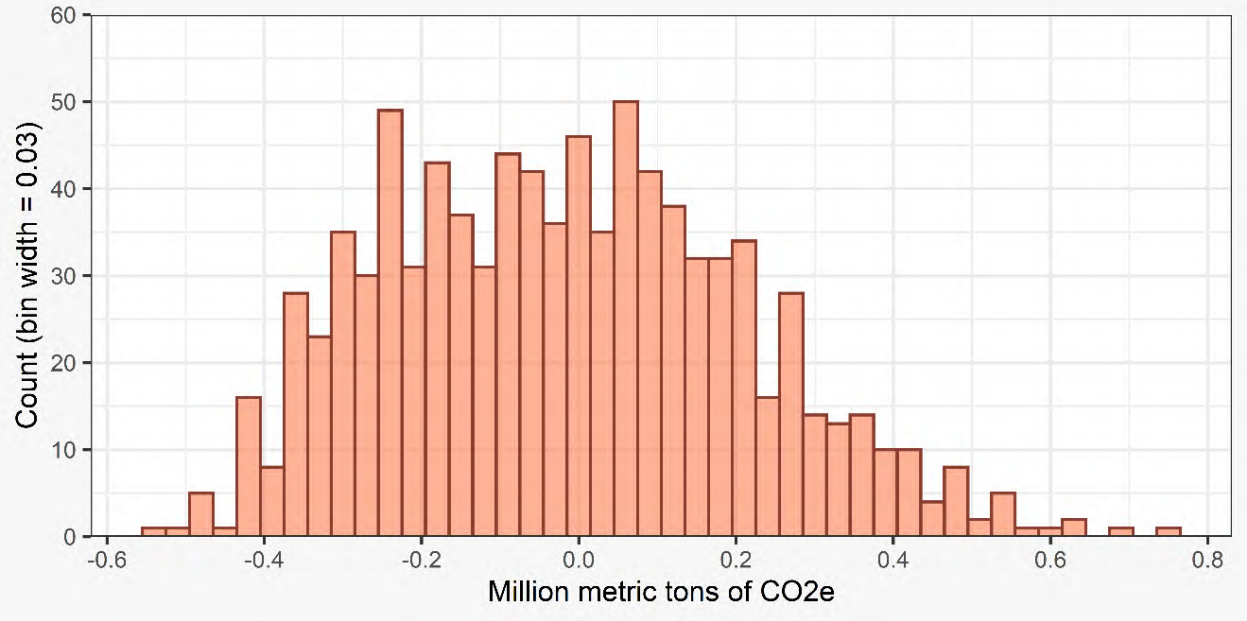
1. The Sequoia model estimates annual GHG variability from temperature utilizing its hourly dispatch logic and catalog of 30 temperature years. Based on a recommendation from consultant E3, Sequoia runs without thermal resources when performing this estimate to achieve GHG-free resource optimization. With thermal generation removed from the model, there are many hours in which load (demand) cannot be served by available generation (demand). These quantities of deficit are defined as unserved energy.
2. The MWhs of unserved energy in Sequoia are assumed to be met with GHG-emitting generation. The analysis assumes that this GHG-emitting generation has an intensity rate of 0.385 metric tons/MWh.[479] Annual GHG emissions are estimated by multiplying the MWhs of unserved energy in Sequoia by 0.385 tons/MWh. For example, if a year has 3 million MWhs of unserved energy, this is multiplied by 0.385 tons/MWh to arrive at an annual GHG emissions estimate of 1.155 million metric tons. The result is 30 different annual GHG estimates based on temperature variations.[480]
3. The impact of hydro variability on GHG emissions is estimated using a 30-year historical dataset. The annual median generation of the dataset is found, and the difference between each year and the median is calculated. Some years are higher than the median,

[478] Docket No. UM 2225, Order 22-446, at 31.
[479] 0.385 metric tons / MWh represents a mix of CCCT gas plants.
[480] For this analysis temperature years in Sequoia are created by grouping the initial draw data. The initial draw data sets the load bins, and Sequoia then pulls loads from the 30-year record within that bin. As a result, the synthetic load years will have similar, but not identical, temperature characteristics as the actual years.

others less than. For each year, a GHG value of 0.385 tons/MWh is assigned to each MWh of generation higher or less than the median. The result is 30 estimates of how hydro variations impact GHG emissions.

4. The hydro and temperature variations are paired together, creating 900 possible annual GHG variations, ranging from the mildest temperatures and highest hydro conditions (least GHGs) to the most extreme temperatures and lowest hydro conditions (highest GHGs). A histogram of the range is in **Figure 137**. The histogram shows the distribution of GHG emissions for retail load service above and below expected conditions in the Preferred Portfolio in year 2030. For example, the max value in the dataset is 0.74. This implies that there is a possibility of GHG emissions in 2030 being 0.74 million metric tons higher than the 1.62 million metric ton 2030 target (2.36 million metric tons).

Figure 137. GHG histogram from Preferred Portfolio



Using the data from **Figure 137**, PGE has created various GHG percentiles, known in the IRP as C-levels. The C-levels for year 2030 in the Preferred Portfolio are in **Table 131**. One way to use the data is to calculate how much extra GHG free energy PGE would need to acquire to shift the distribution and meet the 1.62 million metric tons of GHG target under a range of conditions. This is included in the right most column of the table, assuming each MWh of GHG free generation offsets 0.385 metric tons of GHG emissions.

Table 131. C-Level analysis

C-Level	MMT of CO2e (retail)	Million MWh of CO2e free energy needed to reach 1.62 MMT target
Max	2.36	1.93
90th percentile	1.90	0.73
75th percentile	1.76	0.36
Median	1.62	

The C-level analysis takes GHG variations from temperature and hydrological conditions into consideration. It does not include GHG variations from any other factors. As a result, the actual range of GHG variation is likely larger.

Appendix J. ELCC sensitivities

This appendix discusses effective load carrying capability (ELCC) values, portfolio interactions, and sensitivities. For general information on resource ELCCs in this IRP, see **Chapter 10, Resource economics**, and for information on the Sequoia model, see **Appendix H, 2023 IRP modeling details**.

The base assumptions in the Sequoia model changed over the course of 2023 IRP modeling due to resource changes, load changes, and stakeholder feedback. Some of these sensitivities ran earlier in the process with previous model versions. As a result, readers should focus on the directionality of the change in the sensitivities rather than the absolute values.

J.1 ELCC and resource portfolios

PGE uses the Sequoia model to calculate resource ELCC values, using the following steps:

- The model runs once to establish a base system capacity need.
- The model runs again with a new resource added and produces a new capacity need.
- The difference in capacity need between the base system and the system with the new resource added determines how much effective capacity the resource contributes.
- The effective capacity value is divided into the resource nameplate value to calculate the ELCC.

The 2023 IRP tests resource ELCCs in the year 2026. The base 2026 power system for ELCC testing has a resource deficit of 429 MW in the winter and 506 MW in the summer.[481] ELCCs can be calculated untuned, with a system deficit, or tuned, where the base power system has had resources added until it is resource adequate or nearly adequate. For portfolio creation PGE runs ELCC studies in an untuned system. Portfolio creation ELCC values for each resource are located at the end of this appendix. PGE also runs a tuned ELCC study that includes the IRP Preferred Portfolio. Tunned ELCC values are in **Appendix K, Tuned system ELCCs**.

Some resources, like batteries or pumped hydropower storage, may have lower ELCC values when tested in untuned systems. This is due to not having sufficient energy to charge. For

[481] Due to input changes the ELCC base system in the winter has a need 1 MW lower than the final 2026 need (which is 430 MW in the winter). PGE staff tested changes in ELCC values at 100 MW of resource added with the updated model and found an average change of less than 1 percentage point and a max change of 2 percentage points. Due to the small size of these changes untuned ELCC values were not rerun.

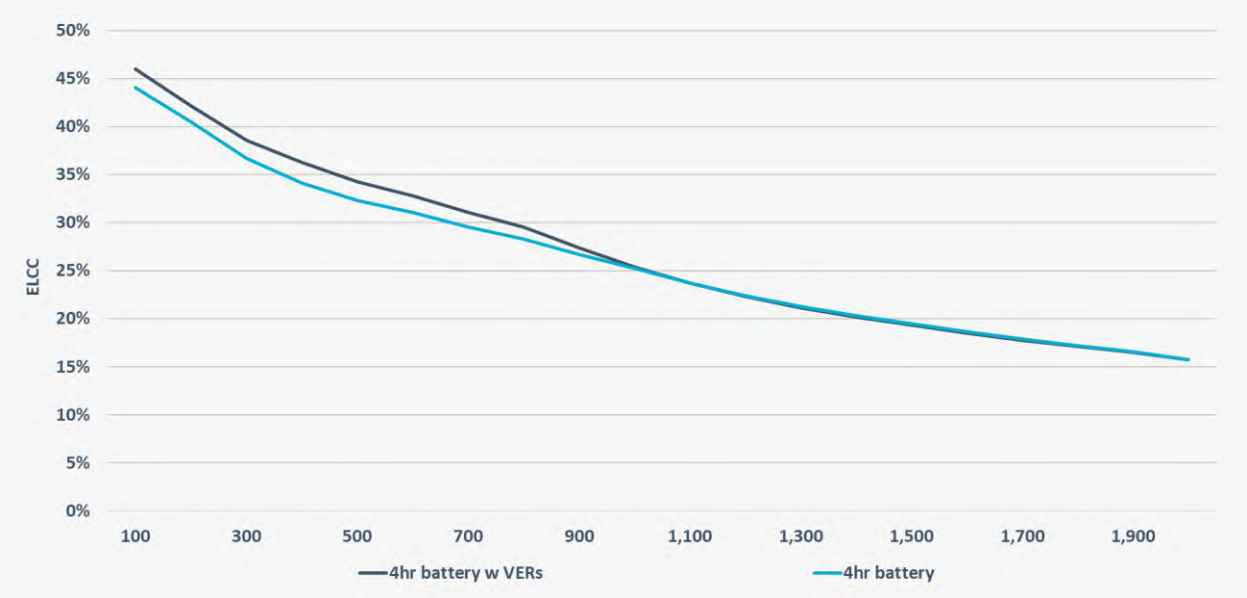
example, a battery might typically charge at night when tested in a relatively adequate, tuned system. But in an untuned deficit system, there may not be power available to charge at night, reducing the battery's ability to provide power the next day during key hours.

The 2023 IRP took two steps to provide more energy to batteries for charging when running untuned ELCC studies:

- Sequoia runs hourly in one-week increments. For the 2023 IRP, the starting charge state of storage at the beginning of the week is 100 percent rather than 50 percent used in the 2019 IRP Update. This adds additional energy into storage resources to help offset reduced charging ability in the untuned system.
- Increased the light-load hour market floor from 200 MW to 400 MW (initial modeling in the 2023 IRP used 200 MW as the light-load-hour floor). This gives storage more energy to charge from at night, to reflect a system/West with surplus energy during low-demand hours.

Beyond the two steps outlined previously, PGE also tested but did not include running untuned storage ELCCs with additional wind & solar added to the resource mix. In the test around 100 MWa of energy was added from a mix of wind and solar proxy resources. The model was then run to test winter 4-hr battery ELCCs. **Figure 138** shows an increase in 4-hr battery ELCC values with VERs as compared to 4hr battery in the Reference Case. The largest increase in the test is 2 percent, the average increase is 1 percent. PGE will continue investigating how to best model storage ELCC values in future planning work.

Figure 138. Winter 4hr battery with and without VERs



J.2 ELCC & transmission products

Transmission assumptions play a role in determining resource ELCC values. Many IRP resources require transmission over the BPA system. The IRP models two Bonneville Power Administration (BPA) transmission products, firm, and conditional firm with up to 200 hours of curtailment (CF200). Less than firm transmission products, like CF200, tend to produce lower ELCC values relative to firm transmission.

The Reference Case IRP approach to modeling CF200 transmission is to curtail the resource during the highest 100 hours of load per year. Since high-load hours are correlated with outages, the loss of resources in those hours reduces ELCC values. Other modeling approaches to CF200 transmission may yield different results.[482]

The IRP tests three CF200 transmission sensitivities. The sensitivities vary the hours curtailed by CF200 transmission from 100hr (Reference Case) to 200hrs, 50hrs, and 25hrs. The impact of these curtailment levels is tested on 300 MW of Gorge Wind and McMinnville Hybrid proxy resources. In all cases, increasing the number of hours curtailed reduces the resource ELCC value. The results, including the IRP reference values for firm transmission and 100hr of curtailment, are shown in **Figure 139** and **Figure 140**.[483]

[482]There is uncertainty on how to model CF200 transmission, for constancy the IRP takes the same approach as the 2021 PGE RFP, Docket No. UM 2166, Order No. 21-320, Appendix A page 24, available at: https://apps.puc.state.or.us/orders/2021ords/21-320.pdf

[483] These tests ran with an earlier version of the Sequoia model. The ELCC values may not align with the final values in the IRP. The directionality of the values should be the focus for the reader.

Figure 139. Conditional firm sensitivities, Gorge Wind, 300 MW

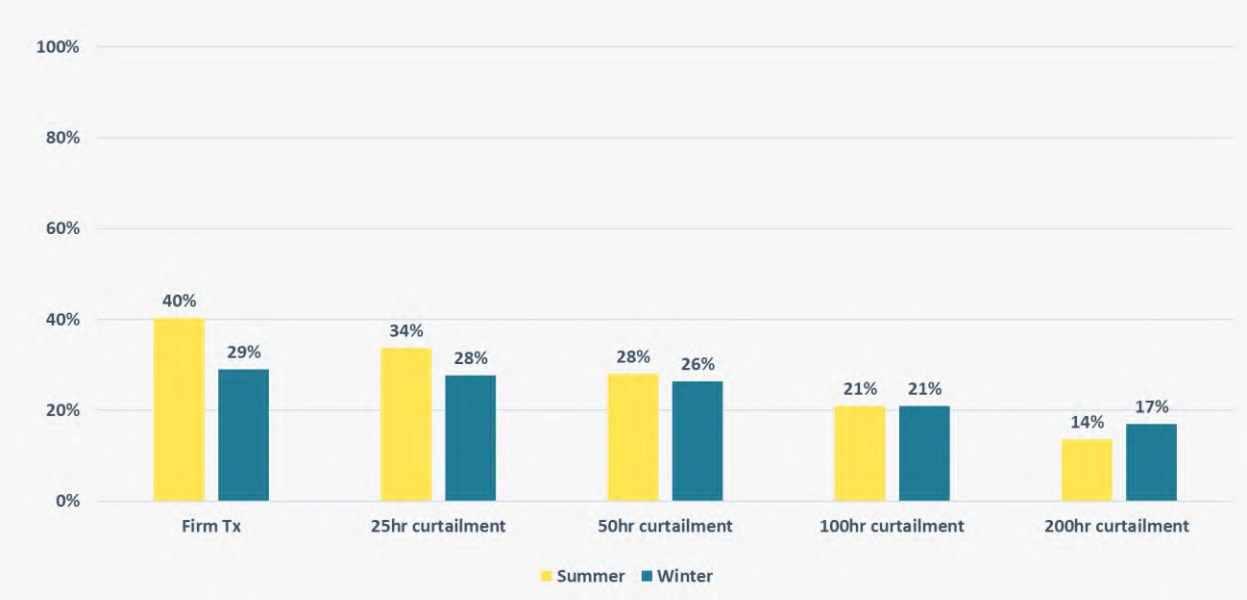
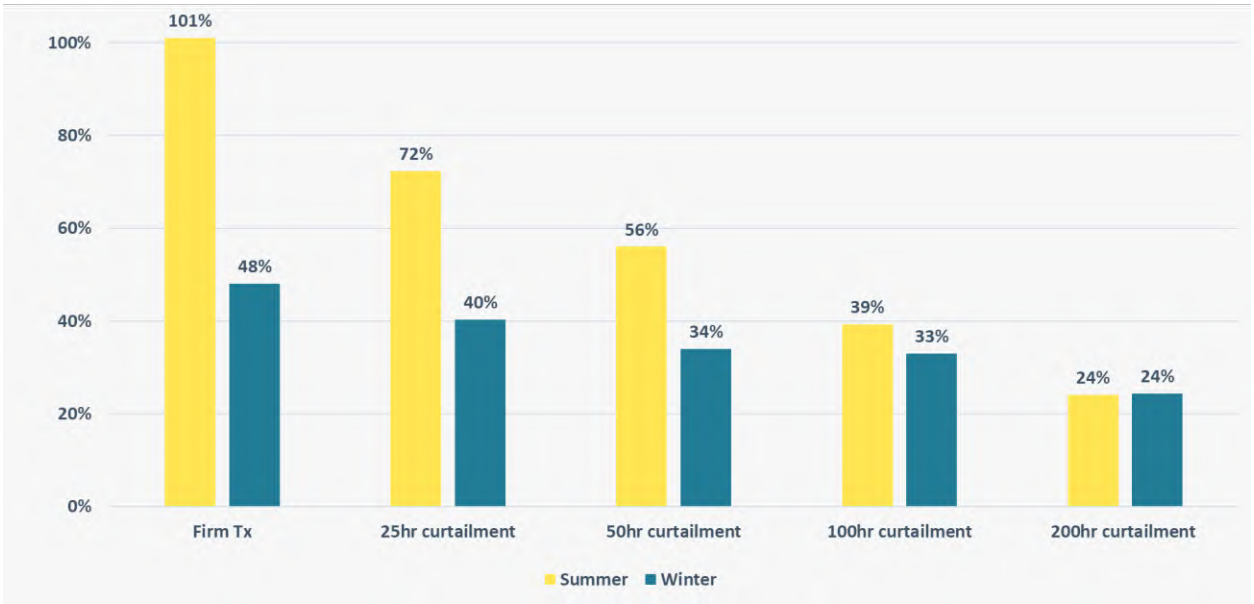


Figure 140. Conditional firm sensitivities, McMinnville Hybrid, 300 MW[484]



[484] ELCCs of over 100 percent can be achieved, typically due to the resource meeting need and providing energy for charging storage / saving hydropower.

PGE will continue to explore conditional firm transmission modeling options going forward. The CF200 modeling approach in the Reference Case, curtailing the top 100 load hours per year, is used due to uncertainty on modeling the product and a desire to maintain consistency with the 2021 RFP. Uncertainty on the CF200 transmission product arises since:

- Past curtailments are not a good indicator of future curtailments since sales of the CF200 product continue, leading to higher levels of transmission use
- BPA no longer posts conditional firm transmission available transmission capacity (ATC) inventories, making it challenging to assess future levels of system use
- BPA has not provided guidance on how to model the CF200 product

J.3 ELCC and resource characteristics

The 2023 IRP uses proxies to evaluate new resource options. These proxies are representative of new resources but do not represent the full range of options. To help study different solar facility specifications, the IRP tests the impact of solar inverter loading ratios (ILR) on ELCC values. A solar ILR describes the amount of DC solar panels in relation to the projects AC inverter. For example, a project with 134 MW of DC panel and a 100 MW AC inverter has an ILR of 1.34.[485]

Higher ILRs are beneficial for maximizing solar facility output. By collecting more solar irradiance, higher ILR facilities provide steadier/higher power output in cloudy conditions, during early morning and late evening hours, and higher output in the winter. During some hours, this higher output leads to clipping. Clipping occurs when the panels are capturing more solar power than the inverter size. Clipping generally increases when the ILR increases. The primary disadvantage to higher ILR for solar projects is higher costs due to the extra panels.

Figure 141 shows the annual hourly capacity factors of two solar facilities – one with the IRP default ILR of 1.34 and the other with a 1.50 ILR. Both sites use the Christmas Valley solar location. On an annual average basis, the 1.34 ILR project has a capacity factor of 28.0 percent, whereas the 1.50 ILR project is at 29.9 percent.

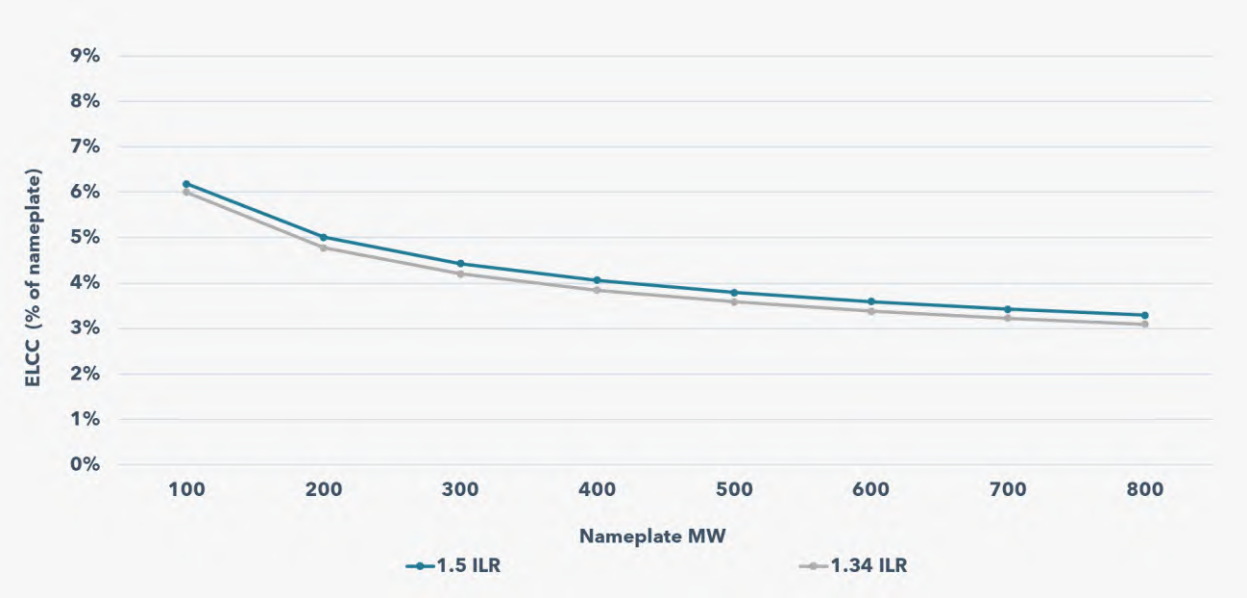
[485] 1.34 is the 2023 IRP default for utility scale stand-alone solar, utility scale hybrid projects in the IRP used a 1.50 ILR.

Figure 141. Annual hourly solar capacity factors by ILR

To test the impact of ILR on ELCC values, Sequoia analyzed both projects. The results are shown in **Figure 142** for 100 to 800 MW nameplate of resource added to the model. Over all eight resource tranches, the 1.50 ILR resource has higher ELCC values than the 1.34 ILR resource.[486]

[486] These tests ran with an earlier version of the Sequoia model. The ELCC values may not align with the final values in the IRP. The directionality of the values should be the focus for the reader. These results were shared in the April 2022 PGE Roundtable meeting.

Figure 142. Solar ILR ELCC test, Christmas Valley



For the 2023 IRP, PGE uses a stand-alone solar facility proxy with an ILR of 1.34 to comport with the NREL ATB data.[487] Additionally, the value of 1.34 is similar to values used by other Northwest utilities, as shown in **Table 132**. The table also includes the ILR value out of a more recent National Renewable Energy Laboratory (NREL) report, which moves the ILR down to 1.28. In part due to stakeholder requests, and in part due to DC coupling reducing the clipping issue, the utility scale solar-hybrid resource proxy has an ILR of 1.50.

Table 132. Inverter loading ratio in NREL and Northwest power planning documents

Source	Value	Notes
NREL 2020 ATB	1.34	Report released in 2021
NREL 2021 ATB	1.28	Report released in late 2021
PacifiCorp 2021 IRP[488]	1.30	Reduced from 1.46 in prior IRP based on industry trends - page 191

[487] The PGE IRP solar assumptions point to 2020 NREL data (released in early 2021). The 2021 NREL data (released in late 2021) use a solar ILR of 1.28. Available at: https://www.nrel.gov/docs/fy22osti/80694.pdf
[488] See page 191, available at: https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2021-irp/Volume%20I%20-%209.15.2021%20Final.pdf

Source	Value	Notes
Puget Sound Energy 2021 IRP[489]	1.20	"All solar resources were modeled with a DC to AC ratio of 1.2" - page 55 appendix D
Idaho Power 2021 IRP	1.30	Discussed in February 2022 UM 2022 PUC Staff meeting
PGE 2023 IRP value	1.34	Proxy resource based on 2020 Q1 NREL study
NWPCC 2021 Power Plan[490]	1.40	Samples a range of IRPs/studies – only source higher than 1.3 is PAC from 2019 IRP (PAC has reduced value since)

J.4 IRP portfolio creation ELCC ladders

The following figures show the ELCC values of IRP proxy resources out to 2,000 MW nameplate run in an untuned 2026 system for IRP portfolio creation purposes. ELCC values calculated in a tuned system are available in **Appendix K, Tuned system ELCCs**. **Figure 143** and **Figure 144** shows the ELCC values of wind resources in the IRP.

[489] Available at: https://www.pse.com/-/media/PDFs/IRP/2021/appendix/Appendix_B-M_Complete.pdf?sc_lang=en&modified=20220307202833&hash=EFC80E908F117D14A97A30322D88AFAC
[490] Available at: https://nwcouncil.app.box.com/s/kp0c6w5ivhqvge20bg3j40rsm13hyy1h

Figure 143. Summer wind ELCCs

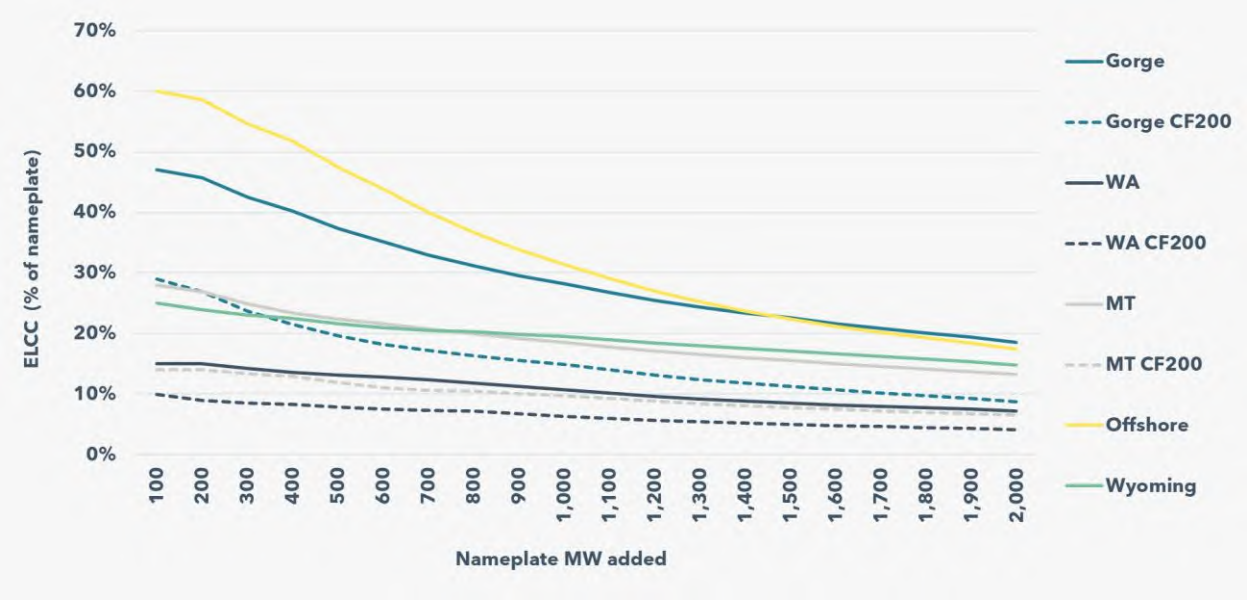


Figure 144. Winter wind ELCCs

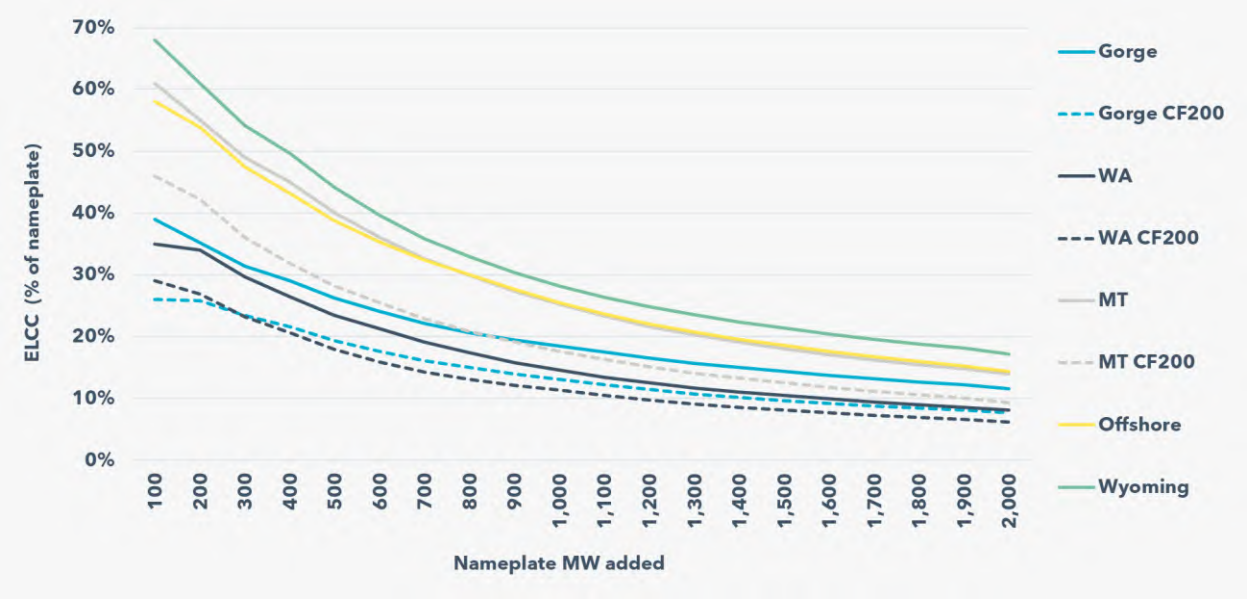


Figure 145 and **Figure 146** shows solar ELCC values in the 2023 IRP.

Figure 145. Summer solar ELCC

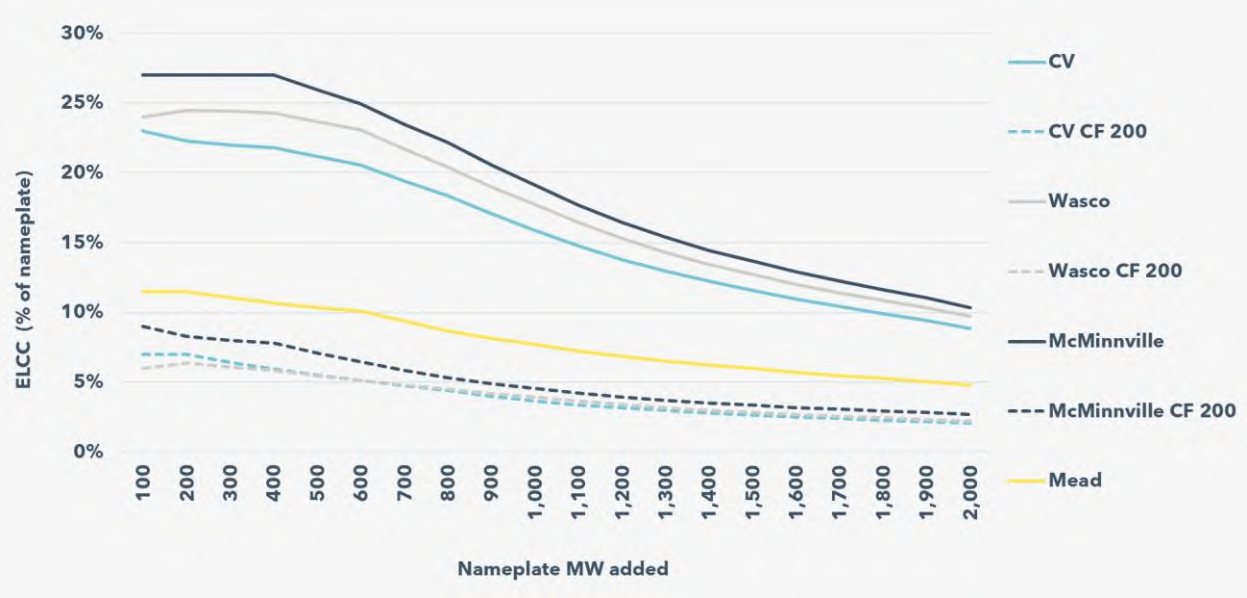


Figure 146. Winter solar ELCC

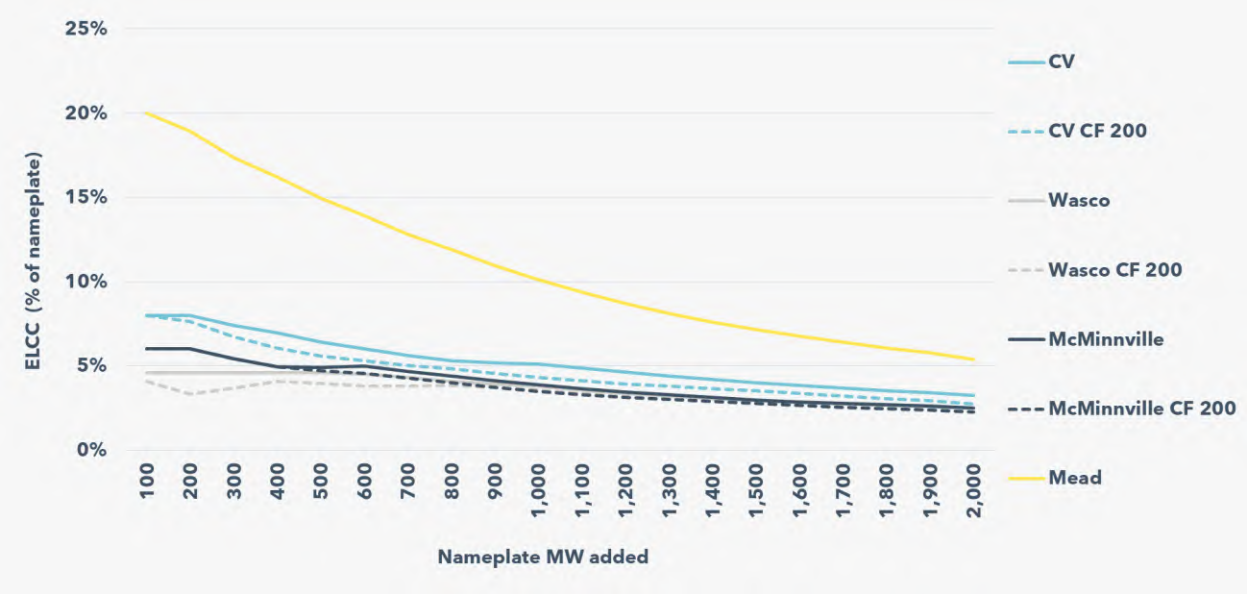


Figure 147 and **Figure 148** shows storage ELCC values.[491] Note that with pumped storage hydropower, the model entirely solves all adequacy issues before reaching the 2,000 MW

[491] Some resources, like pumped storage hydro, have ELCC values greater than 100 percent in the summer. This is generally due to the resource starting fully charged, bringing additional energy to the system.

nameplate of the resource. Once the model solves out, ELCC values are reduced by 1 percent for each subsequent 100 MW of resource.

Figure 147. Summer storage ELCC

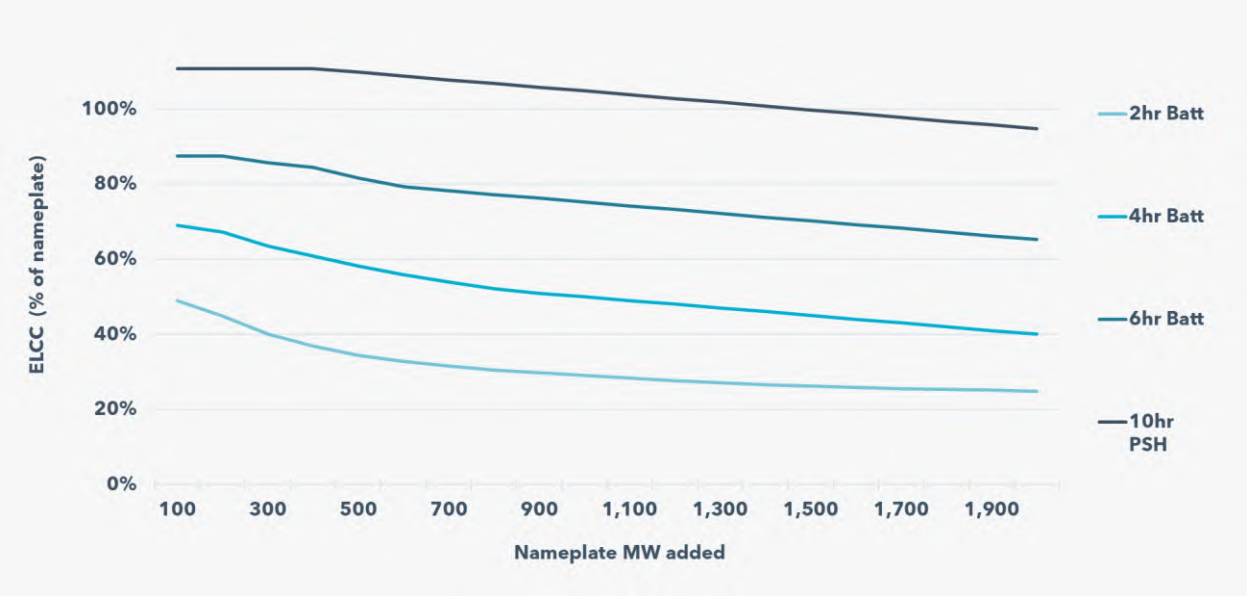


Figure 148. Winter storage ELCC

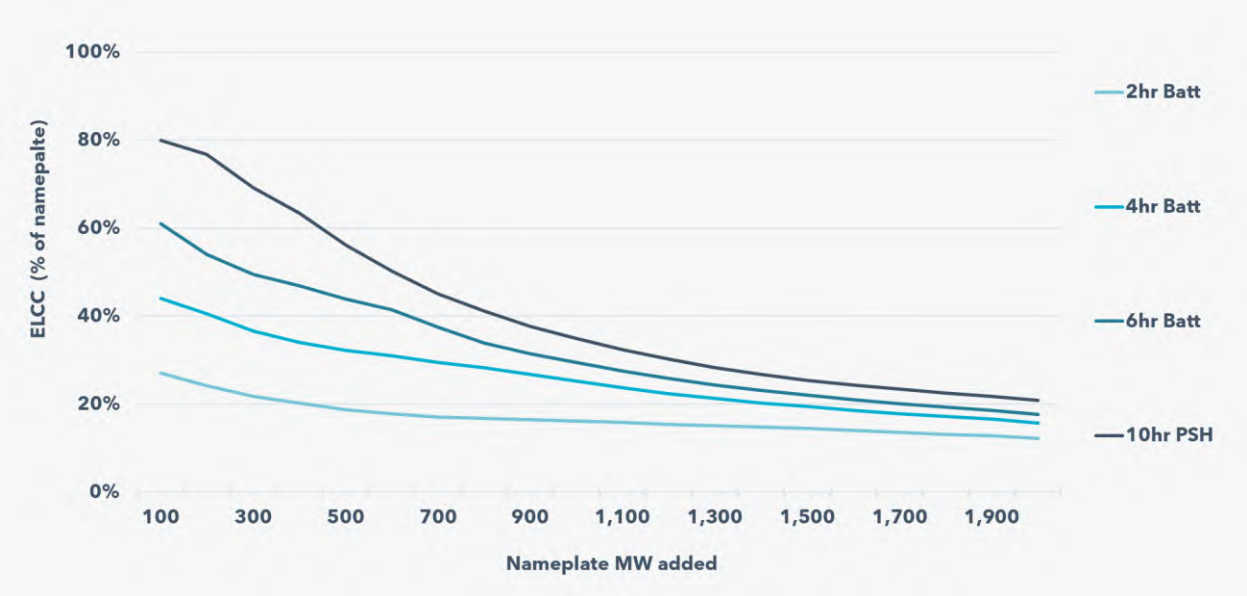


Figure 149 and **Figure 150** shows hybrid resource ELCC values. Some hybrid resources solve all adequacy issues before reaching the 2,000 MW nameplate of the resource. Once the model solves out, ELCC values are reduced by 1 percent for each subsequent 100 MW of resource.

Figure 149. Summer hybrid ELCC

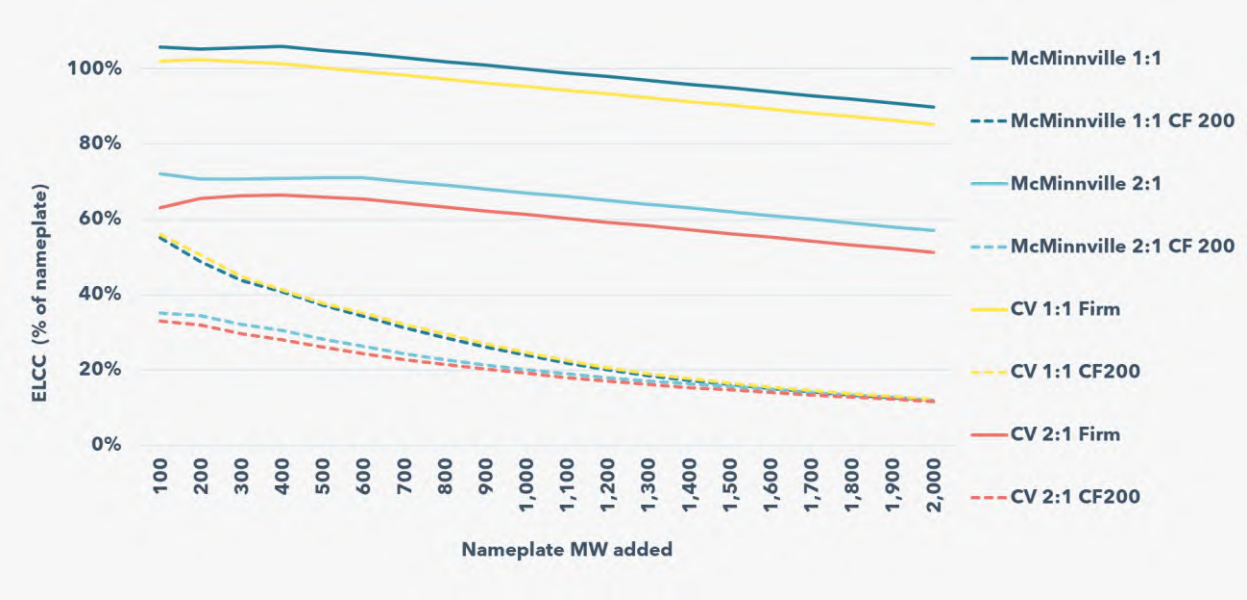
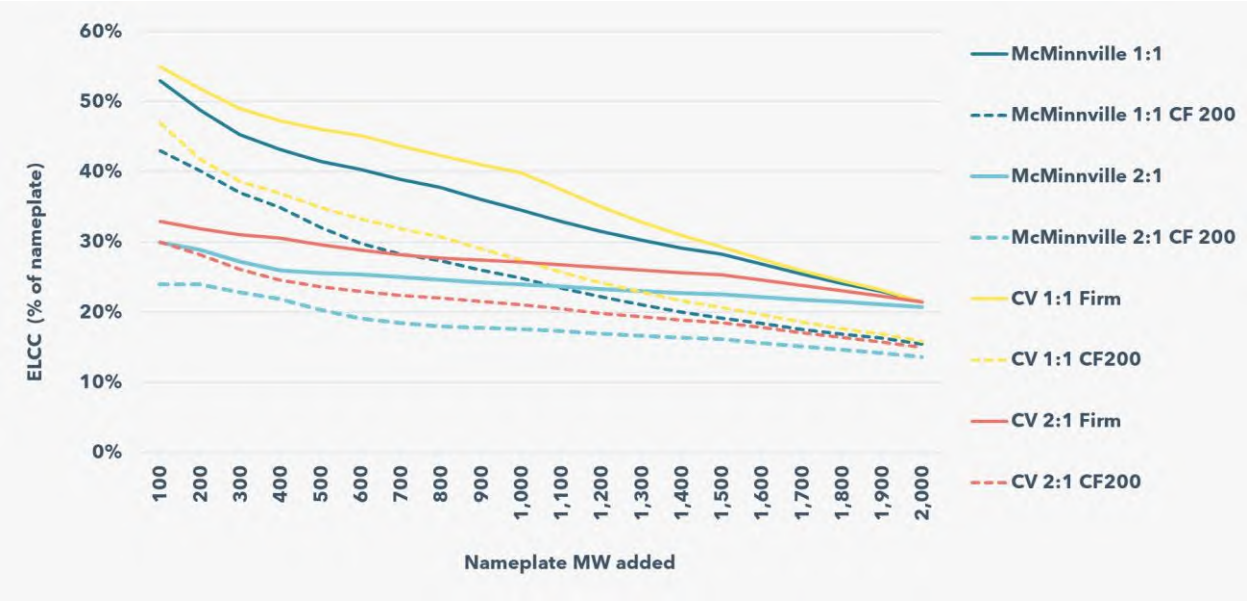


Figure 150. Winter hybrid ELCC



Appendix K. Tuned system ELCCs

This appendix provides tuned system ELCC values using the IRPs Preferred Portfolios. Tuned ELCC values are calculated in a model that is resource adequate or close to resource adequate. They provide an estimate of the resource's ELCC value when viewed as part of a complete system. Untuned values, which are used in this IRP for portfolio creation, are tested on a resource deficit system. Additional discussion on tuned vs. untuned ELCCs is available in the previous appendix.

K.1 Tuned system ELCCs

Annual tuned effective load carrying capability (ELCC) values are provided in line with the preferred practices recommended by the Oregon Public Utility Commission (OPUC) via the UM 2011 docket and to comply with LC 73 requirements.[492] The UM 2011best practices document applies "when calculating the capacity contribution of a supply or demand side resource, generally whenever a specific resource or resource type and not a portfolio of resources is being considered (incremental vs portfolio capacity analysis). This currently includes some aspects of regulatory purposes such as administrative pricing, cost effectiveness and customer program design, resource adequacy analysis, planning (IRP & DSP), and procurement (RFP)."[493]

The ELCC values in this section are calculated using a tuned system and at an annual level.[494] The tuned system includes IRP Preferred Portfolio resources and is adjusted by either adding or removing resources until the system deficit is around 70 to 100 MW.[495] The tunning is performed by adjusting up or down the level of perfect capacity resources in the portfolio (other resource types, like wind, solar, or battery, are not adjusted). After system tunning the ELCC studies run using the steps described in **Appendix J, ELCC sensitivities**. These values are not directly comparable to ELCC values used for portfolio creation in the IRP. The

[492] The LC 73 requirement is on page one of appendix A at: https://apps.puc.state.or.us/orders/2021ords/21-129.pdf The UM 2011 practices are here: https://apps.puc.state.or.us/orders/2022ords/22-468.pdf

[493] *Id.*

[494] For general information on resource ELCCs in this IRP, see **Chapter 10, Resource economics, Appendix J**, **ELCC sensitivities**, and for information on the Sequoia model, see **Appendix H, 2023 IRP modeling details**.

[495] If deficits become too low some resources, like hybrids, may solve all the outage hours required to return the system to an adequate state and thus not receive an accurate ELCC estimate. If the deficit is too high this negates the advantage of testing in a tuned system, which is examining how the resource behaves in a plausible future portfolio. The 70 to 100 MW range provides headroom for testing ELCCs of 100 MW increments of resource while staying inside a relatively adequate system. More discussion on why a tuned portfolio is used can be found in the best practices report: https://apps.puc.state.or.us/orders/2022ords/22-468.pdf

portfolio creation values are calculated in an untuned system and on a seasonal (as opposed to annual) basis.

The results are for 100 MW of supply side resource available in the Action Plan period from 2026 through 2043. ELCC values are calculated in year 2026, 2031, 2036, and 2043, with the years between linearly interpolated.[496] For reference, the average ELCC value from 2026 to 2043 is also included.

[496] This method comes from UM 2011 recommended best practices. "At a minimum, the IRP index of proxy resources must include at least four ELCC modeling year resource capacity contribution values. Unless otherwise warranted, the first ELCC modeling year shall be the first year where a major resource need is identified, and the last ELCC modelling year shall be the last year of the study period. The other two modelling years shall be selected by the utility, after considering input from Staff and stakeholders. Years of the study period not directly modelled shall have the ELCC annual capacity contribution values derived through interpolation using a reasonable method given the findings if the ELCC modelling analysis."

Table 133. Tunned ELCC values by year

Resource	2026-2043 avg.	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Wind Gorge Firm	15%	22%	20%	18%	15%	13%	13%	13%	14%	14%	14%	14%	14%	14%	14%	13%	13%	13%	13%
Wind Gorge CF200	10%	17%	15%	13%	10%	8%	8%	8%	9%	9%	9%	9%	9%	9%	9%	8%	8%	8%	8%
Wind SE WA Firm	19%	20%	19%	18%	17%	16%	16%	16%	17%	17%	17%	17%	18%	19%	20%	21%	22%	23%	24%
Wind SE WA CF200	14%	13%	13%	13%	13%	13%	13%	13%	13%	12%	12%	12%	13%	14%	15%	16%	17%	18%	19%
Wind MT firm	31%	39%	37%	36%	34%	32%	31%	30%	29%	28%	27%	26%	27%	28%	29%	29%	30%	31%	32%
Wind MT CF200	22%	23%	23%	24%	24%	24%	23%	23%	22%	21%	21%	20%	20%	21%	21%	22%	22%	23%	23%
Solar CV Firm	7%	22%	18%	14%	9%	5%	5%	5%	5%	5%	5%	5%	5%	4%	4%	3%	3%	2%	2%
Solar CV CF200	3%	10%	8%	6%	4%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	1%	1%	1%	1%
Solar Wasco Firm	9%	22%	19%	16%	12%	9%	9%	8%	8%	7%	7%	6%	6%	6%	6%	6%	6%	6%	6%

Resource	2026-2043 avg.	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Solar Wasco F200	4%	9%	8%	6%	5%	3%	3%	3%	4%	4%	4%	4%	4%	4%	4%	3%	3%	3%	3%
Solar MCMN Firm	10%	21%	19%	16%	14%	11%	11%	10%	10%	9%	9%	8%	8%	7%	7%	7%	7%	6%	6%
Solar MCMN CF200	4%	8%	7%	6%	5%	4%	4%	4%	4%	4%	4%	4%	4%	3%	3%	3%	3%	2%	2%
MCMN hybrid 1 Firm	67%	65%	66%	66%	67%	67%	67%	68%	68%	68%	69%	69%	68%	68%	67%	66%	65%	65%	64%
MCMN hybrid 2 Firm	39%	44%	43%	42%	41%	39%	39%	39%	39%	38%	38%	38%	38%	37%	37%	37%	37%	36%	36%
MCMN hybrid 1 CF200	53%	47%	48%	49%	50%	51%	52%	52%	53%	54%	54%	55%	55%	55%	55%	55%	55%	55%	55%
MCMN hybrid 2 CF200	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	29%	29%	29%	29%

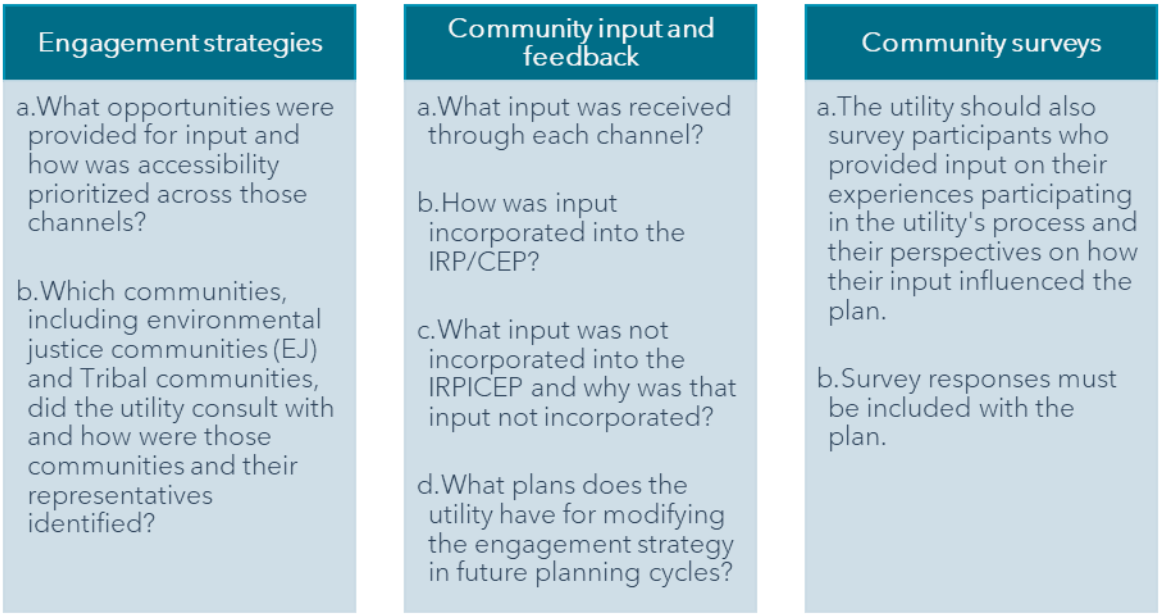
Resource	2026-2043 avg.	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
CV hybrid 1 Firm	67%	64%	65%	66%	67%	68%	69%	69%	70%	70%	71%	71%	70%	69%	68%	66%	65%	64%	63%
CV hybrid 2 Firm	39%	46%	45%	44%	42%	41%	41%	40%	40%	39%	39%	38%	38%	37%	37%	36%	36%	35%	35%
CV hybrid 1 CF200	53%	46%	47%	49%	50%	51%	52%	53%	54%	55%	56%	57%	57%	56%	56%	56%	56%	55%	55%
CV hybrid 2 CF200	30%	28%	29%	30%	31%	32%	31%	31%	30%	29%	29%	28%	29%	29%	30%	30%	31%	31%	32%
Two hr. battery	31%	20%	23%	25%	28%	30%	31%	32%	34%	35%	36%	37%	36%	35%	34%	32%	31%	30%	29%
Four hr. battery	56%	39%	43%	47%	51%	55%	56%	58%	59%	60%	62%	63%	62%	61%	60%	60%	59%	58%	57%

Appendix L. Clean Energy Plan: Learning Labs community feedback

The Oregon Public Utility Commission's (OPUC) Order 22-390 established requirements for utilities to ensure the "effectiveness of community engagement" during the development of Clean Energy Plans (CEP). PGE built upon the community engagement approach, initiated through the Distribution System Planning (DSP) process, in response to these CEP requirements. We recognize that the traditional process for developing the Integrated Resource Plan (IRP) is complex. It requires communication of dense, technical details that support the recommendation of a Preferred Portfolio of resources and that communication occurs in a relatively compressed timeframe, i.e., it caters to a technical audience. We initiated a new series of meetings, Community Learning Labs, to create space for education on IRP topics and to explore new topics introduced through the CEP guidelines.

The CEP community learning lab is the non-technical venue PGE created to socialize CEP-related concepts. During the development of the OPUC's community lens requirements for UM 2225, we heard that community input should be a "principal factor in determining what is in the public interest" for the CEP as well as transparency, accessibility, and understandability. Additionally, the CEP should bring benefit to environmental justice and other energy burdened communities, with an emphasis on Tribal communities. For this CEP, we sought to align with our community. This alignment included what we can do for the initial CEP and what we would like to work on with community over time. **Figure 151**, describes the OPUC's community engagement requirements.

Figure 151. OPUC Order 22-390 community engagement requirements



L.1 Engagement strategies

PGE approached Learning Lab topics iteratively, building up concepts over multiple workshops. When possible, PGE used relatable examples to make these concepts more relevant to the audience. Once a concept was defined, PGE would use Mural[497] to request specific feedback to help inform PGE's approach to the topic. CEP Learning Lab's target a non-traditional audience such as community service organizations, community-based organizations, municipalities, cities, OPUC Staff, Energy Trust of Oregon, and interested public members. From September to March, PGE held seven monthly workshops. During Learning Labs, we requested feedback on our approach, and in subsequent workshops, we reported how feedback was used to inform the CEP planning process. PGE also requested feedback via surveys and used the answers to modify Learning Labs. Modifications include changes such as the preferred length of the meeting and the virtual meeting platform to use for workshops (two-hour long, via Zoom).

[497] Mural is an online platform that allows for multiple people to participate at the same time. An example of a Mural excessive, available at: https://app.mural.co/t/distributionsystemplanpart27687/m/distributionsystemplanpart27687/1673469662755/11f19693ee09b53ee85f3f7b07bc1410b06f206a?sender=u293527aa870441a19c743984

Table 134 shows the CEP Learning Labs were attended by seven types of organizations and individuals from the community from September 2022 to March 2023. **Table 135** shows the topics covered throughout the six Learning Labs and how often each was visited.

Table 134. CEP Learning Lab attendance

Participants by type of organization	Total number of participants						
	17 Sep	13 Oct	20 Nov	7 Dec	7 Jan	12 Feb	10 Mar
Cities and municipalities	3	3	3	1	1	3	4
Climate Advocates	3	2	5		1	2	1
Community Service Organizations	1	1	2	1	1	2	1
Associations			1				
Energy Trust of Oregon	2	2	1	1	1	2	
Oregon Utility Board	1	2	1	1			1
Regulator	6	2	2	1		2	1
Individuals	1	1	5	2	3	1	2

Table 135. Topics covered during CEP Learning Labs from Sep 2022-Mar-2023

Topics covered	09/27/22	10/27/22	11/17/22	12/14/22	01/19/23	02/16/23	03/16/23
Integrated Resource Planning (IRP) Overview & IRP Roundtable updates	X	X	X	X	X	X	X
Community Engagement Strategy	X				X	X	X
Community Benefits Impact Advisory Group (CBIAG)	X				X		
Community Benefits Indicators (CBIs)		X		X	X	X	X
Community-based Resources (CBREs)		X	X		X		X

Topics covered	09/27/22	10/27/22	11/17/22	12/14/22	01/19/23	02/16/23	03/16/23
Resilience			X		X		X
Request for Proposal (RFP) – Potential CBRE RFP			X		X	X	X

L.2 Community input and feedback

An important component to PGE's community engagement is receiving input and feedback on our planning processes. PGE requested community feedback by leading Mural exercises within our Learning Labs so that we could go deeper into a specific topic. The Mural exercises usually consisted of a few questions for participants to answer for a specific amount of time about a particular subject. To allow more time to collect feedback, Mural exercises were open for additional contributions two weeks after each Community Learning Lab session. This way, people who couldn't actively participate in our Community Learning Labs were able to provide their input later. The following discusses the topics we worked on with our participants during the Learning Labs.

L.3 Mural board exercises

- **Community Benefits Indicators (CBIs)**

  As described in **Chapter 14, Community equity lens and engagement**, the HB 2021 Energy Advocates conducted extensive research and outreach among their constituents to collate a list of 15 Community Benefits Indicators. This list was shared as Attachment A of OPUC Order 22-390 for utilities to consider when developing their CBI approaches. PGE requested community input on CBIs as part of its community engagement strategy. Community input came over three Learning Lab sessions. Using a Mural voting exercise, stakeholders recommended which CBIs to prioritize for further research, such as identifying metrics for each of the prioritized CBIs. Additionally, Community Advocates utilized PGE's Mural board in one of their regular meetings to prioritize CBIs with their constituents, community members within the state (14 participants). The Community Advocates are a cohort of 12 community members that have been meeting with Energy

Advocates and organizers. For these meetings, PGE translated our Mural board into Spanish.

Figure 152 shows the four CBIs prioritized by participants of the Learning Labs, Energy Advocates and Community Advocates.

Figure 152. Community Benefits Indicators prioritized by community

Community Benefits Indicators	
Non-energy •Reduction in number of customers suffering from high energy burden •Meaningful bilateral engagement between utilities and tribes •Low income & vulnerable communities have access to an increasing number or renewable or non-emitting distributed generation resources	**Energy** Improve efficiency of housing stock in utility service territory, including low-income housing

- **Resilience: Metrics to analyze resilience and "Zone of Tolerance"**

  PGE's approach to resilience started by exploring available utility data, such as localized outage data (CEMI16 and CELID), to analyze the electric system's resilience. PGE also leveraged the equity index map created for DSP Part 2 as the source of data to identify vulnerable communities in its service area. Overlaying both data sets, utility data and equity data, enables us to identify locations in our service area where vulnerable communities and system outages occur and therefore might benefit from resilience investments.

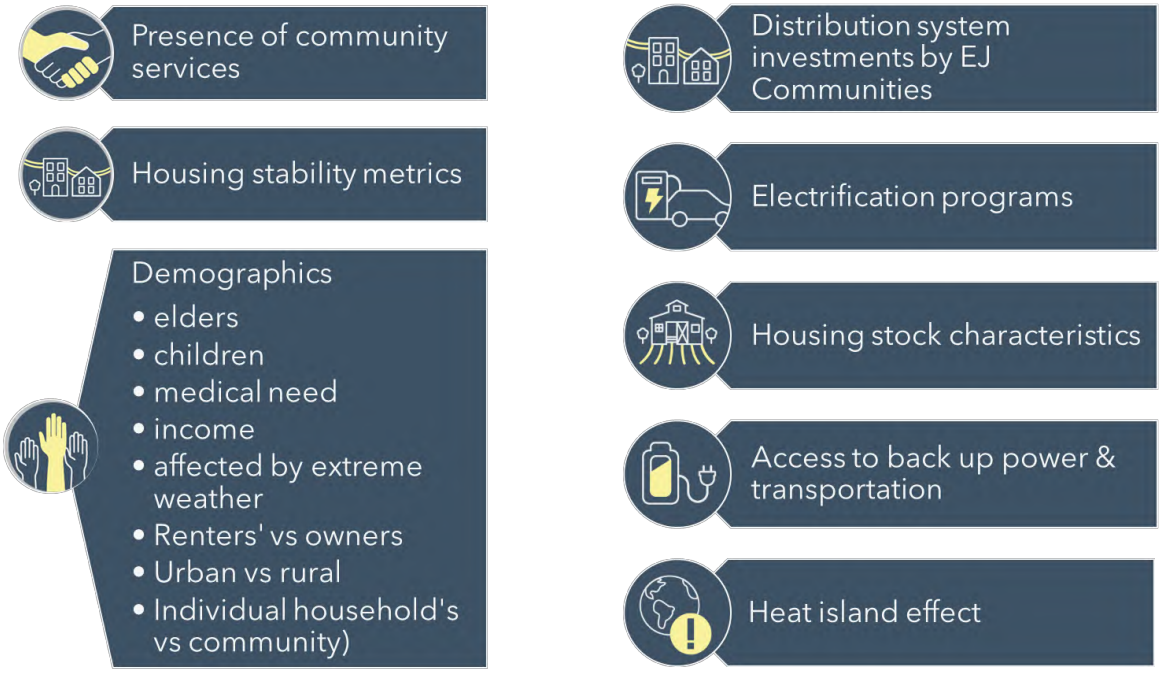
  Another resilience concept on which PGE requested input from community was metrics to understand and analyze "Zone of Tolerance." Zone of Tolerance definition: "Different capabilities of households and communities to endure the adverse impacts of service disruptions."

  PGE requested feedback via Mural on what other data sources PGE should explore to better understand and analyze resilience. Participants recommended that PGE explore eight data themes: community services, housing stability, demographics, distribution system investments, electrification, housing stock, access to back up power and transportation, and heat island effects (**Figure 153**).

  PGE will work on defining and locating vulnerable communities and assessing the Zone of Tolerance by exploring datasets in the eight themes community recommended. PGE will

continue using the heat island study[498] from Dr. Vivek Shandas[499] as a guide to locate the affected areas.

Figure 153. Data themes recommended by Learning Lab participants for PGE to explore in analyzing resilience & "Zone of Tolerance"



- **Community-based Renewable Energy (CBRE)**

  Early in the CEP Learning Lab series, PGE requested community input via Mural on examples of CBREs. Community Learning Lab participants described CBREs as microgrids, resilience hubs, and generation assets on public buildings (i.e., solar panels on school roofs).

- **CBRE – Microgrids**

  PGE took stakeholder input (i.e., defining CBREs as community microgrids) and further explored CBRE microgrids as a topic in a subsequent Learning Lab. CEP resilience guideline requested utilities to explore potential strategies to implement resilience projects. PGE started exploring a potential strategy to implement community resilience hubs through product development. Developing products at PGE is done with customer input to design products that would best serve customers. In the case of a potential

[498] Urban Heat Island Mitigation, available at: https://www.pdx.edu/sustainability/urban-heat-island-mitigation
[499] Professor Vivek Shandas, Nohad A. Toulan School of Urban Studies and Planning, Portland State University.

community microgrid, PGE product development sought feedback from stakeholders during a Learning Lab regarding the uses/benefits of the microgrid product:

- What would it be used to power, and
- Where would be the best siting for such a product in a community?

After level-setting, PGE requested input via Mural on how a community microgrid would best serve the community. Members shared that community microgrids would help limit resource loss (i.e., food and medications), run medical equipment, increase energy reliability, provide access to power during a major event outage, and create jobs when building one. PGE then asked members what critical facilities they would prefer powering during a major outage. Members identified hospitals, elder care homes, emergency shelters and community resource and service providers (i.e., grocery stores). Last, PGE asked what the preferred siting criteria would be for these microgrids. Members expressed the need for these community microgrid hubs to be sited in accessible areas to vulnerable communities and to take into consideration what a "safe space" means to different communities (i.e., undocumented community members might feel uncomfortable going to a building that belongs to an institution they fear).

Figure 154. Community feedback on a potential resilience product

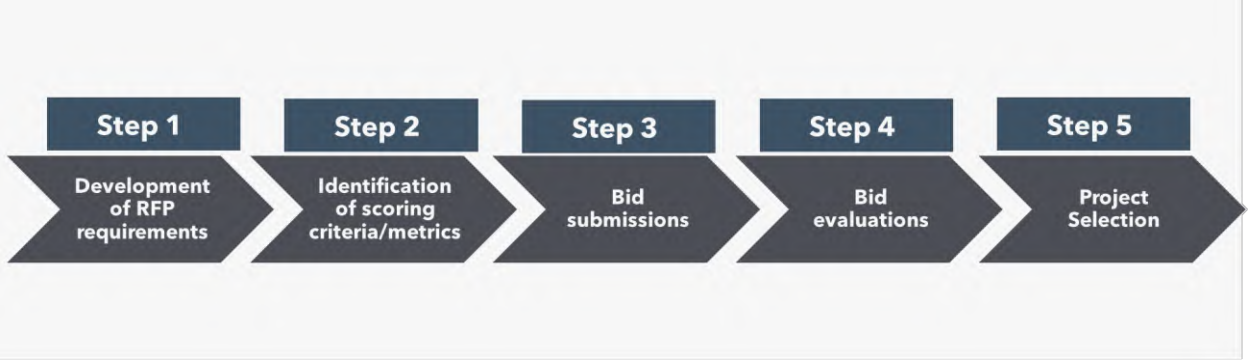
L.3.1 CBRE - Considerations

In a subsequent Learning Lab, PGE requested input on other considerations regarding CBREs. Participants expressed that, when designing or acquiring CBREs, PGE should give a higher priority to projects that solve for resilience and reduce GHG emissions. Participants also remarked that CBREs should not displace farm or forest land. Participants recommended that PGE explore stacking the value of resources when they support multiple objectives and policies and align with other agencies working on similar issues (i.e., Oregon Department of Energy (ODEO) Community Renewable Energy Grant program), understand which projects have been identified, and prioritize procurement of those projects. Two concerns participants raised were, 1) utilities will consider these CBREs too expensive, and will not consider the benefits these resources bring to community, and 2) utilities will favor companies with capital versus community focused enterprises.

L.3.2 CBRE - Acquisition paths

PGE used the participants' feedback on CBREs in designing an approach to acquire these energy resources. PGE is planning on working with Community Learning Lab participants to codevelop the scoring criteria (**Figure 155**) that are used to rank proposed CBRE projects and, ultimately, select the ones to move forward.

Figure 155. Community RFP evolution path



L.4 Community surveys

We used our community surveys to measure and track the effectiveness of our community engagement and our Learning Labs. From September 2022 through February 2023, we conducted six evaluation/feedback surveys to participants/attendees after each Learning Labs. This included hearing their perspectives on how their input should influence the plan.

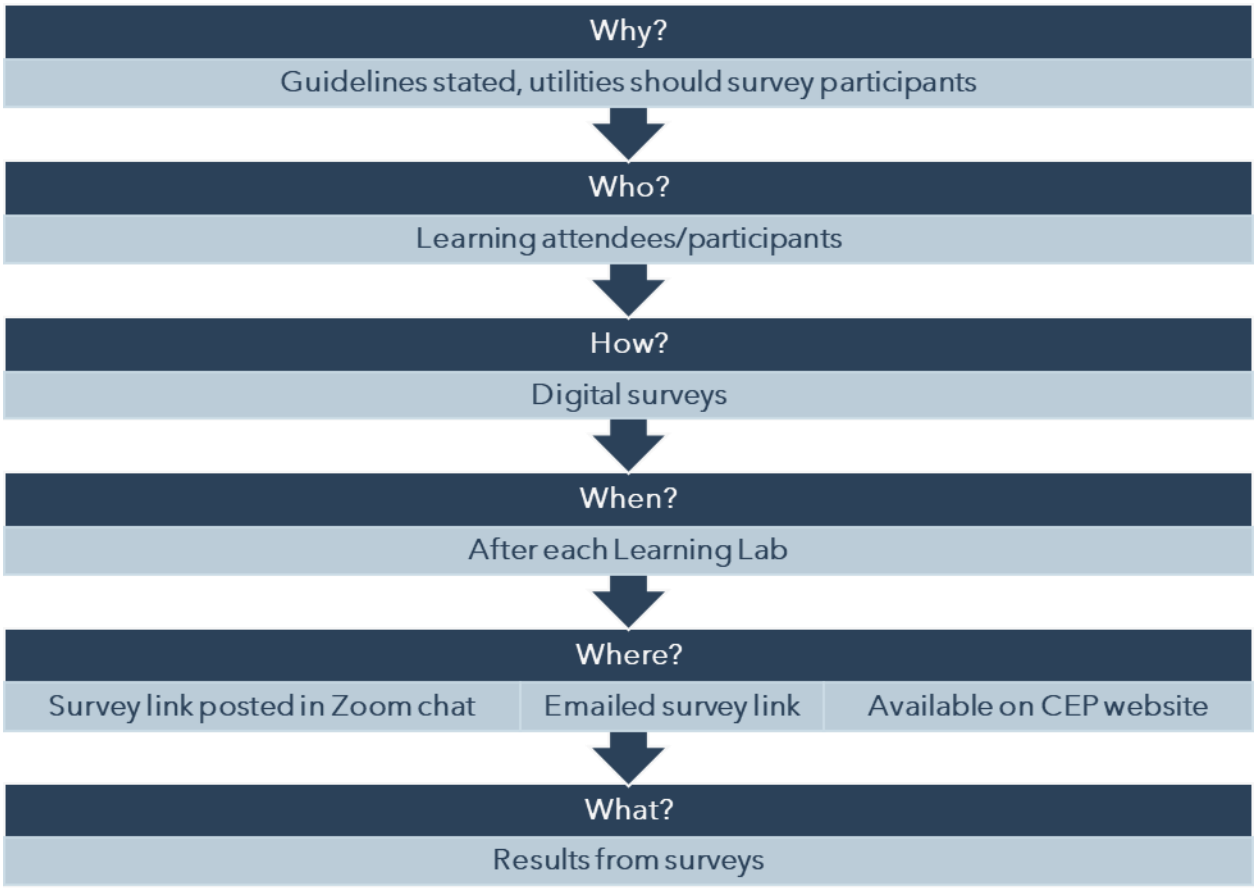
Surveys were left open several weeks after the Learning Lab so that participants had time to take the survey as their schedules allowed. Survey links were posted in the Learning Lab chat via Zoom, located on our CEP website, and sent via email notifications.

We designed digital surveys using a mix of quantitative and qualitative questions to assist in gathering information from participants. For consistency, and to easily quantify, we asked the repeated questions in our Learning Lab surveys 2-5 using a Likert-Scale (Strongly disagree, Disagree, Neutral, Agree and Strongly agree) to evaluate our presentations. Also, we asked open-ended qualitative questions where participants could provide written feedback, offer future Learning Lab content, and process improvement.

Survey respondents ranged from community-based organizations, and community service organizations to individual community members. Our survey results showed the highest response rate of 35 percent which was from our first Community Learning Lab – Kick-off Clean Energy Plan. As we administered more surveys, we saw a decline in respondents. Overall, we had a total of 10 respondents out of 64 attendees (16 percent) who took the survey. Although we didn't have high response rates, we still found the information collected to be meaningful and helpful.

We realized early that surveys could not be the only way to receive information as our response rates were lower than we hoped. Due to this, we met with a handful of attendees through informal interviews to receive input on suggestions for improvement and additional perspectives to our approach to community engagement strategy and the Learning Labs. From this experience we discovered we needed to have different modes of engagement. Surveys were a great tool to collect data, however getting participants to take a survey was challenging. Therefore, we decided to meet with attendees outside of the Learning Labs to obtain additional qualitative data. This informal setting allowed for a more relaxed environment for the person to share feedback and helped in building relationships with participants. **Figure 156** describes our process for conducting surveys.

Figure 156. Survey process map



PGE crafted 2 types of surveys to measure progress and incorporate feedback from participants. Our first survey was created to collect information on logistical preferences and potential future presentation topics. For logistical preferences we discovered was:

- 67 percent of respondents preferred to meet monthly versus quarterly.
- 83 percent of respondents it would be helpful to have meetings at the same day and time.
- 100 percent of attendees wanted Learning Labs to be recorded.

This feedback enabled us to set-up recurring meetings on the same day and time, so in January 2023 we scheduled our Learning Labs every third Thursday from 10:00am – 12:00pm.

Recommendations for potential future topics received from respondents were:

- "Different funding streams that can help build CBREs and other DSP projects."
- "How different dockets (IRP, DSP, CEP, WPP, TE) can be streamlined."
- "The follow-up to how CBIs could be part of large-scale resources RFP."
- "I was hoping the Learning Lab would be more like a tutorial to understand the IRP better. The IRP uses lots of acronyms and assumes many things that aren't made apparent even after listening for a year. I had hoped to be caught up on these matters. I would like to understand the unspoken pros and cons implied by graphs and discussions presented at IRP. For example, no one is explicit about the seriousness of the distribution/transmission problem. There isn't enough comparison of PGE demand and supply with the resources being considered in detail for me to get a sense of scale of the material. This could be improved at IRP (best) or addressed at the Learning Lab."
- "If leaving no one behind is one driving force for the work, it's going to be a huge task. Federal funds could do a lot but at some point, private funds will probably need to come into play. I like to get some idea of how much work can be accomplished in the short term and longer term to improve community resilience. How much funding is available through ETO and other sources? How much can we expect will get done in the next 5 years?"

From these recommendations from community, we incorporated topics for discussion, such as: CBREs, CBIs, DSP projects, conversations about other dockets, IRP Roundtable updates, created an acronym key to eliminate barriers to understanding materials, RFP process and spoke about large-scale resources.

Our approach to our second type of survey was used to measure and evaluate content presented in our Learning Labs. The method used was asking participants four questions (see

Table 136) using a Likert-Scale (1 strongly disagree, 2 disagree, 3 neutral, 4 agree and 5 strongly agree) and this process was repeated for Learning Labs 2-5 surveys to maintain consistency in measuring our progress. What we learned was on an average respondents 'Agreed', our meeting objectives of the presentation were clearly stated and met, the presentation was well-organized and easy to follow, the information presented was relevant and useful and the content presented increased my knowledge of topic(s). We were pleased with the results, and found it demonstrated we were delivering content in a way that was understandable. We do recognize we had a small sample size, but we believe our Learning Labs were in impactful and did good job incorporating attendees' feedback.

Table 136. Repeated survey questions to assess value delivered to attendees

Question	Agreed
The objectives of the presentation were clearly stated and met.	3.8
The presentation was well-organized and easy to follow.	4.3
The information presented was relevant and useful.	4.0
The content presented increased my knowledge of topic(s).	3.5

The qualitative data that was collected, via our survey, provided us greater insight into how the participant was feeling and gave them an opportunity to openly and anonymously express feedback on our Learning Labs (see **Table 138**). Highlights from what we learned from attendees when we asked for Additional comments/feedback you would like to share, including recommendations for improvement. The following are the responses from Learning Lab sessions 1-5:

- "I think it is important to have a sense of what these meetings are leading to. Process is really important, and iteration is important too, but when we are dedicating hours to a process it is crucial for us to see tangible outcomes. Having a sense of what those can be early on is helpful."
- "The presentation was good. The make-up of the room was low on the CBO space (I think at one point I counted 10 people who were not IOU or not PUC, and one CBO partner). Not sure how you can go about addressing that as I know you are trying to make this room accessible to people in the CBO space. Will keep thinking and offer any suggestions that I come up with."
- "It was a really good meeting. The content was good. All the presentations felt good to me. Will encourage folks to watch the video if they could not make it."

- "In general, it would have helped for audience members to have materials before the presentation so that they could review it and be ready to learn. The presenter had the most information dense slides in the deck and although he obviously knows his subject matter, he has to understand his audience doesn't have nearly as much insight as he does. Slowing down enough to allow listeners to visually bring their eyes to the information being highlighted would help. I saw the moving his cursor, but he did not linger over the info long enough to make sure listeners could catch up with him."

We read everyone's feedback and acknowledged the areas where could make improvements. One respondent called out there were a large number of investor-owned utilities (IOUs) in the meeting, so we internally addressed this and capped the number of PGE employees who could attend. Also, we heard from another respondent that they wanted to us to share "tangible outcomes", so at our fifth Learning Lab we provided a progress report and updates of where we were at in the CEP process. This meeting was well received by attendees, and it taught us to have progress reports and updates every few months. We recognized the importance and value of collecting qualitative data and used this inform our future Learning Lab content and process improvement.

In conclusion, the surveys provided helpful feedback and input from our Learning Lab participants. In addition to measuring and evaluating our progress throughout CEP process. Again, we recognize that surveys were an efficient tool to measure outcomes and collect data, however low response rates were a challenge and could be found as ineffective. Overall, we thought our level of engagement was good and will continue to develop and learn from this experience.

Table 137. Quantitative survey responses

Learning Lab Date	Lab #	# of attendees	Total # of responses	# of responses per question	Percent	Question	Response
9/21/2022	1	17	6			What cadence would you find useful (monthly, quarterly, semi-annually, annually, or other)?	
9/21/2022	1	17	6	4	67%		Monthly
9/21/2022	1	17	6	2	33%		Quarterly
9/21/2022	1	17	6	5	83%	Would it be helpful to have meetings the same day and time?	Yes
9/21/2022	1	17	6	1	17%		Other
9/21/2022	1	17	6	6	100%	Do you want meetings to be recorded?	Yes
9/21/2022	1	17				How many Learning Labs (0-6) would you mostly likely attend the before March 2023?	
9/21/2022	1	17	6	4	66%		6
9/21/2022	1	17	6	1	17%		5
9/21/2022	1	17	6	1	17%		4
TOTAL RESPONSE RATE	**1**	**17**	**6**		**35%**		
10/27/2022	2	13	1	1	100%	The objectives of the presentation were clearly stated and met.	Agree

Learning Lab Date	Lab #	# of attendees	Total # of responses	# of responses per question	Percent	Question	Response
10/27/2022	2	13	1	1	100%	The presentation was well-organized and easy to follow.	Strongly Agree
10/27/2022	2	13	1	1	100%	The information presented was relevant and useful.	Strongly Agree
10/27/2022	2	13	1	1	100%	The content presented increased my knowledge of: Grid Needs, Non-Wires Solutions, Community Benefits Indicators and Community-Based Renewable Energy.	Agree
TOTAL RESPONSE RATE	**2**	**13**	**1**		**8%**		

Learning Lab Date	Lab #	# of attendees	Total # of responses	# of responses per question	Percent	Question	Response
11/16/2022	3	20		1	50%	The objectives of the presentation were clearly stated and met.	Strongly Agree
11/16/2022	3	20		1	50%	The objectives of the presentation were clearly stated and met.	Neither agree nor disagree
11/16/2022	3	20		1	50%	The presentation was well-organized and easy to follow.	Strongly Agree
11/16/2022	3	20		1	50%	The presentation was well-organized and easy to follow.	Agree
11/16/2022	3	20		1	50%	The information presented was relevant and useful.	Strongly Agree
11/16/2022	3	20		1	50%	The information presented was relevant and useful.	Disagree
11/16/2022	3	20				The content presented increased my knowledge of the following:	
11/16/2022	3	20	2	1	50%	Resilience	Strongly Agree
11/16/2022	3	20	2	1	50%	Request For Proposal 101	Strongly Agree

Learning Lab Date	Lab #	# of attendees	Total # of responses	# of responses per question	Percent	Question	Response
11/16/2022	3	20	2	1	50%	Community Benefits Indicators	Strongly Agree
11/16/2022	3	20	2	1	50%	Community-Based Renewable Energy	Strongly Agree
11/16/2022	3	20	2	1	50%	Resilience	Neither agree nor disagree
11/16/2022	3	20	2	1	50%	Request For Proposal 101	Neither agree nor disagree
11/16/2022	3	20	2	1	50%	Community Benefits Indicators	Neither agree nor disagree
11/16/2022	3	20	2	1	50%	Community-Based Renewable Energy	Neither agree nor disagree
TOTAL RESPONSE RATE		**20**	**2**		**10%**		

Learning Lab Date	Lab #	# of attendees	Total # of responses	# of responses per question	Percent	Question	Response
12/14/2022	4	7	1	1	100%	The objectives of the presentation were clearly stated and met.	Neither agree nor disagree
12/14/2022	4	7	1	1	100%	The presentation was well-organized and easy to follow.	Neither agree nor disagree
12/14/2022	4	7	1	1	100%	The information presented was relevant and useful.	Agree
12/14/2022		7				The content presented increased my knowledge of:	
12/14/2022		7	1	1	100%	Community Benefits Indicators (iCBIs, rCBIs & pCBIs) in IRP modeling	Agree
12/14/2022	4	7	1	1	100%	Resilience Product Development	Agree
TOTAL RESPONSE RATE		**7**	**1**		**14%**		

Learning Lab Date	Lab #	# of attendees	Total # of responses	# of responses per question	Percent	Question	Response
1/19/2023	5	7	0	0	0%	The objectives of the presentation were clearly stated and met.	
1/19/2023	5	7	0	0	0%	The presentation was well-organized and easy to follow.	
1/19/2023	5	7	0	0	0%	The information presented was relevant and useful.	
1/19/2023	5	7	0	0	0%	I appreciated the updates and content presented about the following:	
1/19/2023	5	7	0	0	0%	Community Engagement	
1/19/2023	5	7	0	0	0%	Resilience Product	
1/19/2023	5	7	0	0	0%	Potential CBRE Acquisition Paths	
1/19/2023	5	7	0	0	0%	Community Benefits Indicators	
1/19/2023	5	7	0	0	0%	Community Benefits and Impacts Advisory Group	

Learning Lab Date	Lab #	# of attendees	Total # of responses	# of responses per question	Percent	Question	Response
1/19/2023	5	7	0	0	0%	IRP Roundtable	
1/19/2023	5	7	0	0	0%	Distribution System Plan Generation Evaluation Map	
TOTAL RESPONSE REATE		**7**	**0**		**0%**		

Table 138. Qualitative survey results

Lab #	Question	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback
1	What topics do you want covered in our CEP learning labs?	CBIs, ways to streamline all three processes, how PGE will define resiliency.	Exploring in more detail how the three processes interact (IRP, DSP, CEP), community benefits indicators, exploring how justice issues can be addressed in IRPs (beyond CBREs), community resilience.	Multiple and varied community insights from the range of customers PGE serves, and reflection from PGE on how those insights are used or not.	Emissions reductions, upgrades to services in EJ communities, maximizing grid tech upgrades, reducing costs where possible	Understanding PGEs existing generation resources (purchases and facilities PGE owns) and which resources power residential customers electricity.	Utilities 101, what is OPUC, what is DSP, what does Energy Trust of Oregon do, benefits of heat pumps, funding opportunities.

Lab #	Question	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback
1	Who is missing from this space (recommendations for whom we ought to invite)?			There were quite a few utility representatives and few community members.	I'm not sure the EJ representatives have enough presence from what I have observed in OPUC meetings.		

Lab #	Question	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback
1	What are your recommendations for holding multiple meetings (i.e., IRP, DSP, and CEP)?	Recording them and sharing out recordings and slides so that people can watch when they have time. Sharing emails beforehand about the meeting topics so people can attend the pieces that they are most interested in (if they can't attend all of each meeting).		Meetings can be separate and held as needed; but each one should start as this one did - overview of the planning at PGE, where this particular meeting fits in there, where to go if you want to catch up on the whole or other pieces.	I think for me an integrated approach would be best.	Consolidate as much as possible.	

Lab #	Question	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback
1	How can we make information more accessible?	Posting recordings and slides in an easy to access place or sharing out the recording and slides to the email group.		Broader distribution of meeting invitations; proactive outreach to get people to the table.	Because I'm not sure I know how to explore your existing information adequately, I would appreciate an overview.	Email resources and agenda prior to calls and make recordings available shortly after.	Materials translated in Spanish, also maybe a Spanish interpreter in meetings if needed
1	What recommendations can you provide for collaboration with our tribal communities?			Remain in a learning mode far longer than you are comfortable with; when you think it's time to move to the next stage, hold and go back into learning mode. Truly commit to a lasting relationship.	I have no expertise here.	Reach out to Tribes directly.	Start with one-on-one interviews - collaborate with Indigenous community-based organizations.

Lab #	Question	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback
1	Any additional feedback you would like to share?		I think it is important to have a sense of what these meetings are leading to. Process is really important, and iteration is important too, but when we are dedicating hours to a process it is crucial for us to see tangible outcomes. Having a sense of what those can be early on is helpful.				Thanks for all the work you are doing, this is very important!

Lab #	Question	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback
2	What topics would you like to be considered in future Learning Labs?	-Different funding streams that can help build CBREs and other DSP projects. -How different dockets (IRP, DSP, CEP, WPP, TE) can be streamlined.					

Lab #	Question	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback
3	What topics would you like to be considered in future Learning Labs?	The follow up to how CBIs could be part of large-scale resources RFP.	I was hoping the Learning Lab would be more like a tutorial to understand the IRP better. The IRP uses lots of acronyms and assumes many things that aren't made apparent even after listening for a year. I had hoped to be caught up on these matters. I would like to understand the unspoken pros and cons implied by graphs and discussions presented at	The presentation was good. The make-up of the room was low on the CBO space (I think at one point I counted 10 people who were not IOU or not PUC, and one CBO partner). Not sure how you can go about addressing that as I know you are trying to make this room accessible to people in the CBO space. Will keep thinking and offer any suggestions			

Lab #	Question	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback
			IRP. For example, no one is explicit about the seriousness of the distribution/ transmission problem. There isn't enough comparison of PGE demand and supply with the resources being considered in detail for me to get a sense of scale of the material. This could be improved at IRP (best) or addressed at the Learning Lab.	that I come up with. It was a really good meeting. The content was good. All the presentations felt good to me. Will encourage folks to watch the video if they could not make it.			

Lab #	Question	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback
3	Additional comments/feedback you would like to share, including recommendations for improvement.	The presentation was good. The make-up of the room was low on the CBO space (I think at one point I counted 10 people who were not IOU or not PUC, and one CBO partner). Not sure how you can go about addressing that as I know you are trying to make this room accessible to people in the CBO space. Will keep thinking and offer any suggestions					

Lab #	Question	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback
		that I come up with. It was a really good meeting. The content was good. All the presentations felt good to me. Will encourage folks to watch the video if they could not make it.					
4	What topics would you like to be considered in future Learning Labs?	If leaving no one behind is one driving force for the work, it's going to be a huge task. Federal funds could do a lot but at some point, private funds will probably					

Lab #	Question	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback
		need to come into play. I like to get some idea of how much work can be accomplished in the short term and longer term to improve community resilience. How much funding is available through ETO and other sources? How much can we expect will get done in the next 5 years?					

Lab #	Question	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback
4	Additional comments/feedback you would like to share, including recommendations for improvement.	In general, it would have helped for audience members to have materials before the presentation so that they could review it and be ready to learn. Mr. Shah had the most information dense slides in the deck and although he obviously knows his subject matter, he has to understand his audience doesn't have nearly as much insight as he					

Lab #	Question	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback
		does. Slowing down enough to allow listeners to visually bring their eyes to the information being highlighted would help. I saw Mr. Shah moving his cursor, but he did not linger over the info long enough to make sure listeners could catch up with him.					
5	No respondents						

Appendix M. Supply-side options

This appendix provides information summarizing the operational and cost attributes of various power generation and storage technologies. The technologies considered include onshore and offshore wind, solar photovoltaic, battery and pumped hydroelectric energy storage, hydrogen production and storage, geothermal, biomass, nuclear powered generation, and various natural gas-fueled resources including a combined-cycle combustion turbine with carbon sequestration.

M.1 Sources of information

M.1.1 Resource costs and operating parameters

The National Renewable Energy Laboratory produces the Annual Technology Baseline (NREL ATB) to "develop and document transparent, normalized technology cost and performance assumptions" for typical generating resources in the United States. The Energy Information Administration (EIA) commissioned Sargent & Lundy to "evaluate the overnight capital cost and performance characteristics for 25 electric generator types" to reflect these generators in the Annual Energy Outlook 2020 (EIA AEO).[500] Resource capital and operating expenditures, as well as operating parameters, are sourced from the ATB and AEO unless otherwise noted (**Table 139** and **Table 140**). Where information needed for PGE's models is not provided in the ATB or AEO, PGE relies on information from other publicly available sources, including supply-side options studies prepared in support of past IRPs. Historical inflation rates were applied to escalate from the EIA and NREL study values.

Note that in tables containing numerical values, the totals may not add due to rounding.

NREL defines capital expenditures as generally including costs in the following categories:[501]

[500] EIA AEO 2020. "Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies." Prepared by Sargent & Lundy. Available at: https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf

[501] NREL 2021 Electricity ATB. Available at: https://atb.nrel.gov/electricity/2021/definitions

Table 139. Capital expenditure details

Capital expenditure components	Description
Balance of system/balance of plant	All other major plant components within the facility fence line are necessary to deliver electricity to the bulk power system.
Electrical infrastructure and interconnection (electrical interconnection, electronic, electrical infrastructure, electrical)	• Internal and control connections • Onsite electrical equipment (e.g., switchyard) • Power electronics • Transmission substation upgrades
Generation equipment and infrastructure (civil works, generation equipment, other equipment, support structure)	• Plant construction • Power plant equipment
Installation and indirect	• Distributable labor and materials • Engineering • Start-up and commissioning
Owners' costs	• Development costs • Environmental studies and permitting • Insurance • Legal fees • Preliminary feasibility and engineering studies • Property taxes during construction
Site costs	• Access roads • Buildings for operation and maintenance • Fencing • Land acquisition • Site preparation • Transformers • Underground utilities

NREL defines operational expenditures as generally including costs in the following categories:[502]

Table 140. Operational expenditure details

Operational expenditure components	Description
Fixed costs	• Administrative fees • Administrative labor • Insurance • Land lease payments • Legal fees • Operating labor • Other • Property taxes • Site security • Taxes
Fixed costs components	Project management
Maintenance costs	• General maintenance • Scheduled maintenance over technical life • Unscheduled maintenance over technical life
Variable cost components	• Consumables (e.g., water, chemicals, catalysts, etc.) • Waste disposal (e.g., ash, slag, process wastes, process byproducts that are not otherwise sold, etc.)
Maintenance components	Transformers
Replacement costs	Annualized present value of large component replacement over technical life

[502] *Id.*

M.2 Renewable resources

M.2.1 Onshore wind

Technology description

Wind turbine generators convert kinetic wind energy into electrical power. The horizontal-axis three-bladed design is the most ubiquitous type of wind turbine used for electric power generation. Lift is generated when wind flows around the turbine blades, resulting in rotation. The blades are connected to a central hub and drivetrain that turns a generator inside the nacelle, which is the housing positioned atop the wind turbine tower.

Commercial status

Installed wind capacity has grown by more than 50 percent in the United States since 2017. At the end of 2021, wind generating capacity in the country totaled nearly 136 GW.[503] Key aspects of wind turbine generator designs continue to grow as well. The average rated capacity of new turbines in 2021 was 3.0 MW, 9 percent more than the year prior. Likewise, the blade rotor diameter of new turbine installations grew 2 percent to 127.5 meters and hub heights rose to nearly 94 meters or 4 percent higher than the prior year's average.[504]

Operational characteristics

Three PNW sites, and one Wyoming location, are modeled with identical turbine specifications and layouts, shown in **Table 141**:

Table 141. Summary of Oregon onshore wind operational characteristics 2026 COD

Site	Lat.	Long.	IRP CF%
Oregon Gorge	45.65	-120.63	44.4%
Central Montana	46.35	-110.34	42.3%
Southeast Washington	46.41	-117.84	42.0%
Casper Wyoming	43.04	-105.56	44.1%

[503] Lawrence Berkeley National Laboratory. "Land-based Wind Market Report: 2022 Edition," available at: https://emp.lbl.gov/publications/land-based-wind-market-report-2022
[504] *Id.*

3.5 MW turbines are modeled in System Advisor Model (SAM) using eight years of weather data, as mentioned previously. The Hub height is 105 meters, and rotor diameter is 136 meters. These parameters are consistent with those specified for a NW wind resource in PGE's most recent IRP. Maintaining a consistent resource configuration at the three sites focuses any analysis on wind resource variations rather than attempting to optimize each site's design. It is expected that developers in the marketplace will use their expertise to design an optimal solar PV resource for any specific location. Each site employs 87 turbines to provide approximately 300 MW of generating capacity. The default layout in SAM arranges the turbines in three rows of 29 turbines with eight-rotor diameter spacing. The "Simple Wake Model" estimates the interactive effects on downwind turbines. According to NREL, this model "uses a thrust coefficient to calculate the wind speed deficit at each turbine due to wake effects of the upwind turbines."[505]

An hourly generation profile is simulated for each year of weather data for each site listed in the previous table. These hourly generation profiles are produced using SAM. The profiles are used as inputs to Sequoia. The hourly shape for the representative year is used as input to Aurora for energy modeling.

Operational expenditures

Operational expenditures for the representative onshore wind resource are derived from the EIA AEO 2020 study, shown in **Table 142**. The general categories of costs included in operational expenditures are listed earlier.

Table 142. Summary of Oregon onshore wind operational expenditures

Operational expenditures, onshore wind				
2019$	**Oregon Gorge**	**Southeast Washington**	**Central Montana**	**Casper Wyoming**
Fixed O&M ($/kW-year)	$26.34	$26.34	$26.34	$26.34
Less: Land Lease	$2.80	$2.80	$2.80	$2.80
Fixed O&M Ex-Land Lease	$23.54	$23.54	$23.54	$23.54

[505] SAM Version 2021.12.02 Help System. NREL. https://sam.nrel.gov/images/web_page_files/sam-help-2021-12-02.pdf

Operational expenditures, onshore wind				
Variable O&M ($/MWh)	$0	$0	$0	$0
Variable Land Lease ($/MWh)	$1.70	$1.70	$1.70	$1.70

Capital expenditures

Cost information is derived from the EIA AEO 2020 study. The general categories of costs included in capital expenditures are listed earlier. The EIA transmission line costs are removed, and PGE estimated values are used in the revenue requirements modeling process. A locational cost adjustment is applied based on the EIA study's resource location and the adjustment factors. The factors from the EIA study correspond to an average of Portland, Spokane, and Boise factors for the Oregon Gorge resource, an average of Spokane and Boise factors for the Southeast Washington resource, and Great Falls for the Montana resource (**Table 143**). Capital expenditures for the Casper, Wyoming, resource mirror the Central Montana location.

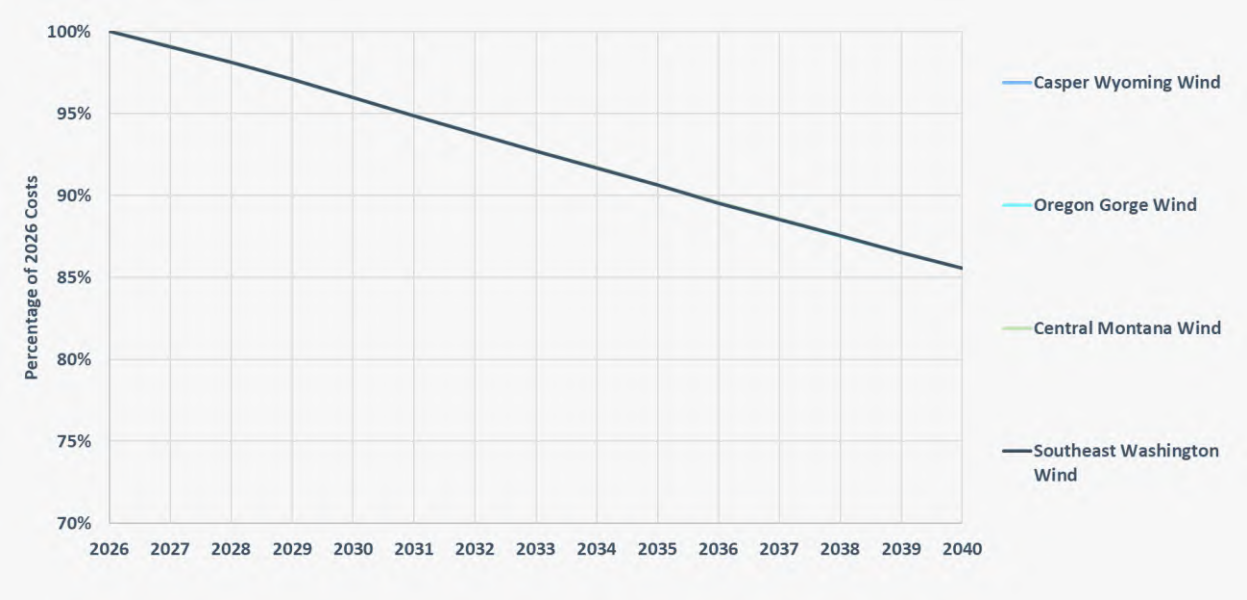
Table 143. Summary of Oregon onshore wind capital expenditures

Capital expenditures, onshore wind				
2019 $/kW	Oregon Gorge	Southeast Washington	Central Montana	Casper Wyoming
Overnight capital	$1,265	$1,265	$1,265	$1,265
Less: Transmission Line Cost	$6	$6	$6	$6
Overnight EPC Capital Cost -Ex Interconnect Cost	$1,259	$1,259	$1,259	$1,259
Location Adjustment	1.02	1.02	0.99	0.99
Location-adjusted Overnight Capital Cost	$1,288	$1,278	$1,246	$1,246

Forward capital cost curve

EIA onshore resources share a common forward capital cost trajectory across the various sites. The EIA AEO 2020 projection of future capital costs for the Reference Case scenario are presented in **Figure 157**.

Figure 157. Onshore wind capital cost trajectory



M.2.2 Offshore wind

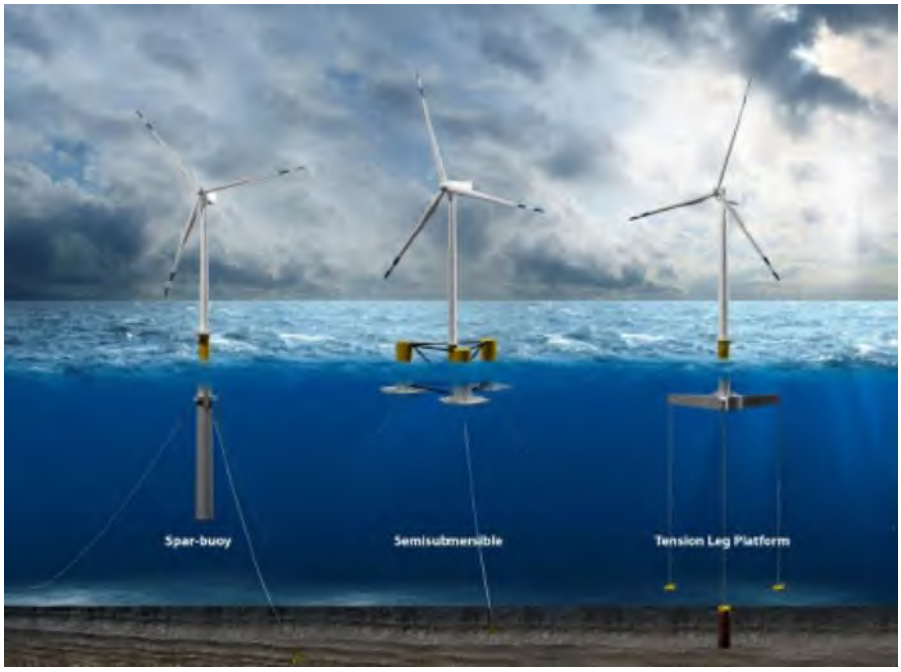
Technology description

Electricity generation from offshore wind is conceptually similar to that of onshore wind. The primary difference is that the wind plant is in offshore waters allowing access to a potentially diverse and more energetic wind resource. The offshore wind technology is generally described by the structure that suspends the turbine: "fixed-bottom" resources are those with a tower attached directly to the seabed; "floating" installations do not anchor the tower directly to the ground, but rather employ a structure that floats in the water and is anchored to the seabed (**Figure 158**). The application of fixed bottom vs. floating technology is generally dictated by the depth of the water, with water in excess of 60 meters typically requiring the use of a floating structure. According to NREL research, water depths are greater than 60 meters in 97 percent of the water on the Outer Continental Shelf (OCS – administered by the federal government) off the Oregon coast, dictating the use of a floating technology as opposed to fixed-bottom.

The structure further defines the technology: spar-buoy, semi-submersible, tension leg platform.

Each design offers certain advantages and disadvantages relative to the others. For example, the semi-submersible design has a shallower draft (the distance the structure occupies under the water surface) than the spar-buoy type, requiring less water depth for assembly. Companies are Innovating structure designs to optimize costs and performance. According to NREL, the semi-submersible structure is dominant in the conditions expected for Oregon offshore wind development and is the basis for cost estimates.

Figure 158. Floating offshore wind platforms



The assumption for a project online in 2032 makes use of semi-submersible platforms employing turbines rated at 15 MW with 248-meter rotor diameters at hub heights of 150 meters. These specifications are equivalent to those proposed by NREL for the 2032 reference technology. Turbine power curve data are also consistent with those used by NREL, as updated for 2021.[506]

[506] Musial, Walter, Patrick Duffy, Donna Heimiller, and Philipp Beiter. 2021. Updated Oregon Floating Offshore Wind Cost Modeling. Available at: nrel.gov/docs/fy22osti/80908.pdf.

Commercial status

European deployments of offshore wind vastly outpace those of the United States. According to WindEurope, an industry advocacy group, total offshore wind capacity in Europe totaled more than 28 GW at 2021year-end. This capacity is expected to almost double in the period 2022–2026. More than 3 GW was added in 2021 alone.

The Biden Administration has stated a goal of 30 GW of offshore wind by 2030. The state of California has established a goal of 2-5 GW of offshore wind capacity by 2030 and 25 GW by 2045.[507] State and federal goals for offshore wind development In the United States, offshore wind development in federal waters is overseen by the Bureau of Ocean Energy Management (BOEM). The areas under BOEM's responsibility include the submerged lands on the OCS, which begins approximately three nautical miles offshore and extends to 200 nautical miles marking the exclusive economic zone boundary. BOEM controls the process for issuing leases and approving offshore wind projects on the OCS. The leasing process includes stakeholder engagement and numerous opportunities for review and approval. This process may extend many years from the lease initiation to the approval of a construction and operations plan preceding construction. BOEM plans to review 16 offshore wind projects, more than 22 GW, by 2025.

As of mid-2021, two offshore wind projects were operating in waters off the east coast of the US: Block Island Wind Farm (approximately 30 MW off the coast of Rhode Island) and the Coastal Virginia Offshore Wind pilot project (12 MW off the Virginia coast). Additionally, the 800 MW Vineyard Wind project off the Massachusetts coast is fully permitted and expected to be operational in 2024, while the 130 MW South Fork project off the coast of Rhode Island was approved in 2022 and may reach COD in 2023.

The 2022 New York Bright auction for offshore wind leases saw six developers win leases on six areas representing more than 488,000 acres. The winning bids totaled $4.37 billion, or an average of nearly $9,000 per acre.

Two BOEM wind energy areas are off the California coast (Morro Bay and Humboldt). The results of the lease sale for these sites were released December 7, 2022.[508] Five leases were sold through the auction. The sites comprise more than 370,000 acres with an average price of approximately $2,000 per acre. BOEM reports that development of these lease areas could potentially support 4.6 GW of generating capacity.

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[507] California Energy Commission. Offshore Wind Energy Development off the California Coast. August 2022. https://www.energy.ca.gov/filebrowser/download/4361#page=63&zoom=100,0,0

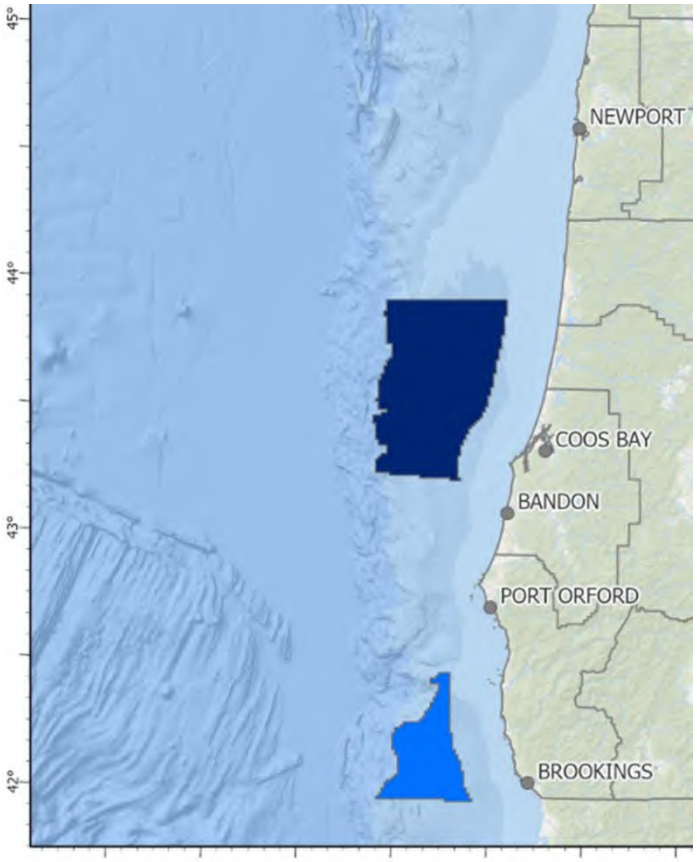
[508] US Department of the Interior. Biden-Harris Administration Announces Winners of California Offshore Wind Energy Auction. https://doi.gov/pressreleases/biden-harris-administration-announces-winners-california-offshore-wind-energy-auction

Oregon offshore developments

In HB 3375, Oregon's Legislative Assembly identifies several potential benefits and roles that offshore wind could bring to the utility/electricity sector and regional economy. The legislation requires the Oregon Department of Energy to explore the "benefits and challenges of integrating up to three gigawatts of floating offshore wind energy into Oregon's electric grid by 2030."

On April 27, 2022, the BOEM issued a Call for Information and Nominations regarding the potential for wind energy leases in federal waters off the south-central and southern Oregon coast (**Figure 159**). The two areas identified (Call Areas) comprise approximately 1,800 square miles. The Coos Bay Call Area represents over 1,300 square miles with water depths ranging from 400 to 700 feet. The southern Brookings Call Area is more than 400 square miles in depths of 400 to 1,100 feet.

Figure 159. Coos Bay and Brookings call areas[509]



The areas potentially leased for commercial development will be a subset of the Call Areas. The initial BOEM leases could result in up to 3 GW of offshore wind capacity, per published statements. The total potential offshore wind capacity in the Call Areas is roughly 14 GW according to BOEM's assessment (assumes 3 MW / square kilometer).

NREL analysis finds the potential for up to 2.6 GW of wind nameplate capacity, or nearly 2.2 GW, at the assumed points of interconnect (POIs) along the Oregon coast. The findings are summarized in **Table 144** (note that the difference between the "Max Capacity" and "Max Injected" values is explained by assumed losses between the plant and POI). These values arise from NREL's attempt to determine the "maximum possible penetration of offshore wind without trans-coastal transmission infrastructure upgrades." Per NREL, the analytical process is as follows:

[509]Coos Bay and Brookings call areas, available at: https://www.boem.gov/sites/default/files/images/or_callareas_april2022.jpg

> *"We started by scaling the maximum power output of offshore wind at each of the five points of interconnection to match the summer trans-coastal line limit for the associated evacuation line. The summer limits were verified in consultation with BPA; however, there is uncertainty regarding the exact limits on these lines. Then, we ran the full-year model and checked for congestion of the trans-coastal lines. If a particular line did not exhibit congestion during the entire year, we increased the capacity of its associated offshore wind generation by the available capacity in its highest use hour (i.e., the maximum flow subtracted from the line limit). If a line exhibited congestion, we first checked that the congestion occurred simultaneously with the curtailment of its associated offshore wind generation. We then reduced the offshore generation capacity to eliminate the congestion. We repeated this process several times until the trans-coastal transmission was fully utilized with minimal congestion and with no study site experiencing more than 1 percent annual curtailment."*

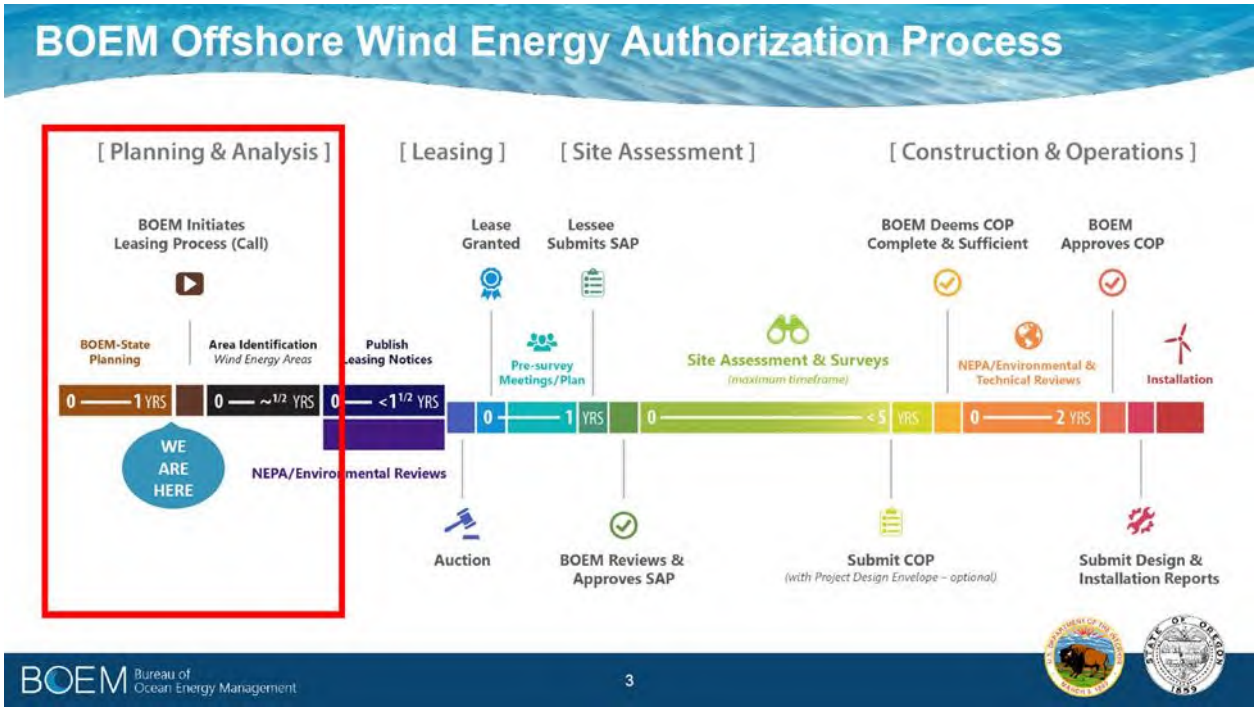
Table 144. NREL Oregon offshore wind interconnection potential

Offshore Wind Point of Interconnection	Max Capacity (MW)	Max Injected Power (MW)
1 – Clatsop	361	301
2 – Tillamook	553	461
3 -Toledo	156	130
4 - Wendson	613	512
5 - Fairview	941	7852
Total	2625	2189

The NREL authors note, "Detailed power flow analysis is needed to refine the distribution of offshore wind, the total offshore wind capacity, and identify small upgrades to the trans-coastal system to enable or increase the 2.6 GW finding."

Lengthy lead time gave the BOEM lease auction process and regulatory requirements (Site Assessment Plan – SAP, Construction and Operations Plan – COP) preceding the construction phase. The following timeline from BOEM's Oregon offshore wind process is still relatively near the beginning (**Figure 160**). Current expectations are a COD for the first Oregon offshore wind project in 2032.

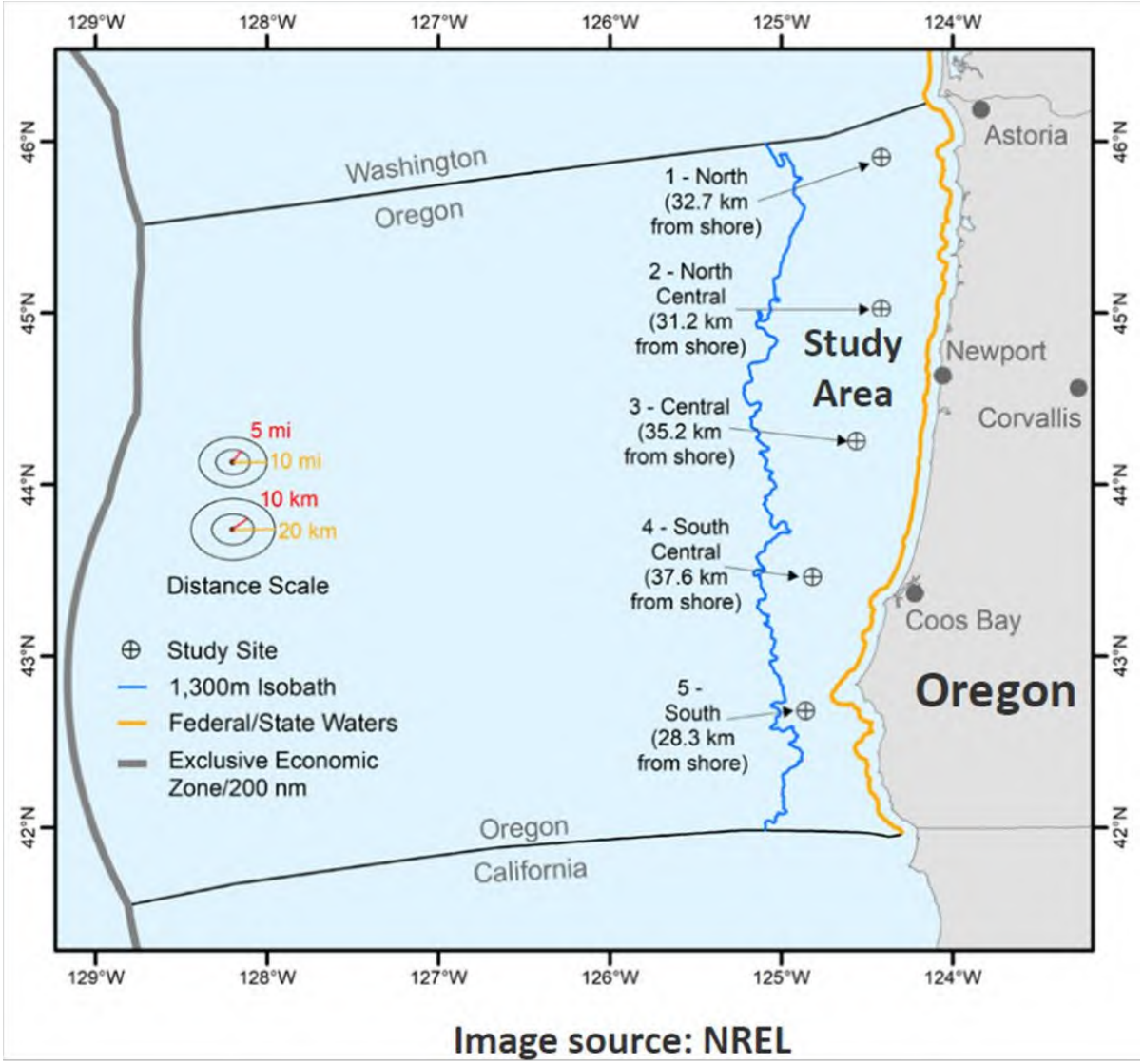
Figure 160. BOEM offshore wind development process



Operational characteristics

Figure 161 shows NREL research which presents five potential sites for Oregon offshore wind:

Figure 161. NREL Oregon offshore sites



Study Site "4 – South Central" in the NREL graphic is approximately equivalent to a location within the Coos Bay Call Area, while Study Site "5 – South" aligns with Brookings Call Area.

PGE focuses on the southernmost site to model an offshore wind resource. This site produces the highest capacity factors based on analysis of the historical weather data.

PGE's analysis of the wind resource utilizes an NREL dataset covering the 20 years 2000 through 2019 ("OR-WA20" dataset).

The generic offshore wind resource in the IRP is modeled as a semi-submersible platform 15 MW turbine with a 248-meter rotor diameter at a hub height of 150 meters (**Table 145**). These specifications are equivalent to those proposed by NREL for the 2032 reference technology. Sixty-four turbines are used to provide approximately 960 MW of generating capacity. The turbine arrangement is based on a seven-rotor diameter spacing per NREL. The default layout in SAM arranges the turbines in eight rows of eight turbines. As with the onshore wind analysis, the "Simple Wake Model" estimates the interactive effects on downwind turbines. PGE's energy modeling analysis uses the NREL published power curve for a 15 MW turbine, including revisions to the cut-out speed as detailed in the 2021 update.[510]

Table 145. Oregon offshore wind operational characteristics

Site	Lat.	Long.	Hub Height (m)	Rotor Diameter (m)	Turbine Rating (MW)	IRP CF (%)
Oregon South	42.69	-124.84	150	248	15	55.2%

Operational expenditures

Estimates for offshore wind operational expenditures use NREL's Oregon site-specific research to 2032 COD (**Table 146**). Beyond 2032, cost trajectories follow those provided in the NREL 2021 ATB.

Table 146. Summary of Oregon offshore wind operational expenditures

Operational Expenditures, offshore wind	
2019$	Oregon South
Fixed O&M ($/kW-year)	$97
Variable O&M ($/MWh)	$0

[510] Musial, Walter, Patrick Duffy, Donna Heimiller, and Philipp Beiter. 2021. Updated Oregon Floating Offshore Wind Cost Modeling, available at: nrel.gov/docs/fy22osti/80908.pdf.

Capital expenditures

NREL's Oregon site-specific research shows that capital expenditures are based on 2032 COD (2021 Update). Beyond 2032, cost trajectories follow NREL ATB. The NREL capital costs are adjusted to PGE's definition of overnight capital by removing the estimated decommissioning costs and financing costs during the construction period (AFUDC). Estimated decommissioning costs are included in the fixed lifetime cost of resource ownership as discussed in the details regarding PGE's fixed revenue requirements model, LUCAS (See **Appendix H, 2023 IRP modeling details**). The overnight capital cost for the earliest published year (2022) is detailed in **Table 147**.

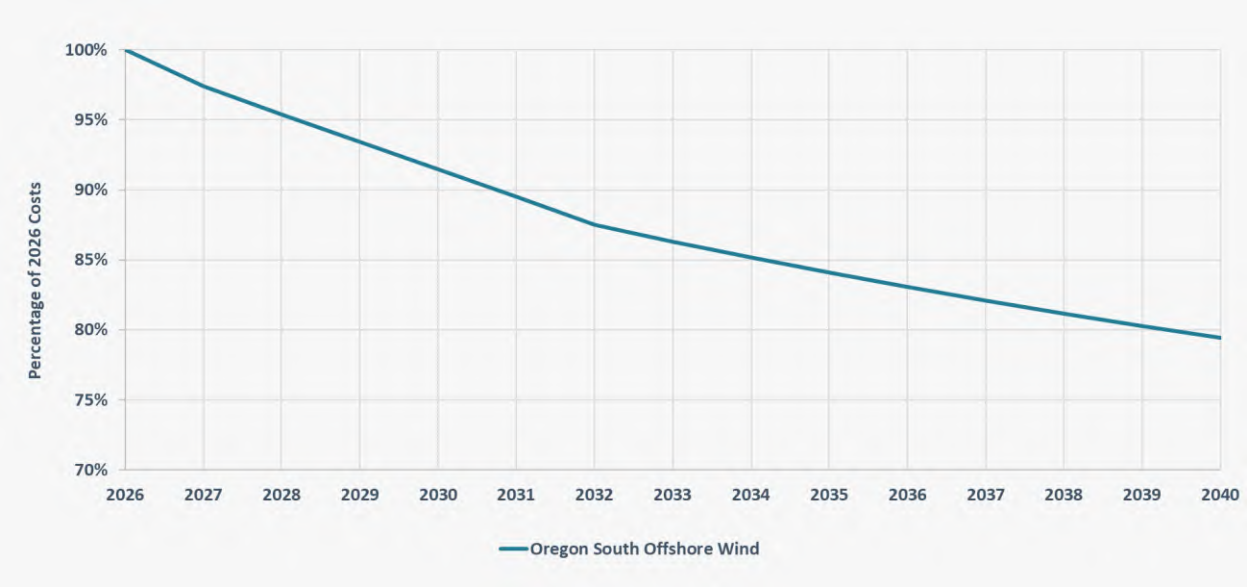
Table 147. Summary of Oregon offshore wind capital expenditures

Capital Expenditures, offshore wind	
2019 $/kW	Oregon South
Stated Capital Cost	$3,522
Less: Decommissioning	$34
Less: AFUDC	$142
Overnight Capital Cost	$3,346

Forward capital cost curve

Beginning with the earliest relevant year published by NREL, the overnight capital costs align with NREL's research to 2032 (**Figure 162**). Beyond 2032, cost curves developed by HDR for PGE's 2019 IRP are used.

Figure 162. Offshore wind capital cost trajectory



M.2.3 Solar photovoltaic

Technology description

Solar photovoltaic (solar PV) converts light from the sun into electrical energy. Cells generate direct current (DC) electrical energy. This conversion occurs within a cell; multiple cells are connected within a module. The total quantity of modules is the array. The power rating of the array is the DC capacity of the resource. The modules in the array can be either fixed at a given angle or tilted in one or two directions to track the sun. The orientation of the modules is typically defined with respect to azimuth (e.g., zero (0) if facing north, 180 if facing south).

Given that the array generates in DC, inverters are used to output AC electricity to the grid. The array's DC capacity related to the inverter's AC rating is referred to as the inverter load ratio (ILR). For example, an ILR of 2.0 means that the DC capacity of the array is twice the AC rating of the inverter. With this relationship, there will be periods when the array will have the potential to generate at levels higher than the inverter's rating. The inverter will limit the total output, and this excess energy from the array will be lost or "clipped."

Commercial status

Solar installations overall represented 45 percent of new generating capacity in 2021, up from 30 percent in 2017. The capacity installed in 2021 alone totaled approximately

18.9GWAC.[511] According to EIA data, approximately 60 GW of solar PV capacity was operational in the United States at the end of 2021.[512] Photovoltaic (PV) module efficiency has increased considerably over the past decade. An average standard monocrystalline module installed in 2021 was 20 percent efficient compared to approximately 14 percent in 2010.[513] National Renewable Energy Laboratory (NREL) reports recent increases in the share of bifacial modules installed, particularly in larger non-residential applications.[514] The median inverter loading ratio ("ILR" is the ratio of DC-to-AC capacity) for tracking solar PV projects installed in 2020 and 2021 was 1.34 and 1.33, respectively.[515] This value has been largely unchanged over the past five years. Solar PV installation with tracking continue to be preferred to fixed-tilt configurations. The trend towards tracking has grown significantly in the past eight years: in 2014, more solar PV capacity with fixed-tilt was installed than with tracking, by 2021, new tracking capacity additions represented nearly eight-times the capacity of fixed-tilt.[516]

Operational characteristics

Three Oregon locations are used to represent solar photovoltaic (PV) resources in the IRP: one central Oregon (east of Cascades) location near Christmas Valley, one location with a similar longitude (east of Cascades) but farther north near Wasco, and one location with a similar latitude as Wasco but in the Willamette Valley (west of the Cascades) near McMinnville (**Table 148**). A solar PV resource near Mead, Nevada, which will be accessed via incremental transmission action is included in PGE's analysis as well.

[511] Lawrence Berkeley National Laboratory. "Utility-Scale Solar, 2022 Edition" available at: https://emp.lbl.gov/utility-scale-solar
[512] 2021 Form EIA-860 Data - Schedule 3, 'Generator Data' (Operable Units Only). https://www.eia.gov/electricity/data/eia860/
[513] National Renewable Energy Laboratory (NREL). Spring 2022 Solar Industry Update. April 23, 2022. available at: https://www.nrel.gov/docs/fy22osti/82854.pdf
[514] *Id.*
[515] Lawrence Berkeley National Laboratory. "Utility-Scale Solar, 2022 Edition" available at: https://emp.lbl.gov/utility-scale-solar
[516] *Id.*

Table 148. Summary of solar PV operational characteristics 2026 COD

Site	Lat.	Long.	IRP CF%
Central Oregon (Christmas Valley)	43.25	-120.62	26.7%
Oregon Gorge (Wasco)	45.61	-120.7	25.3%
Willamette Valley (McMinnville)	45.21	-123.18	21.1%
Nevada (Mead)	35.89	-114.98	31.6%

Solar PV resources utilize single-axis tracking. Energy estimates are created in SAM using crystalline silicon modules with 21 percent nominal efficiency and inverter efficiency of 98 percent.[517] The ILR is 1.34, consistent with the assumptions in the NREL ATB.

Similar to the rationale for onshore wind, resource configurations remain constant across the four Solar PV sites. This focuses any analysis on solar resource variations rather than attempting to optimize each site's design. It is expected that developers in the marketplace will employ their expertise to design an optimal solar PV resource for any specific location. An hourly generation profile is simulated for each year of weather data for each site listed in **Table 148**. These hourly generation profiles are produced using SAM. The profiles are used as inputs to Sequoia. The hourly shape for the representative year is used as input to Aurora for energy modeling. Consistent with the NREL ATB assumption, annual degradation of 0.5 percent is applied to arrive at the IRP capacity factor listed in **Table 148**.

Operational expenditures

Operational expenditures for the representative solar PV plant are sourced from the NREL 2021 ATB as well (**Table 149**). The general categories of costs included in operational expenditures are listed earlier.

[517] Feldman, David, Vignesh Ramasamy, Ran Fu, Ashwin Ramdas, Jal Desai, and Robert Margolis. 2021. U.S. Solar Photovoltaic System Cost Benchmark: Q1 2020. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-77324. https://www.nrel.gov/docs/fy21osti/77324.pdf#page=66

Table 149. Summary of solar PV operational expenditures

Operational Expenditures, solar photovoltaic				
2019$	Central Oregon	Oregon Gorge	Willamette Valley	Mead, Nevada
Fixed O&M ($/kW-year)	$23	$23	$23	$23
Variable O&M ($/MWh)	$0	$0	$0	$0

Capital expenditures

Capital expenditures for the representative solar PV plant are sourced from the NREL 2021 ATB as well (**Table 150**). The general categories of costs included in capital expenditures are listed earlier.

Table 150. Summary of solar PV capital expenditures

Capital Expenditures, solar photovoltaic				
2019 $/kWac	**Central Oregon**	**Oregon Gorge**	**Willamette Valley**	**Mead, Nevada**
Overnight capital	$1,347	$1,347	$1,347	$1,347
Less: Transmission Line Cost	$71	$71	$71	$71
Overnight EPC Capital Cost -Ex Interconnect Cost	$1,277	$1,277	$1,277	$1,277

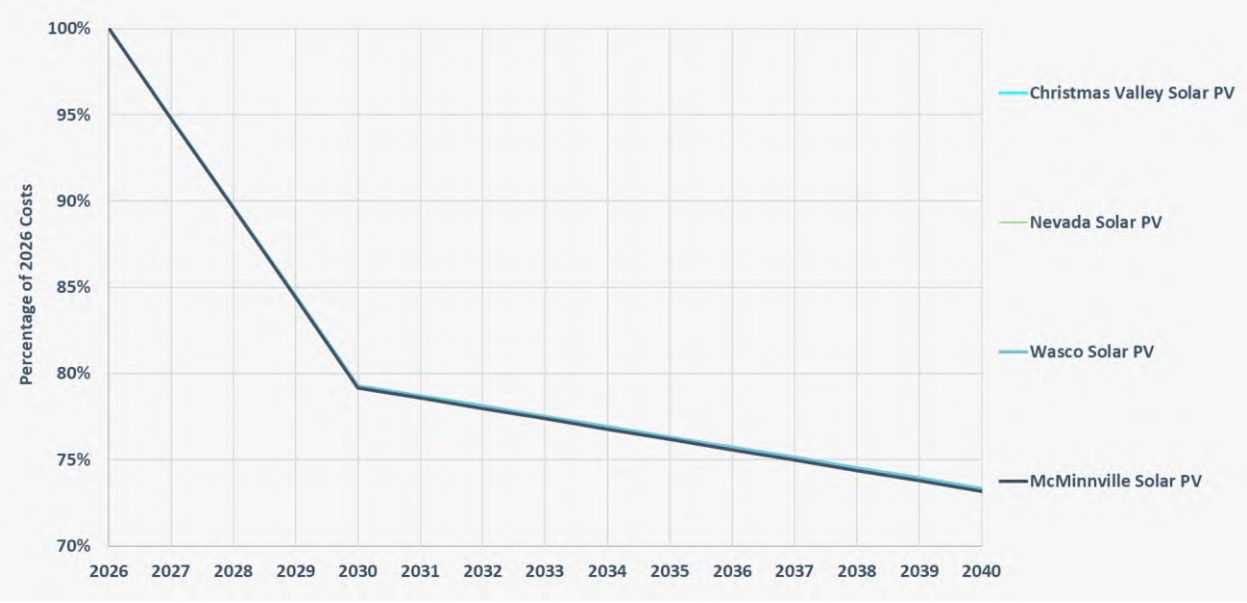
Capital Expenditures, solar photovoltaic				
Location Adjustment	1	1	1.05	1
Location-adjusted Overnight Capital Cost	$1,277	$1,277	$1,340	$1,277

Costs are presented in units of $/kWAC based on the aggregated inverter rating. The locational adjustments applied to Central Oregon and Oregon Gorge resources are based on an average of the EIA factors for Portland, Boise, and Spokane. The location adjustment factor for the Willamette Valley resource corresponds to the EIA factor for Portland. Note that NREL documentation includes land acquisition costs as a capital expenditure component.

Forward capital cost curve

The solar PV resources at different locations share a common forward capital cost trajectory. The NREL 2021 ATB projection of future capital costs for the Reference Case scenario are shown in **Figure 163**.

Figure 163. Solar PV capital cost trajectory



M.2.4 Geothermal

Technology description

Geothermal energy is the heat contained in the Earth's interior. This heat is typically accessed for electricity generation by the drilling of injection and production wells. Various technologies are used to harness the energy in a particular location depending on the nature of that specific resource, generally described by the temperature. Geothermal energy can also be employed for purposes aside from electricity generation; these so-called "direct use" cases include building and district heating, and recreation/therapeutic bathing.

Heat recovery generally generates electricity from geothermal resources in the form of hot water or steam via a well drilled into the earth. Resources are broadly categorized as either hydrothermal or enhanced geothermal systems (EGS) depending on the groundwater and subsurface rock structure characteristics.

Hydrothermal resources are those where the naturally occurring rock structure and groundwater flow are sufficient to support energy recovery. These may be referred to as "conventional" geothermal resources.

In contrast, EGS resources have sufficient heat but lack the groundwater or rock structure, allowing for efficient energy recovery. These resources require engineering techniques to introduce liquid or allow liquid flow within the rock structure.

EGS resources can be further classified based on their location with respect to existing conventional hydrothermal resources. When EGS techniques are applied within existing hydrothermal developments the resource is referred to as "in-field" EGS. This might happen to promote the recovery of energy from an otherwise non-productive well, for example. "Near-field" EGS occurs beyond the geological boundaries of a conventional resource where applying EGS engineering techniques can expand the development of cost-effective resources. "Deep" EGS refers to developing geothermal resources beyond those relying on hydrothermal fields. Areas of sufficient temperature would be identified and then accessed via drilled wells at depths of up to 7 km. The use of engineering techniques to introduce liquid and fracture the rock structure could allow for the recovery of vast amounts of energy.

In general, geothermal energy generates electricity by using the hot water or steam produced from within the Earth to turn a turbine and generator. The condensed liquid is then injected back into the ground. The technology to utilize that hot water or steam is generally dictated by the operating temperature of the specific resource.

Flash power plants are used at resources with relatively higher temperatures, generally exceeding 200 degrees Celsius. In this application, the heated fluid directly drives the turbine.

Binary power plants employ a heat exchanger to extract energy from the heated fluid and operate the turbine via a Rankine cycle (fluid movement through a system arising from temperature differences). This technology is generally used at resources with temperatures in the range of 100 – 200 degrees Celsius.

All else equal, it's expected that flash plants result in lower capital expenditures and higher operating efficiencies than binary plants.

Pairing resource descriptions and the technology options arising from the characteristics of a given resource results in the following six resource and technology categories:

(1) Hydrothermal Flash or (2) Hydrothermal Binary.

(3) Near-field EGS Flash or (3) Near-field EGS Binary.

(5) Deep EGS Flash or (6) Deep EGS Binary.

Commercial status

Nationally, according to EIA data, nearly 4 GW of geothermal generating capacity was operable at the end of 2021.[518] More than 3 GW are currently operating in the WECC. However, only one commercial project operates in Oregon, representing approximately 29 MW. The majority, over 95 percent, of regional geothermal capacity is in California and Nevada, representing 67 percent and 30 percent, respectively. Roughly 30 percent of California's geothermal capacity is at Calpine's nearly 700 MW The Geysers project is north of Santa Rosa.[519]

The only commercial geothermal project currently operating in Oregon is the Neal Hot Springs plant near Vale in eastern Oregon. The 28.5 MW project, which began operation in 2012, is jointly owned by Ormat and Enbridge; Idaho Power is the off-taker.

Operational characteristics

The representative geothermal plant in the RFP uses resource cost characteristics consistent with a hydrothermal flash resource from the NREL ATB.

[518] 2021 Form EIA-860 Data - Schedule 3, 'Generator Data' (Operable Units Only)
[519] S&P Global Market Intelligence (work paper)

Operational expenditures

Fixed and variable operating expenditures are sourced from the NREL ATB. These costs represent the average annual expenditures for operations and maintenance over the resource's life (**Table 151**). These include the costs of plant and well-field components.

Table 151. Summary of geothermal flash operational expenditures

Operational Expenditures, geothermal flash	
2019$	**Oregon**
Fixed O&M ($/kW-year)	$137
Variable O&M ($/MWh)	$0

Capital expenditures

Capital expenditures for the representative geothermal plant are sourced from the NREL 2021 ATB as well (**Table 152**). In addition to the general cost categories listed earlier, geothermal-specific costs include: "exploration, confirmation drilling, well field development, reservoir stimulation (EGS), plant equipment" and "plant construction, power plant equipment, well-field equipment, and components for wells (including dry/noncommercial wells)."[520]

Table 152. Summary of geothermal flash capital expenditures

Capital Expenditures, geothermal flash	
2019 $/kW	**Oregon**
Overnight capital	$4,440
Less: Transmission Line Cost	$30
Overnight EPC Capital Cost -Ex Interconnect Cost	$4,410
Location Adjustment	1.04
Location-adjusted Overnight Capital Cost	$4,601

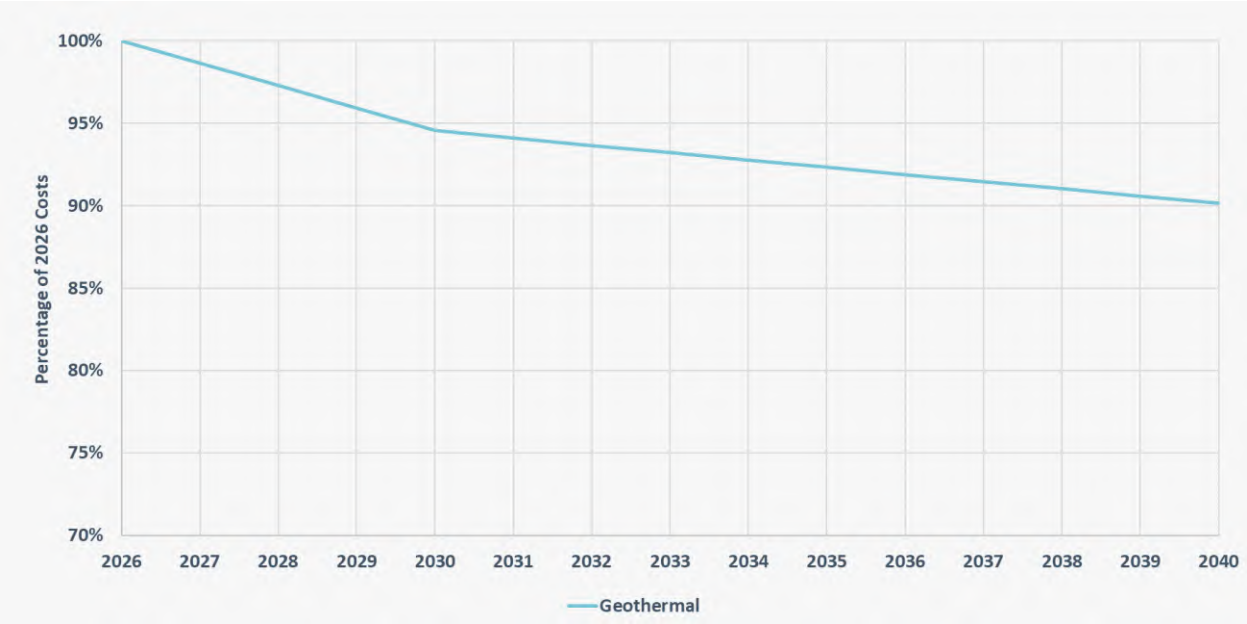
The locational adjustment is based on an average of the EIA factors provided by Portland, Boise, and Spokane.

[520] NREL 2021 Electricity ATB. Available at: https://atb.nrel.gov/electricity/2021/geothermal

Forward capital cost curve

The NREL 2021 ATB projection of future capital costs for the Reference Case scenario are presented in **Figure 164**:

Figure 164. Geothermal capital cost trajectory



M.3 Energy storage resources

M.3.1 Battery energy storage

Technology description

PGE's IRP uses lithium-ion technology for analysis of battery energy storage systems (BESS) in this IRP. The cost and performance of storage durations ranging from 2-24 hours are evaluated.

Commercial status

According to EIA data, at the end of 2021, nearly 5 GW of battery energy storage capacity was operable in the United States. More than 3 GW of that total came online in 2021 alone.[521]

[521] 2021 Form EIA-860 Data - Schedule 3, 'Generator Data' (Operable Units Only)

Operational characteristics

The representative battery energy storage systems (BESS) costs and performance characteristics are now based on lithium-ion technology. These data are sourced from the NREL ATB for durations up to eight hours; IRP cost assumptions for longer durations apply the NREL ATB methodology and are derived from the same energy and power cost estimates.

Operational expenditures

The NREL ATB derives fixed operational expenditures as a percentage (2.5 percent) of the overnight capital for BESS. As a result, these expenditures vary with by battery duration as summarized in **Table 153**. Fixed operational expenditures are inclusive of amounts required to compensate for degradation to enable the battery system to have a constant capacity throughout its life.[522]

Table 153. Summary of BESS operational expenditures

Operational Expenditures, battery energy storage system						
2019$	**2 Hour**	**4 Hour**	**6 Hour**	**8 Hour**	**16 Hour**	**24 Hour**
Fixed O&M ($/kW-year)	$20	$34	$48	$62	$117	$172
Variable O&M ($/MWh)	$0	$0	$0	$0	$0	$0

Capital expenditures

The capital expenditures for BESS are sourced from the NREL 2021 ATB (**Table 154**). The general categories of costs included in capital expenditures are listed earlier. The capital expenditures for BESS are a function of energy and power capacities:

Total system cost ($/kW) = Battery Energy Cost ($/kWh) * Storage Duration (hr.) + Battery Power Cost ($/kW)

[522] NREL 2021 Electricity ATB. Available at: https://atb.nrel.gov/electricity/2021/utility-scale_battery_storage

Table 154. Summary of BESS capital expenditures

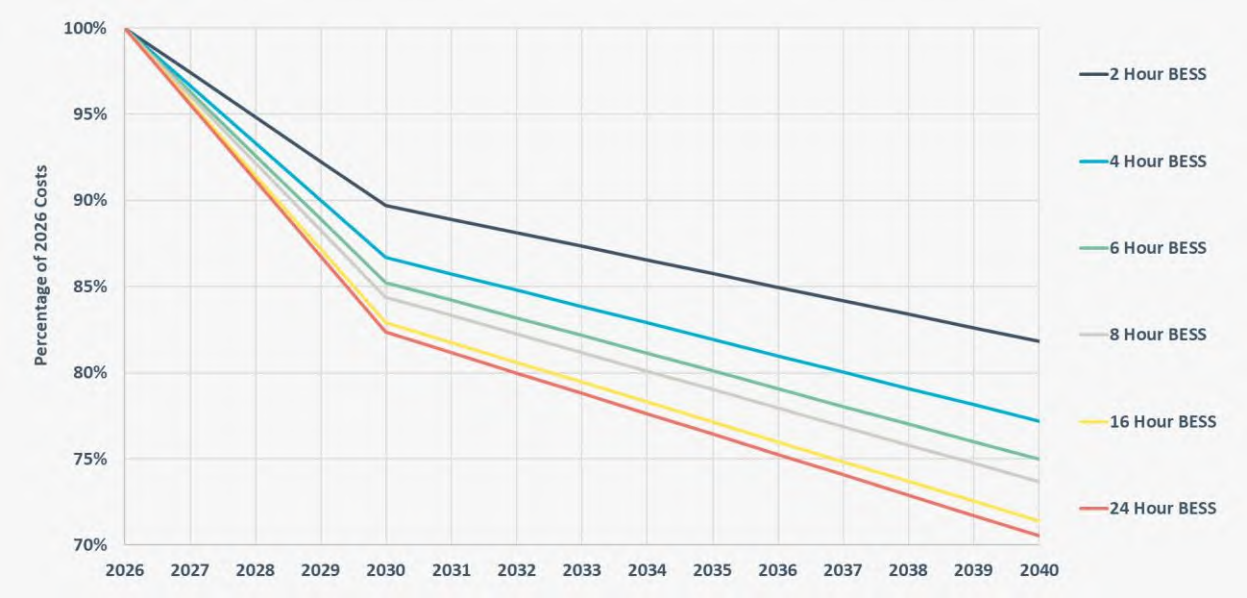
Capital Expenditures, battery energy storage system						
2019 $/kWac	**2 Hour**	**4 Hour**	**6 Hour**	**8 Hour**	**16 Hour**	**24 Hour**
Overnight capital	$792	$1,331	$1,870	$2,410	$4,567	$6,724
Location Adjustment	1.02	1.02	1.02	1.02	1.02	1.02
Location-adjusted Overnight Capital Cost	$810	$1,362	$1,914	$2,466	$4,674	$6,881

The location adjustment is based on an average of the EIA factors provided by Portland, Boise, and Spokane.

Forward capital cost curve

Given that total capital costs are a function of the energy (weighted by duration) and power components, the trajectory of future capital costs for various durations depends on the developments assumed for these components. The NREL 2021 ATB future capital costs project a more rapid decline in energy component-related costs than power component-related costs. The result is that capital costs for longer-duration BESS decline more quickly than shorter duration. The Reference Case scenario is presented in **Figure 165.**

Figure 165. Battery energy storage system capital cost trajectory



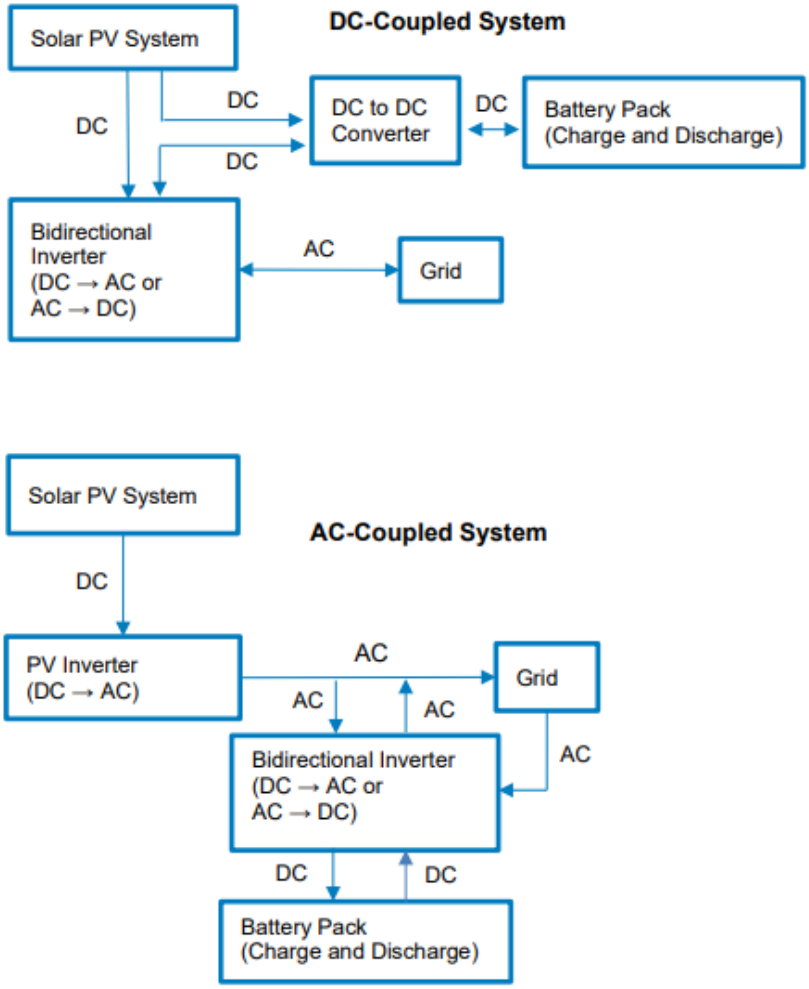
M.3.2 Hybrid solar photovoltaic + battery energy storage

Technology description

"Hybrid" resources pair renewable and storage resources behind a single interconnection. Hybrid resources could include solar PV with energy storage, wind with energy storage, and wind and solar PV with energy storage (such as PGE's Wheatridge Renewable Energy Facility), among others. In this 2023 IRP, PGE models solar PV with battery energy storage hybrid resources. Multiple elements are required when describing a solar + BESS resource, including resource coupling (AC- or DC-coupled), solar-to-storage ratio, solar-to-inverter ratio ("inverter loading ratio" as described previously), and storage duration. The solar and BESS components could be coupled on the AC side of the inverters (AC-coupled) or the DC side of the inverter (DC-coupled). When AC-coupled, the battery, and solar resources use separate inverters. The IRP assumption of DC coupling is consistent with the NREL ATB. **Figure 166** illustrates the basic elements of these two configurations.[523]

[523] Feldman, David, Vignesh Ramasamy, Ran Fu, Ashwin Ramdas, Jal Desai, and Robert Margolis. 2021. U.S. Solar Photovoltaic System Cost Benchmark: Q1 2020. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-77324. https://www.nrel.gov/docs/fy21osti/77324.pdf.

Figure 166. Illustrative DC- and AC-coupled solar + BESS



Commercial status

Hybrid solar and storage were the dominant form of hybrid resources by the end of 2021. Solar and storage hybrids also saw a significant installed capacity increase; nearly 90 percent of all hybrid solar and storage resources came online in 2021 (when measured on a storage capacity basis, or ~77 percent when viewed on a generation capacity basis).[524]

[524] U.S. Department of Energy. "Land-based Wind Market Report: 2022 Edition." Available at: https://emp.lbl.gov/sites/default/files/2022_land_based_wind_market_report.pdf

Operational characteristics

Given the large number of hybrid resource permutations that would arise from investigating sensitivities around each design element, the IRP simplifies the analysis to include two representative solar and BESS hybrid resources at two locations (**Table 155**). At each location these two hybrid resources:

- Employ a DC-coupled configuration.
- Differ in the ratio of solar-to-storage capacity. The two representative hybrid resources tested in this IRP are differentiated by this ratio, with one resource featuring a storage power capacity equivalent to the inverter rating (1.0) and one resource with a storage power capacity equal to one-half of the inverter rating (0.5).
- Utilize the Christmas Valley and McMinnville solar locations discussed previously; however, the solar resources differ regarding the inverter loading ratio. While the standalone solar resource is modeled with an ILR of 1.34, the hybrid solar resource has an ILR of 1.50.
- Use BESS with a four-hour storage duration.

Table 155. Summary of hybrid solar PV + BESS operational characteristics

Hybrid PV + BESS				
Description	Christmas Valley Solar w/ 4 Hour Li-Ion (0.5)	Christmas Valley Solar w/ 4 Hour Li-Ion (1.0)	McMinnville Solar w/ 4 Hour Li-Ion (0.5)	McMinnville Solar w/ 4 Hour Li-Ion (1.0)
Location (Lat., Long.)	43.25, -120.62	43.25, -120.62	43.25, -120.62	43.25, -120.62
Capacity (MWac)	75	75	75	75
Duration (hours)	4	4	4	4
Round-Trip Efficiency	86%	86%	86%	86%
Solar Capacity Factor[525]	28.6%	28.6%	23.0%	23.0%
Solar ILR	1.50	1.50	1.50	1.50

[525] Lifetime capacity factor inclusive of 0.5 percent annual degradation; does not account for battery storage of clipped energy.

Hybrid PV + BESS				
Solar Capacity (MWdc)	112.5	112.5	112.5	112.5
Storage Ratio	1:2	1:1	1:2	1:1
Storage Capacity (MW)	37.5	75	37.5	75

Operational expenditures

Solar PV and BESS values from the NREL 2021 ATB are the basis for the operational expenditures for the hybrid resources (**Table 156**).

Table 156. Summary of hybrid solar PV + BESS operational expenditures

Operational Expenditures			Hybrid PV + BESS	
2019$	Christmas Valley Solar w/ 4 Hour Li-Ion (0.5)	Christmas Valley Solar w/ 4 Hour Li-Ion (1.0)	McMinnville Solar w/ 4 Hour Li-Ion (0.5)	McMinnville Solar w/ 4 Hour Li-Ion (1.0)
Fixed O&M ($/kW-year)	$40	$53	$41	$54
Variable O&M ($/MWh)	$0	$0	$0	$0

Capital expenditures

The capital expenditures for the hybrid resources are sourced from the NREL 2021 ATB and cited NREL research (**Table 157**). The ILR of the solar resource in the hybrid configuration differs slightly from the standalone solar PV resource. The PV module and balance of system costs were scaled based on relationships from NREL research to approximate the difference in ILR.[526] Additionally, costs were scaled to estimate the two storage-to-inverter ratios mentioned previously. The general categories of costs included in capital expenditures are listed earlier.

Table 157. Summary of hybrid solar PV + BESS capital expenditures

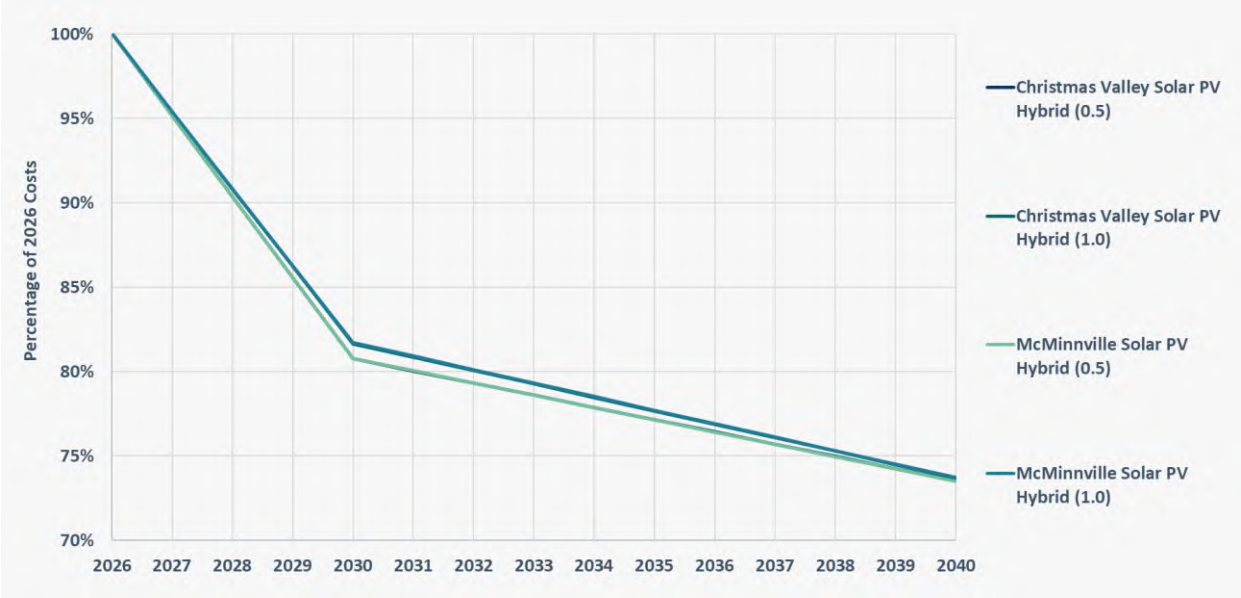
Capital Expenditures, hybrid PV + BESS				
2019 $/kWac	Christmas Valley Solar w/ 4 Hour Li-Ion (0.5)	Christmas Valley Solar w/ 4 Hour Li-Ion (1.0)	McMinnville Solar w/ 4 Hour Li-Ion (0.5)	McMinnville Solar w/ 4 Hour Li-Ion (1.0)
O/N Capital Cost ($/kW)	$1,931	$2,558	$1,995	$2,622
O/N Capital Cost ($/kWh)	$483	$640	$499	$655

Forward capital cost curve

The hybrid capital costs are a function of the solar PV and BESS components. As such, the trajectory of future capital costs for various durations depends on the developments assumed for those components. The NREL 2021 ATB future capital costs project a slightly faster decline in solar PV costs than BESS costs. The result is that capital costs for the hybrid pairings with relatively more solar than BESS (those with lower storage-to-inverter ratios) decline more quickly. The Reference Case scenario is presented in the following figure (**Figure 167**):

[526] NREL 2021 Electricity ATB. Available at: https://atb.nrel.gov/electricity/2021/utility-scale_pv-plus-battery#comparison_with_alternate_configurations

Figure 167. Reference case cost curve



M.3.3 Pumped hydroelectric energy storage

Technology description

Pumped hydropower energy storage resources generally employ two reservoirs at different locations. Water is pumped to the higher-elevation reservoir and stored, which converts electrical energy to operate the pumps into potential energy (charging). When the water is released from the reservoir it flows through a turbine, generating electricity (discharging).[527]

Commercial status

According to EIA data, approximately 22 GW of pumped hydropower capacity was operable in the United States at the end of 2021. However, no new capacity has come online in nearly a decade, with 370 MW of new capacity operable since 1995.[528]

[527] Portland General Electric. "THERMAL AND PUMPED STORAGE GENERATION OPTIONS." Prepared by HDR, Inc. as External Study D to 2019 Integrated Resource Plan. https://downloads.ctfassets.net/416ywc1laqmd/6KTPcOKFlLvXpf18xKNseh/271b9b966c913703a5126b2e7bbbc37a/2019-Integrated-Resource-Plan.pdf#page=556

[528] 2021 Form EIA-860 Data - Schedule 3, 'Generator Data' (Operable Units Only)

Operational characteristics

The pumped-storage hydropower resource is a 600 MW closed-loop system (water is pumped between two reservoirs and is not connected to a water system) providing 10 hours of energy storage. The availability of this resource is geographically limited. Costs and performance attributes of this representative resource are based on an average of six proposed regional closed-loop projects gathered from information published by the Northwest Power and Conservation Council.

Operational expenditures

Operational expenditures for a representative pumped hydropower storage project in the pacific northwest are sourced from data published by the Northwest Power and Conservation Council in support of the 2021 Northwest Power Plan (**Table 158**).

Table 158. Summary of pumped hydropower storage operational expenditures

Operational Expenditures, pumped hydropower storage	
2019$	PNW
Fixed O&M ($/kW-year)	$17
Variable O&M ($/MWh)	$0

Capital expenditures

The capital cost for a representative pumped hydropower storage project in the pacific northwest is sourced from data published by the Northwest Power and Conservation Council in support of the 2021 Northwest Power Plan. The developer capital cost reported in **Table 159** is an average of the closed-loop system's data. To this cost, an allowance for the owner's expense is applied. The 20 percent owner's cost allowance compares with the 20 percent used by in other regional IRPs[529] on very similar data and approximately 25 percent used by PGE in the 2019 IRP based on data furnished by HDR, Inc. (**Table 159**).

[529] PacifiCorp. "2020 Renewable Resources Assessment." Revision 1, August 2020. https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2021-irp/2021-irp-support-and-studies/2020-10-01_PacifiCorp_2020_Renewable_Resource_Study_Report_FINAL.pdf#PAGE=44

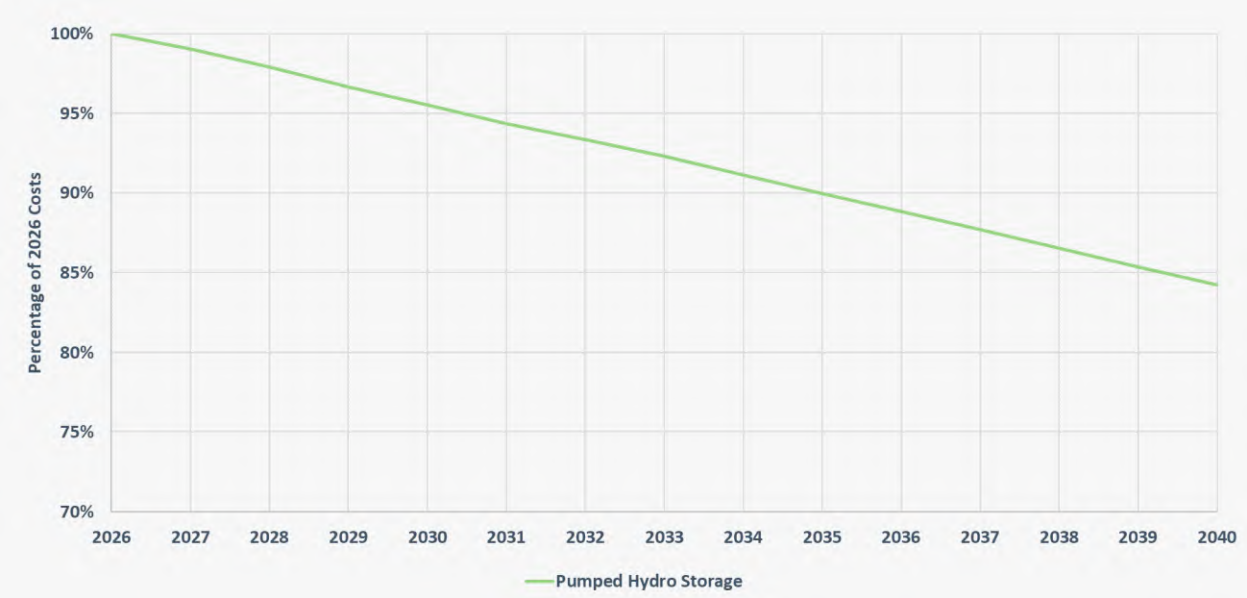
Table 159. Summary of pumped hydropower storage capital expenditures

Capital expenditures, pumped hydropower storage	
2019 $/kW	PNW
Developer Capital Cost	$2,135
Owner's Cost Allowance %	20%
Owner's Cost Allowance $/kW	$427
Overnight Capital Cost	$2,562

Forward capital cost curve

The HDR, Inc., projection of future capital costs for the Reference Case scenario are presented in **Figure 168**.[530]

Figure 168. Pumped hydropower storage capital cost trajectory:



[530] Portland General Electric. "THERMAL AND PUMPED STORAGE GENERATION OPTIONS." Prepared by HDR, Inc. as External Study D to 2019 Integrated Resource Plan. https://downloads.ctfassets.net/416ywc1laqmd/6KTPcOKFlLvXpf18xKNseh/271b9b966c913703a5126b2e7bbbc37a/2019-Integrated-Resource-Plan.pdf#page=522

M.3.4 Hydrogen-fueled CCCT with production and storage

Technology description

This resource is representative of a renewable ("green") hydrogen-fueled combined-cycle combustion turbine (CCCT) with hydrogen fuel production and storage. An electrolyzer uses electricity to produce hydrogen from water. The hydrogen (H2) is then compressed and stored in underground pipes; storage is sufficient to provide 24 hours of fuel supply. Where available, geologic formations (e.g., salt caverns) present an alternative means of fuel storage. The hydrogen fuel feeds the CCCT to generate electricity.

Commercial status

In June 2022, the U.S. Department of Energy (DOE) issued a loan guarantee in excess of $500 million to support the development of a hydrogen production and energy storage facility in Delta, Utah. 220 MW of electrolyzer capacity will produce hydrogen for storage in salt caverns. The hydrogen will then be available to fuel an 840 MW CCCT at the Intermountain Power Project.[531] The CCCT is expected to begin operation with blended hydrogen and natural gas fuel in 2025.[532] DOE states that the "scale of deployed electrolyzers as well as the use of salt caverns to store hydrogen are both significant innovations."[533]

Operational characteristics

For modeling purposes, the CCCT is consistent with the natural gas-fired resource described in **Section M.5 Natural gas-fueled resources**. Cost and performance parameters for this resource's hydrogen production and storage components are based on the research and analyses of Mongrid and Hunter.[534,535] The CCCT is paired with an equivalent electrolyzer capacity. As illustrated in the capital expenditure as shown in **Table 162**, the electrolyzer may be the primary capital expenditure on the H2 production side of the resource; reducing the electrolyzer capacity will lower costs but will result in longer H2 production (charging) times. The 1:1 pairing produces approximately seven metric tons of H2 per hour or approximately

[531] https://www.energy.gov/lpo/advanced-clean-energy-storage
[532] S&P Global Market Intelligence
[533] https://www.energy.gov/lpo/advanced-clean-energy-storage
[534] Mongrid et al., "2020 Grid Energy Storage Technology Cost and Performance Assessment." Pacific Northwest National Laboratory. December 2020. Retrieved from: https://www.pnnl.gov/sites/default/files/media/file/Final%20-%20ESGC%20Cost%20Performance%20Report%2012-11-2020.pdf
[535] Hunter et al., "Techno-economic analysis of long-duration energy storage and flexible power generation technologies to support high variable renewable energy grids." Retrieved from: https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3720769

38 percent of the fuel needed to operate the CCCT at full load for one hour. Consistent with the research, electrolyzer efficiency is assumed to be 72.5 percent. The CCCT is approximately 52 percent efficient (based on a perfect heat rate of 3,412 Btu/kWh and a CCCT lifetime heat rate of 6,561 Btu/kWh).

Table 160. Summary of CCCT w/ H2 operational characteristics

Operational Characteristics, combined-cycle CT (1 x 1) w/ H2 production/storage	
Capacity (MW average lifetime)	407
Heat Rate (Btu/kWh average lifetime)	6,561
Storage Duration (Hours)	24
Electrolyzer Efficiency (%)	72.50%
Planned outage rate	3.88%
Forced outage rate	2.19%

Operational expenditures

The H_2 production and storage operational costs are derived from Mongrid and Hunter and combined with the generation operational expenditures associated with the natural gas-fired CCCT (**Table 161**) discussed in **Appendix M.5.2, Combined-cycle combustion turbine**.[536,537]

Table 161. Summary of CCCT w/ H2 operational expenditures

Operational Expenditures, combined-cycle CT (1 x 1) w/ H2 production/storage	
2019$	
Fixed O&M ($/kW-year)	$27
Variable O&M ($/MWh)	$4

[536] Mongrid, et al., "2020 Grid Energy Storage Technology Cost and Performance Assessment." Pacific Northwest National Laboratory. December 2020. Retrieved from: https://www.pnnl.gov/sites/default/files/media/file/Final%20-%20ESGC%20Cost%20Performance%20Report%2012-11-2020.pdf

[537] Hunter, et al., "Techno-economic analysis of long-duration energy storage and flexible power generation technologies to support high variable renewable energy grids." Retrieved from: https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3720769

Capital expenditures

The H_2 production and storage component costs are derived from Mongrid and Hunter and summarized in **Table 162**.[538,539] Values are in 2019 dollars, and production costs are based on energy input to the system. These costs represent the components necessary to produce and store hydrogen for later combustion in an H-class CCCT.

Table 162. Summary of CCCT w/ H2 capital expenditures

Capital Expenditures, combined-cycle CT (1 x 1) w/ H2 production/storage	
2019 $kW	
PEM Electrolyzer (kW input)	$1,534
Rectifier (kW input)	$133
Compressor (kW input)	$40
Controls & Integration (kW input)	$20
Total Production (kW input)	$1,728
Pipe Storage (24 hours)	$710
Owner's Costs	$306
Total Production + Storage	$2,745

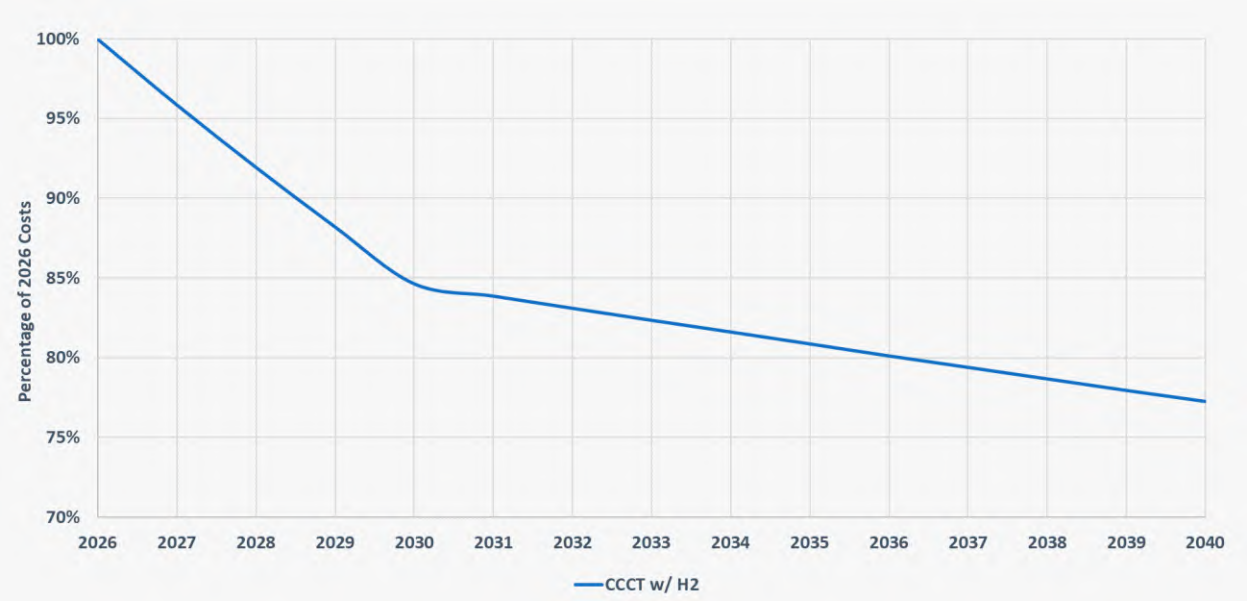
The owner's cost allowance of 12.5 percent (owner's cost in EIA research applicable to hydrogen fuel cell resource) is added to the production and storage values.[540]

Costs associated with the CCCT are based on the H-class CCCT detailed in **Appendix M.5.2, Combined-cycle combustion turbine**.

[538] Mongrid, et al., "2020 Grid Energy Storage Technology Cost and Performance Assessment." Pacific Northwest National Laboratory. December 2020. Retrieved from: https://www.pnnl.gov/sites/default/files/media/file/Final%20-%20ESGC%20Cost%20Performance%20Report%2012-11-2020.pdf
[539] Hunter, et al., "Techno-economic analysis of long-duration energy storage and flexible power generation technologies to support high variable renewable energy grids." Retrieved from: https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3720769
[540] EIA AEO 2020. "Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies." Prepared by Sargent & Lundy.

Forward capital cost curve

Figure 169. Hydrogen production/storage/CCCT capital cost trajectory



M.4 Dispatchable resources

M.4.1 Biomass

Technology description

Power production using biomass fuel is similar to other solid fuel power plants in that a boiler is used to combust fuel and generate steam to drive a turbine and produce electricity. The representative biomass-fueled resource uses a bubbling fluidized bed (BFB) design to combust wood chips. NOx emissions are controlled in-furnace using over-fire air (OFA), and with a high dust selective catalytic reduction (SCR) system, SO2 emissions from wood firing are inherently low and therefore are uncontrolled. Particulate matter is controlled using a pulse jet fabric filter baghouse."[541]

[541] EIA AEO 2020. "Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies." Prepared by Sargent & Lundy.

Commercial status

According to EIA data, at the end of 2021, wood and wood waste biomass capacity in the United States totaled more than 9 GW.[542]

Operational characteristics

Table 163. summary of biomass operational characteristics

Operational Characteristics, biomass	
2019$	BFB
Capacity (MW average lifetime)	50
Heat Rate (Btu/kWh average lifetime)	13,300
Planned outage rate	3.07%
Forced outage rate	6.03%

Operational expenditures

Table 164. Summary of biomass operational expenditures

Operational Expenditures, biomass	
2019$	BFB
Fixed O&M ($/kW-year)	$126
Variable O&M ($/MWh)	$5

[542] 2021 Form EIA-860 Data - Schedule 3, 'Generator Data' (Operable Units Only)

Capital expenditures

Table 165. Summary of biomass capital expenditures

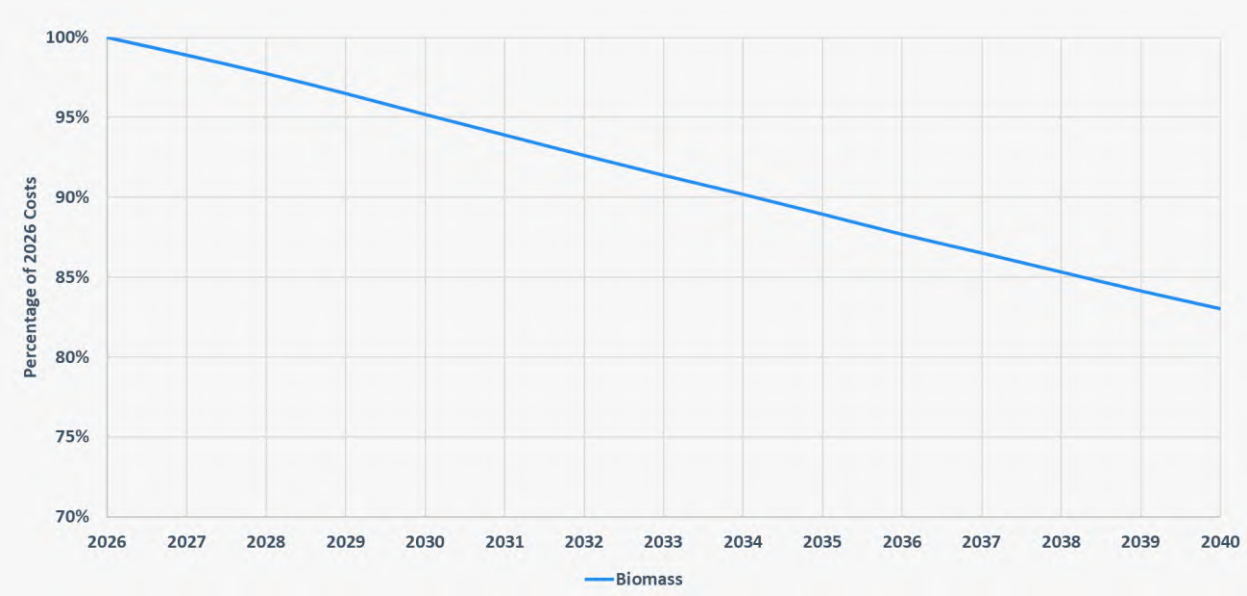
Capital Expenditures, biomass	
2019 $/kW	BFB
Overnight capital	$4,097
Transmission Line Cost	$24
Overnight EPC Capital Cost -Ex Interconnect Cost	$4,073
Location Adjustment	1.09
Location-adjusted Overnight Capital Cost	$4,453

The location adjustment is based on an average of the EIA factors provided by Portland, Boise, and Spokane.

Forward capital cost curve

The EIA 2020 AEO projection of future capital costs for the Reference Case scenario are presented in **Figure 170**.

Figure 170. Biomass capital cost trajectory



M.4.2 Nuclear

Technology description

The AP1000 advanced passive design and a representative small modular reactor (SMR) design are considered two nuclear-fueled generating options. This description is excerpted from EIA:

"The AP1000 improves on previous nuclear designs by simplifying the design to decrease the number of components, including piping, wiring, and valves. The AP1000 design is standardized as much as possible to reduce engineering and procurement costs. The AP1000 component reductions from previous designs are approximately:

- 50 percent fewer valves
- 35 percent fewer pumps
- 80 percent less pipe
- 45 percent less seismic building volume
- 85 percent less cable

The AP1000 design uses an improved passive nuclear safety system that requires no operator intervention or external power to remove heat for up to 72 hours.

The AP1000 uses a traditional steam cycle similar to other generating facilities such as coal or CC units. The primary difference is that the AP1000 uses enriched uranium as fuel instead of coal or gas as the heat source to generate steam. The enriched uranium is contained inside the pressurized water reactor. The AP1000 uses a two-loop system in which the heat generated by the fuel is released into the surrounding pressurized reactor cooling water. The pressurization allows the cooling water to absorb the released heat without boiling. The cooling water then flows through a steam generator that provides steam to the turbine for electrical generation."[543]

The SMR resource is based on a representative design of 12 reactor modules, each representing 50 MW or 600 MW in total. "The mechanical systems of an SMR are much smaller than those of a traditional nuclear plant. The mechanical systems are similar to that of an advanced nuclear power plant. Each reactor module comprises a nuclear core and steam generator within a reactor vessel, enclosed within a containment vessel in a vertical

[543] EIA AEO 2020. "Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies." Prepared by Sargent & Lundy. Available at: https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf

orientation. The nuclear core is located at the module's base, with the steam generator located in the upper half of the module. Feedwater enters, and steam exits through the top of the vessel towards the steam turbine. The entire containment vessel sits within a water-filled pool that provides cooling and passive protection in a loss of power event. All 12 reactor modules sit within the same water-filled pool housed within a typical reactor building.

Each SMR module uses a pressurized water reactor design to achieve a high level of safety and reduce the number of components required. To improve licensing and construction times, each reactor is prefabricated at the OEM's facility and shipped to the site for assembly. The compact integral design allows each reactor to be shipped by rail, truck, or barge.

Each module has a dedicated balance of plant (BOP) system for power generation. Steam from the reactor module is pumped through a steam turbine connected to a generator for electrical generation. Each BOP system is fully independent, containing a steam turbine and all necessary pumps, tanks, heat exchangers, electrical equipment, and controls for operation. This allows for the independent operation of each reactor module. Each reactor module's independent operation provides greater efficiencies at lower operating loads when dispatched capacity is reduced.

Additionally, the modular design of the reactors allows for refueling and maintenance of the individual reactors without requiring an outage of the entire facility. An extra reactor bay includes the pool housed with the reactor building. This extra bay allows for removing individual reactors for maintenance without impacting the remaining reactors."[544]

Commercial status

At the end of 2021, nearly 100 GW of nuclear capacity was operable in the United States, according to EIA data. Watts Bar Unit 2, which came online in 2016, is the most recent nuclear resource addition. Nearly 3 GW are currently proposed to come online between 2023 and year-end 2030, including six SMR units planned for Utah Associated Municipal Power Systems at the Department of Energy (DOE) Idaho National Laboratory.[545]

[544] *Id.*
[545] 2021 Form EIA-860 Data - Schedule 3, 'Generator Data' (Operable Units Only)

Operational characteristics

Table 166. Summary of nuclear-powered generating resource operational characteristics

Operational Characteristics	Nuclear	
	SMR	AP1000
Capacity (MW average lifetime)	600	2,156
Heat Rate (Btu/kWh average lifetime)	10,046	10,608
Planned outage rate	5.00%	5.00%
Forced outage rate	5.00%	5.00%

Operational expenditures

The EIA 2020 AEO provides the operational expenditures estimates for the nuclear-powered generation options in **Table 167**.

Table 167. Summary of nuclear-powered generating resource operating expenditures

Operational Expenditures, nuclear		
2019$	SMR	AP1000
Fixed O&M ($/kW-year)	$95	$122
Variable O&M ($/MWh)	$3	$2

Capital expenditures

EIA 2020 AEO research provides the basis for capital expenditure estimates in **Table 168**.

Table 168. Summary of nuclear-powered generating resource capital expenditures

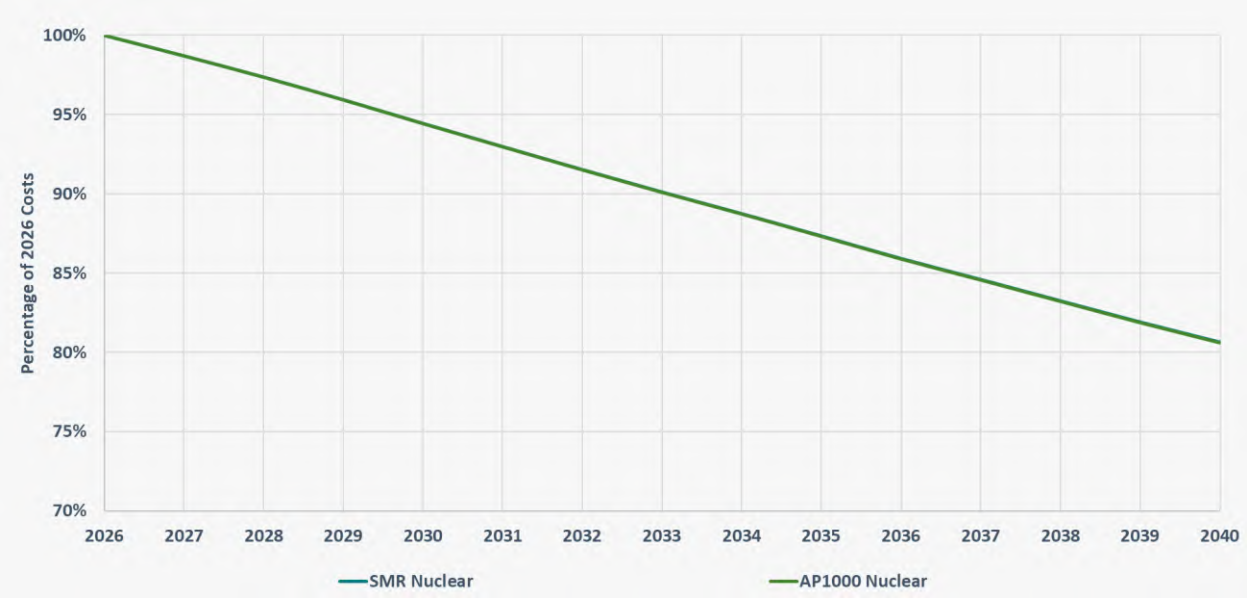
Capital Expenditures, nuclear		
2019 $/kW	SMR	AP1000
Overnight capital	$6,191	$6,041
Transmission Line Cost	$4	$1
Overnight EPC Capital Cost -Ex Interconnect Cost	$6,187	$6,040

Capital Expenditures, nuclear		
Location Adjustment	1.06	1.08
Location-adjusted Overnight Capital Cost	$6,579	$6,524

Forward capital cost curve

The EIA 2020 AEO projection of future capital costs for the Reference Case scenario are presented in **Figure 171**.

Figure 171. Nuclear-powered generator capital cost trajectory



M.5 Natural gas-fueled resources

M.5.1 Simple-cycle combustion turbine

Technology description

The simple-cycle combustion turbine (SCCT) is based on "one industrial frame Model F dual fuel CT in simple-cycle configuration with a nominal output of 237.2 MW gross. After deducting internal auxiliary power demand, the net output of the plant is 232.6 MW. The inlet air duct for the CT is equipped with an evaporative cooler to reduce the inlet air temperature in warmer seasons to increase the CT output. The CT is also equipped with burners designed to reduce the CT's NOX emission."[546] Selective catalytic reduction (SCR) and CO catalysts are not included.

Commercial status

Research in PGE's recent IRPs indicates that resources employing natural gas-fired combustion turbine generators are "well-proven and commercially available technologies for power generation."[547]

Operational characteristics

Table 169. Summary of SCCT operational characteristics

Operational characteristics	SCCT F-Class
Capacity (MW average lifetime)	227
Heat Rate (Btu/kWh average lifetime)	10,042
Planned outage rate	2.38%
Forced outage rate	1.73%

[546] EIA AEO 2020. "Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies." Prepared by Sargent & Lundy. Available at: https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf
[547] *Id.*

Operational expenditures

Fixed O&M includes the fixed portion of a long-term service agreement.

"Variable O&M costs include consumable commodities, such as water, lubricants, and chemicals. Also included is the average annual cost of the planned maintenance events for the CT over the long-term maintenance cycle. Planned maintenance costs for the CT in a given year are based on the number of equivalent starts the CT has accumulated. A significant overhaul is performed for this type of CT every 900 equivalent starts, and a major overhaul is performed every 2,400 equivalent starts. (CTs generally have two criteria to schedule overhauls: number of equivalent starts and number of [equivalent operating hours] EOH)."[548]

The SCCT is assumed to use a starts-based schedule, and the effective cost per start is shown in **Table 170** and included in the dispatch modeling for this resource.

Table 170. Summary of SCCT operational expenditures

Operational expenditures, SCCT	
2019 $	F-Class
Fixed O&M ($/kW-year)	$7
Variable O&M ($/MWh)	$1

Capital expenditures

EIA 2020 AEO research provides the basis for capital expenditure estimates, shown in **Table 171**.

Table 171. Summary of SCCT capital expenditures

Capital Expenditures, SCCT	
2019 $/kW	F-Class
Overnight capital	$713
Less: Transmission Line Cost	$5
Less: Gas Interconnection Cost	$19
Overnight EPC Capital Cost -Ex Interconnect Cost	$688

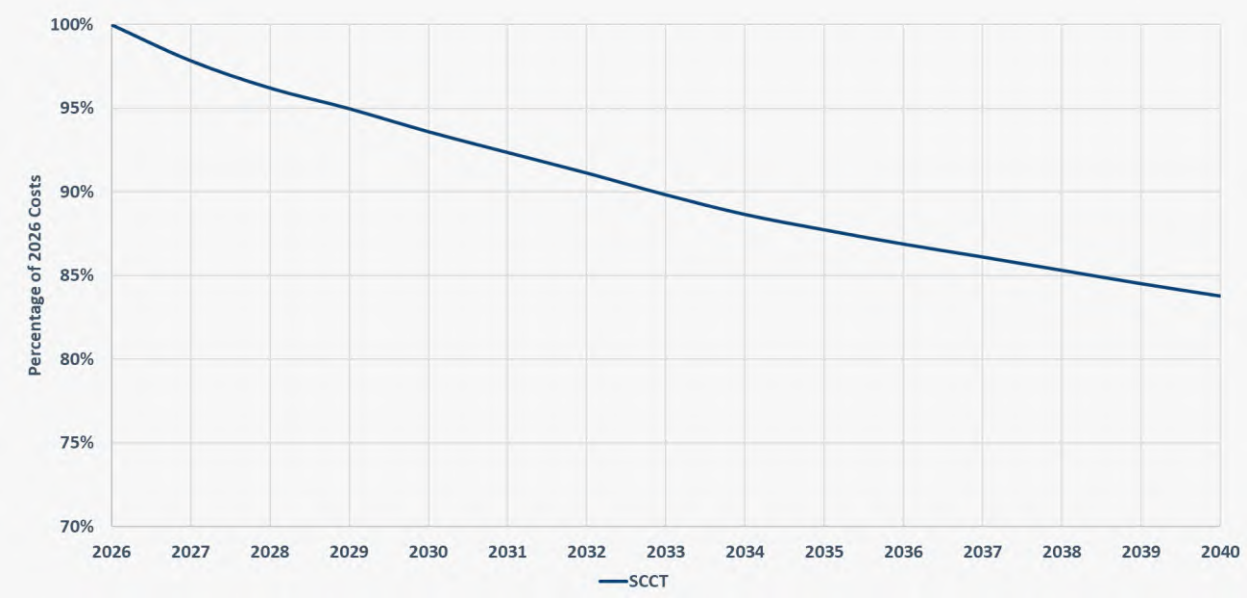
[548] *Id.*

Capital Expenditures, SCCT	
Location Adjustment	1.05
Location-adjusted Overnight Capital Cost	$721

Forward capital cost curve

The EIA AEO projection of future capital costs for the Reference Case scenario are presented in **Figure 172**.

Figure 172. Simple-cycle combustion turbine capital cost trajectory



M.5.2 Combined-cycle combustion turbine

Technology description

The combined-cycle combustion turbine (CCCT) resource comprises one Model H "advanced technology" combustion turbine (CT), one steam turbine generator (STG), and one electric generator that is common to the CT and the STG.

Emissions controls include burners to reduce NOX emissions, an SCR to reduce NOX emissions, and a CO catalyst to reduce CO emissions. "The inlet air duct for the CT is equipped with an evaporative cooler to reduce the inlet air temperature in warmer seasons to increase the CT and plant output…"

The CT is categorized as Model H industrial frame type CT with an advanced technology design since it incorporates in the design the following features:

- High-firing temperatures (~2900°F)
- Advanced materials of construction
- Advanced thermal barrier coatings"[549]

Commercial status

Research in PGE's recent IRPs indicates that resources employing natural gas-fired combustion turbine generators are "well-proven and commercially available technologies for power generation."

Operational characteristics

Table 172. Summary of CCCT operational characteristics

Operational characteristics	CCCT H-Class
Capacity (MW average lifetime)	407
Heat Rate (Btu/kWh average lifetime)	6,561
Planned outage rate	3.88%
Forced outage rate	2.19%

Operational expenditures

Fixed O&M includes the fixed portion of a long-term service agreement (**Table 173**).

"Variable O&M costs include consumable commodities such as water, lubricants, and chemicals and periodic costs to change out the SCR and CO catalysts. The variable O&M costs also include the average annual cost of the planned maintenance events for the CT and the STG over the long-term maintenance cycle. Planned maintenance costs for the CT in a given year are based on the number of EOHs the CT has run. A significant overhaul is typically performed for this type of CT every 25,000 EOH, and a major overhaul is performed

[549] *Id.*

every 50,000 EOH. (CTs generally have two criteria to schedule overhauls: number of equivalent starts and number of EOH)."[550]

The CCCT is assumed to require an EOH-based maintenance schedule for the CT. The STG requires less frequent major outage maintenance.

Table 173. Summary of CCCT operational expenditures

Operational Expenditures	CCCT
2019$	H-Class
Fixed O&M ($/kW-year)	$14
Variable O&M ($/MWh)	$3

Capital expenditures

EIA 2020 AEO research provides the basis for capital expenditure estimates (**Table 174**).

Table 174. Summary of CCCT capital expenditures

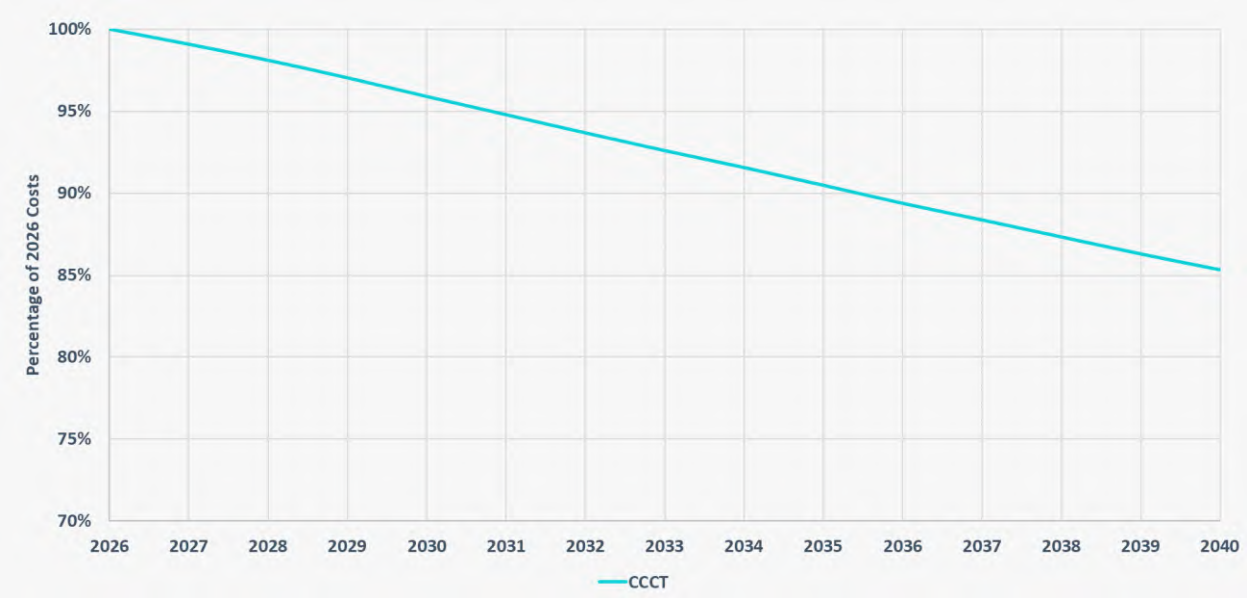
Capital expenditures	CCCT
2019 $/kW	H-Class
Overnight capital	$1,084
Transmission Line Cost	$4
Gas Interconnection Cost	$14
Overnight EPC Capital Cost -Ex Interconnect Cost	$1,066
Location Adjustment	1.08
Location-adjusted Overnight Capital Cost	$1,154

Forward capital cost curve

The EIA AEO projection of future capital costs for the Reference Case scenario are presented in **Figure 173**.

[550] *Id.*

Figure 173. Combined-cycle combustion turbine capital cost trajectory



M.5.3 Combined-cycle combustion turbine with CO_2 capture system

Technology description

The H-class combined-cycle unit is similar in configuration and specification to the traditional resource previously described. In addition to the CCCT, the resource includes an amine-based CO_2 capture system designed to remove 90 percent of the CO_2 from exhaust gases. The resource configuration as described in the EIA research include:

"[T]o obtain 90 percent CO_2 removal from the flue gas generated from the CT, [t]he full flue gas path must be treated. The flue gas generated from natural gas-fired CT combustions results in a much lower CO_2 concentration in the flue gas than flue gas from a coal-fired facility. As such, the flue gas absorber and quencher would be much larger in scale on a per ton of CO_2 treated basis than with a coal facility. However, the stripper and compression system would scale directly with the mass rate of CO_2 captured.

In this scenario, it is not practical to increase the CT or STG size to account for the steam extraction and added auxiliary power required by the CO_2 capture system. The net power output in the CO_2 capture case is significantly less than in Case 8.

The flue gas path differs from the base case (Case 8) in that 100 percent of the gas is directed to the carbon capture system downstream of the preheater section of the HRSG. The SCR and CO catalysts would operate the same, and the flue gas mass flows would be the same. Rather

than exiting a stack, the flue gases would be ducted to a set of booster fans that would feed the CO_2 absorber column. The total gross power generated from the CT is approximately the same as Case 8, with no carbon capture.

Steam for the CO_2 stripper is to be extracted from the intermediate-pressure turbine to the low-pressure turbine crossover line; however, the steam must be attemporated to meet the requirements of the carbon capture system. The total steam required for the carbon capture system is approximately 306,000 pounds per hour. As a result of the steam extraction, the gross STG generation outlet decreases from 133 MW to 112 MW."[551]

Commercial status

Research in PGE's recent IRPs indicates that resources employing natural gas-fired combustion turbine generators are "well-proven and commercially available technologies for power generation." Carbon capture and sequestration, however, has substantially fewer examples deployed in operation.

Operational characteristics

The CCCT described previously serves as the basis for this resource. The configuration and auxiliary power requirements for the operation of the CO_2 capture system, however, result in an approximately 40 MW decrease in the net capacity of this resource as described previously. Similarly, the resource is less efficient, resulting in a higher heat rate than the CCCT without CO_2 capture (**Table 175**).

Table 175. Summary of CCCT w/ CCS operational characteristics

Operational characteristics	CCCT w/ CCS
Capacity (MW average lifetime)	367
Heat Rate (Btu/kWh average lifetime)	7,271
Planned outage rate	3.88%
Forced outage rate	2.19%

[551] *Id.*

Operational expenditures

"Variable O&M costs include consumable commodities such as water, lubricants, chemicals, solvent makeup, and periodic costs to change out the SCR and CO catalysts. The variable O&M costs also include the average annual cost of the planned maintenance events for the CT and the STG over the long-term maintenance cycle. Planned maintenance costs for the CT in a given year are based on the number of EOHs the CT has run. A significant overhaul is typically performed for this type of CT every 25,000 EOH, and a major overhaul is performed every 50,000 EOH. (CTs generally have two criteria to schedule overhauls: number of equivalent starts and number of EOH)." The CCCT with CO_2 capture system is assumed to require an EOH-based maintenance schedule for the CT. The STG requires less frequent major outage maintenance.

"For the CO_2 capture system, variable costs include solvent makeup and disposal costs (usually offsite disposal; the spent solvent may be considered hazardous waste), additional wastewater treatment costs (predominantly CT blowdown treatment), and additional demineralized makeup water costs."[552]

The costs of CO_2 storage are not included in the EIA cost estimates; as such, these costs are derived from Hunter[553] to form a representative estimate of the total resource variable cost (**Table 176**).

Table 176. Summary of CCCT w/ CCS operational expenditures

Operational expenditures	CCCT w/ CCS
2019$	H-Class
Fixed O&M ($/kW-year)	$28
Variable O&M ($/MWh)	$6
Sequestration Cost ($/MWh)	$15
Total Variable O&M ($/MWh)	$21

[552] *Id.*
[553] Hunter et al., "Techno-economic analysis of long-duration energy storage and flexible power generation technologies to support high variable renewable energy grids." Retrieved from: https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3720769

Capital expenditures

EIA 2020 AEO research provides the basis for capital expenditure estimates, shown in **Table 177**.

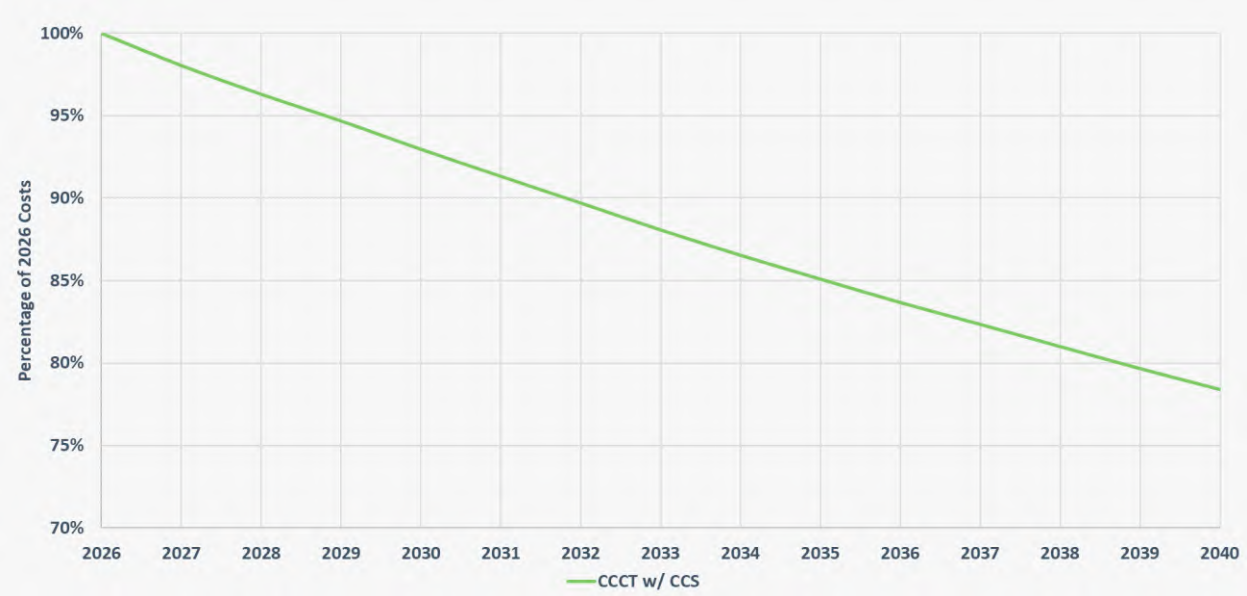
Table 177. Summary of CCCT w/ CCS capital expenditures

Capital expenditures	CCCT w/ CCS
2019 $/kW	H-Class
Overnight capital	$2,481
Transmission Line Cost	$5
Gas Interconnection Cost	$16
Overnight EPC Capital Cost -Ex Interconnect Cost	$2,461
Location Adjustment	1.08
Location-adjusted Overnight Capital Cost	$2,666

Forward capital cost curve

The EIA AEO projection of future capital costs for the Reference Case scenario are presented in **Figure 174**.

Figure 174. Combined-cycle combustion turbine w/ CCS capital cost trajectory



Appendix N. Renewable curtailment

As more variable energy resources are added to the system the amount of generation curtailed due to oversupply increases. This appendix discusses why oversupply happens and includes projections of future oversupply events.

N.1 Impact of resource curtailment

The addition of non-dispatchable intermittent resources in PGE's resource stack makes the balancing of demand and supply of energy increasingly complicated. These resources are primarily wind and solar, with hydropower uncertainty potentially adding to the complexity of committing the right resources at the right time leading. We define resource curtailment the result of regional surplus of wind and solar that cannot be balanced in other way than by shutting them down.

From PGE perspective, when wind is strong, hydropower is constrained to run at a given level, and solar generation is peaking, the combined output of such resources will be higher than PGE load. In this case, PGE will first attempt to:

- Sell surplus energy to the market
- Turn off thermal plants, if operationally possible, and/or fill storage, and/or minimize hydropower output if doable.

When both solutions are exhausted, the only option left is renewable curtailment, which is the partial or total shut down of the wind generation from one or more PGE wind and plants.

This section describes the impact of wind and solar curtailment on the value of such resources in the long-term. To estimate this effect, we used our WECC model, the same Aurora model used to forecast electricity prices in the PWN, as curtailment is triggered by regional imbalances. PGE estimated the monthly average generation curtailed for all wind and solar resources in Oregon and Washington under normal conditions and Reference Case prices. We did not identify which wind plant will be curtailed. We instead estimated how much is the expected overall curtailment for the whole wind and solar fleet in the entire PNW.

Using the WECC simulated resource output, we estimated curtailment as the difference between simulated generation and resource theoretical availability. We did this for all wind resources in Oregon and Washington, both existing and added by Wood Mackenzie to meet future load to 2043, both on-shore resources and off-shore. The result is that curtailment does and increasingly is projected to occur, especially in the Spring, when PNW wind, PNW hydropower, and WECC solar all maximize generation. **Table 178** shows the detail of simulated curtailment as percentage of maximum available monthly capacity for the future

RRRR, which represents normal condition, with reference gas prices and a California-like carbon cost. For each year and each month, the expected regional curtailment is color coded as follows: green, if there is no expected regional curtailment; yellow, when regional curtailment is expected; orange, when curtailment is significant; red, when regional curtailment is severe.

Table 178. Simulated wind curtailment in Oregon and Washington: RRRR future

Report Year/Month	1	2	3	4	5	6	7	8	9	10	11	12
2023	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2024	0%	0%	0%	0%	-1%	0%	0%	0%	0%	0%	0%	0%
2025	0%	0%	0%	-1%	0%	0%	0%	0%	0%	0%	0%	0%
2026	0%	0%	0%	0%	-1%	0%	0%	0%	0%	0%	0%	0%
2027	0%	0%	0%	0%	0%	-1%	0%	0%	0%	0%	0%	0%
2028	0%	0%	0%	-1%	-2%	-1%	0%	0%	0%	0%	0%	0%
2029	0%	0%	0%	-1%	-1%	-1%	0%	0%	0%	0%	0%	0%
2030	0%	0%	0%	-4%	-4%	-4%	-1%	0%	0%	0%	0%	0%
2031	0%	0%	0%	-5%	-7%	-6%	0%	0%	0%	0%	0%	0%
2032	0%	0%	0%	-7%	-18%	-9%	0%	0%	0%	0%	0%	0%
2033	0%	0%	0%	-8%	-9%	-10%	0%	0%	0%	0%	0%	0%
2034	0%	0%	0%	-10%	-15%	-18%	-2%	0%	0%	0%	0%	0%
2035	0%	0%	0%	-13%	-18%	-19%	0%	0%	0%	0%	0%	0%
2036	0%	0%	-1%	-29%	-52%	-62%	-4%	0%	0%	0%	0%	0%
2037	0%	0%	-1%	-29%	-57%	-67%	-3%	-1%	-3%	0%	0%	0%
2038	0%	0%	-5%	-37%	-76%	-79%	-9%	-1%	0%	-1%	0%	0%
2039	0%	0%	-4%	-38%	-69%	-78%	-11%	-1%	-1%	-1%	0%	0%
2040	0%	-1%	-4%	-42%	-79%	-88%	-14%	-1%	-1%	-2%	0%	0%
2041	0%	0%	-2%	-44%	-74%	-84%	-17%	-5%	-4%	-3%	0%	0%
2042	0%	0%	-7%	-50%	-83%	-92%	-26%	-8%	-3%	-2%	-1%	0%
2043	0%	0%	-6%	-52%	-79%	-83%	-30%	-5%	-6%	-3%	0%	0%

Short-term simulated wind curtailment is not significant under normal conditions, while starting in the mid-2030s it becomes much more so as more and more wind is added to the system. We used the same methodology to estimate solar curtailment in Oregon and

Washington and reported results in **Table 179**. In our model, solar curtailment is not significantly impacting generation until the 2040s. This is the result of less capacity installed in the PNW and the Wood Mackenzie modeling choice of having wind curtail before solar. This means that solar plants are curtailed only after all wind is offline (a modeling simplification). Any actual curtailment will depend on operational constraints and financial considerations.

Table 179. Simulated solar curtailment in Oregon and Washington: RRRR future

Report Year/Month	1	2	3	4	5	6	7	8	9	10	11	12
2023	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2024	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2025	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2026	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2027	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2028	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2029	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2030	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2031	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2032	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2033	0%	0%	0%	0%	-1%	0%	0%	0%	0%	0%	0%	0%
2034	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2035	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2036	0%	0%	0%	0%	0%	-2%	-2%	0%	0%	0%	0%	0%
2037	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2038	0%	0%	0%	0%	0%	-4%	-6%	0%	0%	0%	0%	0%
2039	0%	0%	0%	0%	0%	-1%	-4%	0%	0%	0%	0%	0%
2040	0%	0%	0%	0%	0%	-5%	-5%	0%	0%	0%	0%	0%
2041	0%	0%	0%	0%	-1%	-4%	-4%	0%	0%	0%	0%	0%
2042	0%	0%	0%	0%	0%	-8%	-9%	0%	0%	0%	0%	0%
2043	0%	0%	0%	0%	-1%	-3%	-11%	0%	0%	0%	0%	0%

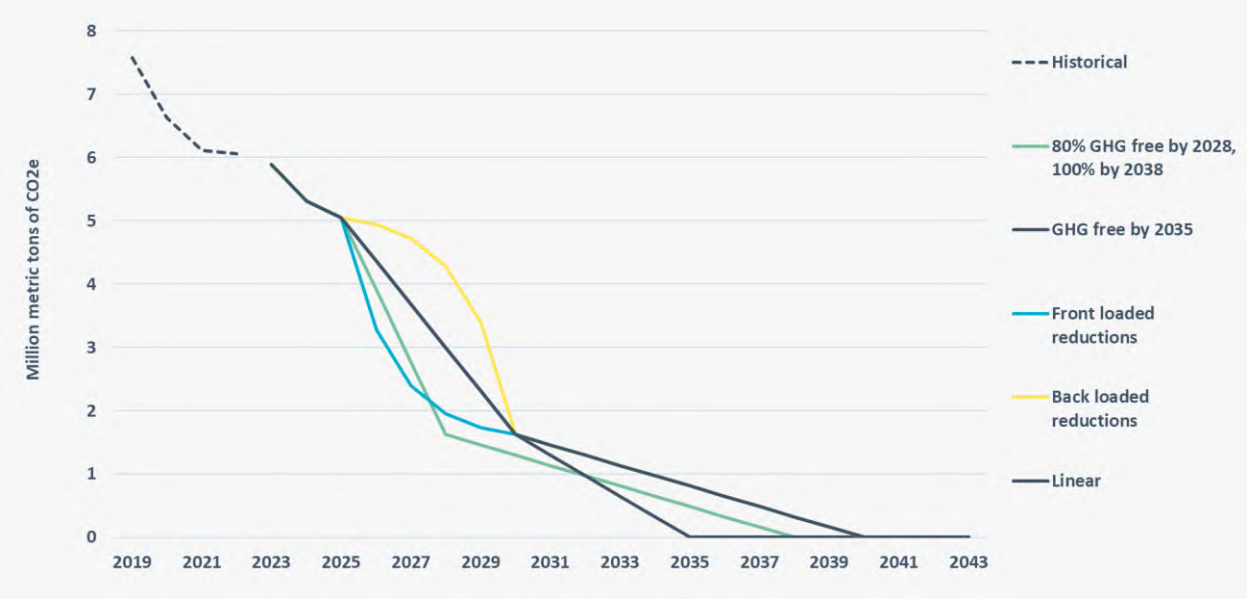
Appendix O. Thermal Operations/ Output

This appendix provides a graphical overview of PGE's projected retail GHG emissions, emissions and generation by fuel type, heat rate projections by fuel type, and a look at GHG emissions by unit under three different GHG glidepaths.

O.1 PGE GHG emitting resources

PGEs historical retail emissions from 2019 to 2021, as well as IRP forecasts for retail GHG emissions from 2023 to 2043, are shown below in **Figure 175.** The forecast includes five different GHG glidepaths, linear, front loaded (more GHG reductions early), back loaded (more GHG reductions later), GHG free by 2035, and achieving HB 2021 goals two years early.

Figure 175. Annual historical and projected GHG emissions for retail load service



The following graphs (**Figure 176** and **Figure 177**) show total annual GHG emissions and energy generated and purchased by fuel type for resources in the Preferred Portfolio.[554] Power plant Boardman, which retired in 2020, is in the historical values. Total generation and emissions represent both retail load service and wholesale sales.

[554] Waste represents a bilateral landfill contract.

Figure 176. Historical and projected total generation and purchases by fuel type from emitting sources

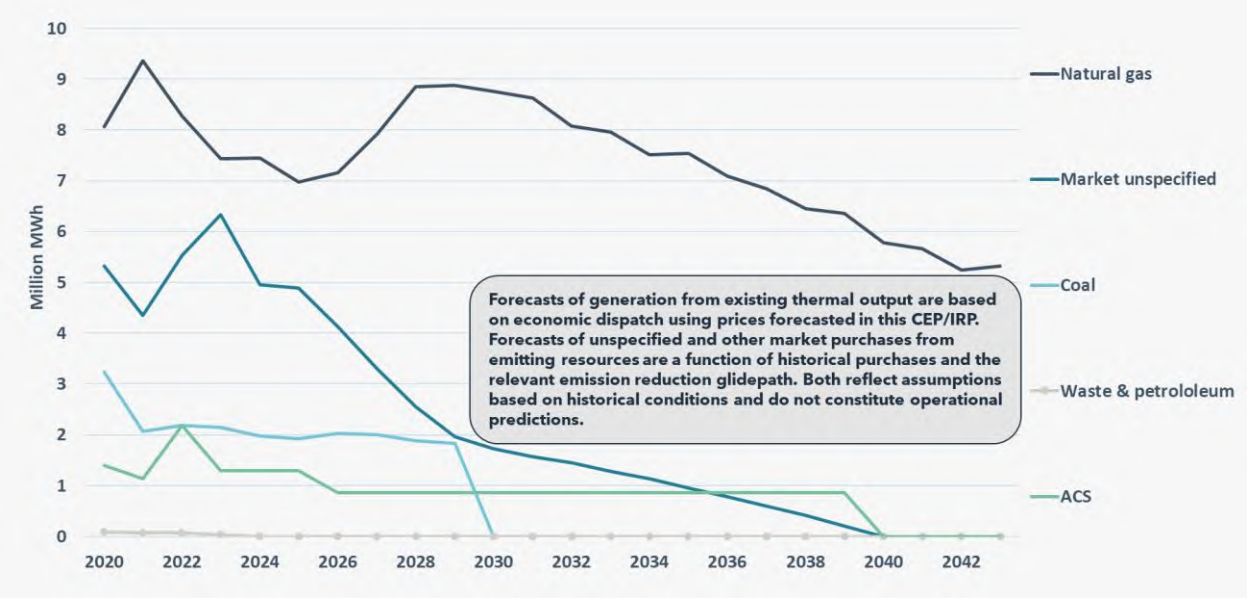
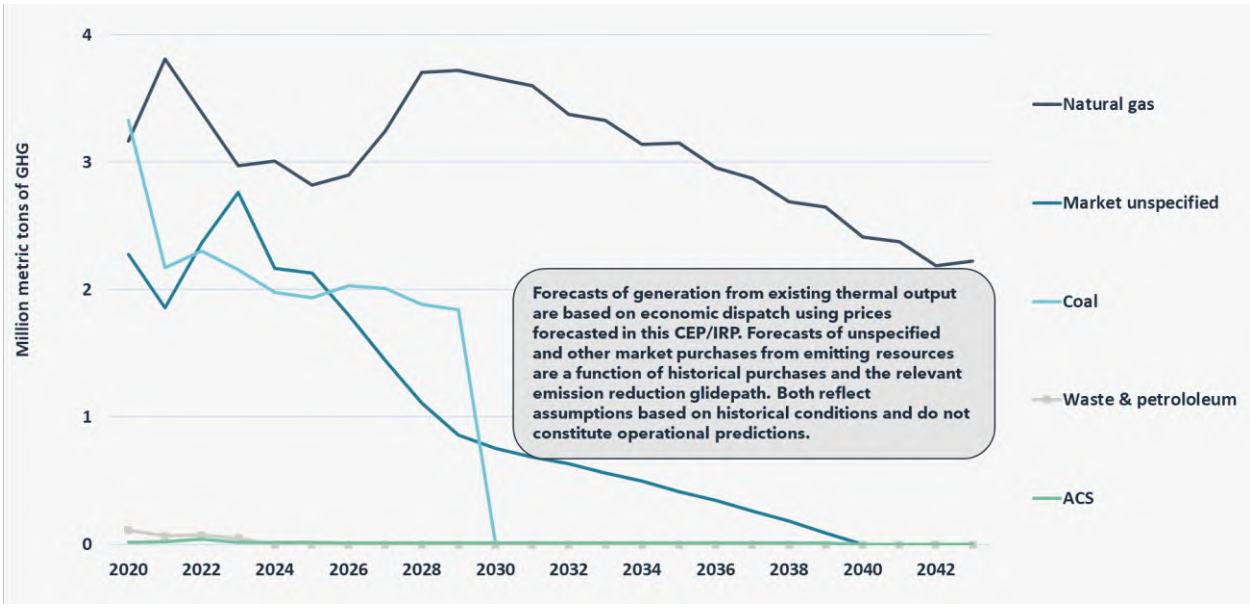


Figure 177. Historical and projected total GHG emissions by fuel type



The following graphs (**Figure 178** and **Figure 179**) show annual GHG emissions and energy generated and purchased by fuel type for resources in the Preferred Portfolio used to serve retail load (power plant Boardman, which retired in 2020, is in the historical values).

Figure 178. Historical and projected retail generation and purchases by fuel type from emitting sources

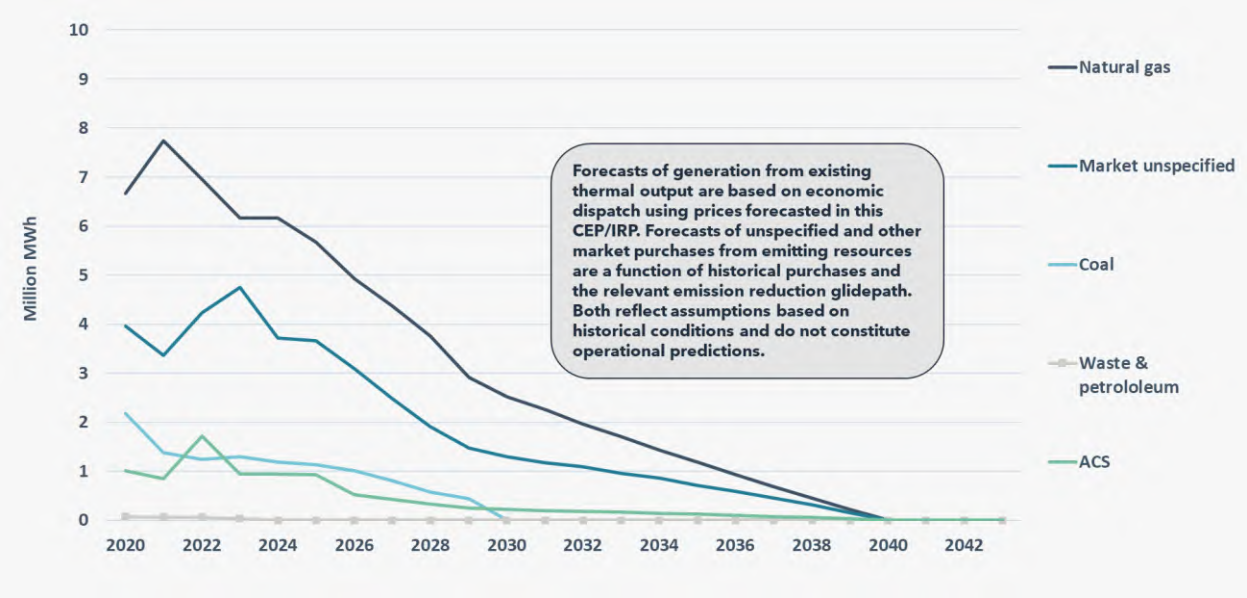
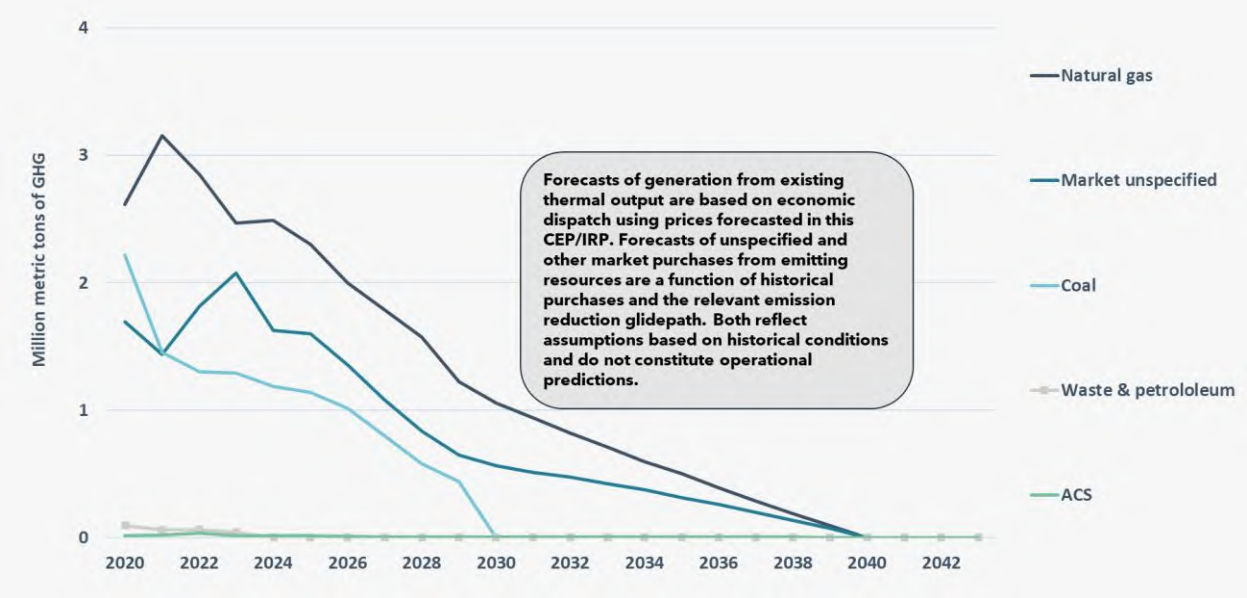


Figure 179. Historical and projected retail GHG emissions by fuel type



The following graph (**Figure 180**) shows the annual weighted average heat rate by fuel type for resources in the Preferred Portfolio. Individual plant heat rates in the forecasted data are static and based on Oregon Department of Environmental Quality (ODEQ) CO2e intensity values for future years. The future variations in weighted average heat rate are due to annual changes in forecasted economic dispatch. Due to a lack of knowledge of the underlying fuel source market purchase heat rates are not included.

Figure 180. Historical and projected annual weighted average heat rate by fuel

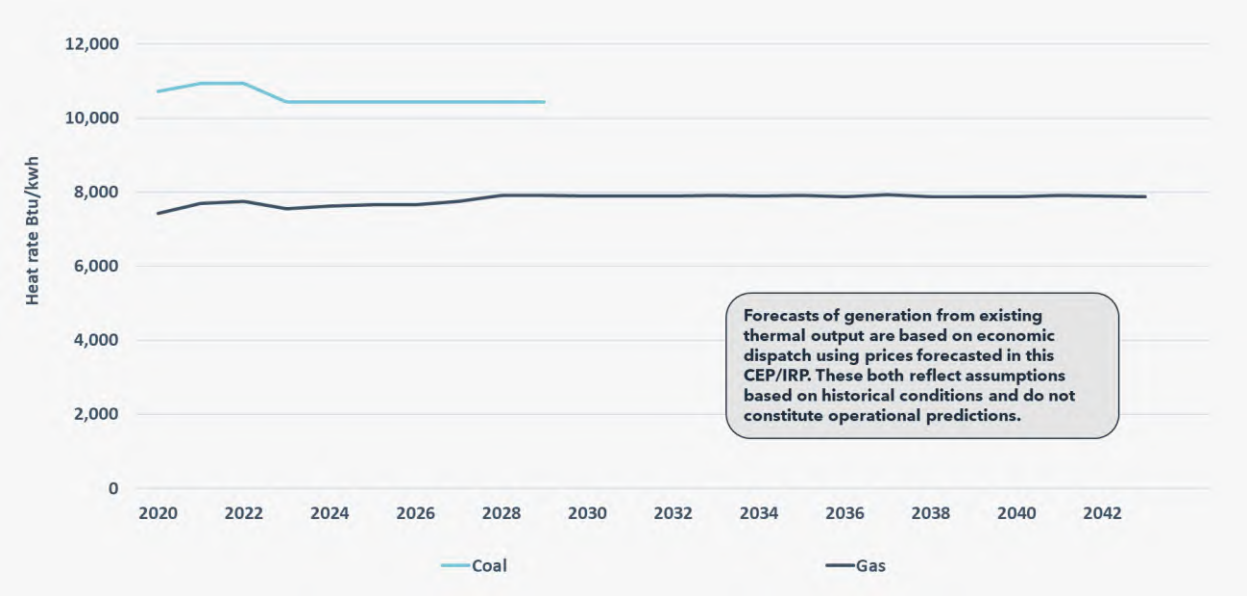


Figure 181-Figure 182 reflect GHG emissions from generation and purchases under three decarbonization glidepaths. The lines specific to individual resources show retail GHG emissions. The wholesale sales category captures GHG emissions from sales from all sources (these are additional to the retail GHG emissions).

Figure 181. Total (retail + wholesale) GHG emissions under a linear reduction glidepath (Reference Case)[555]

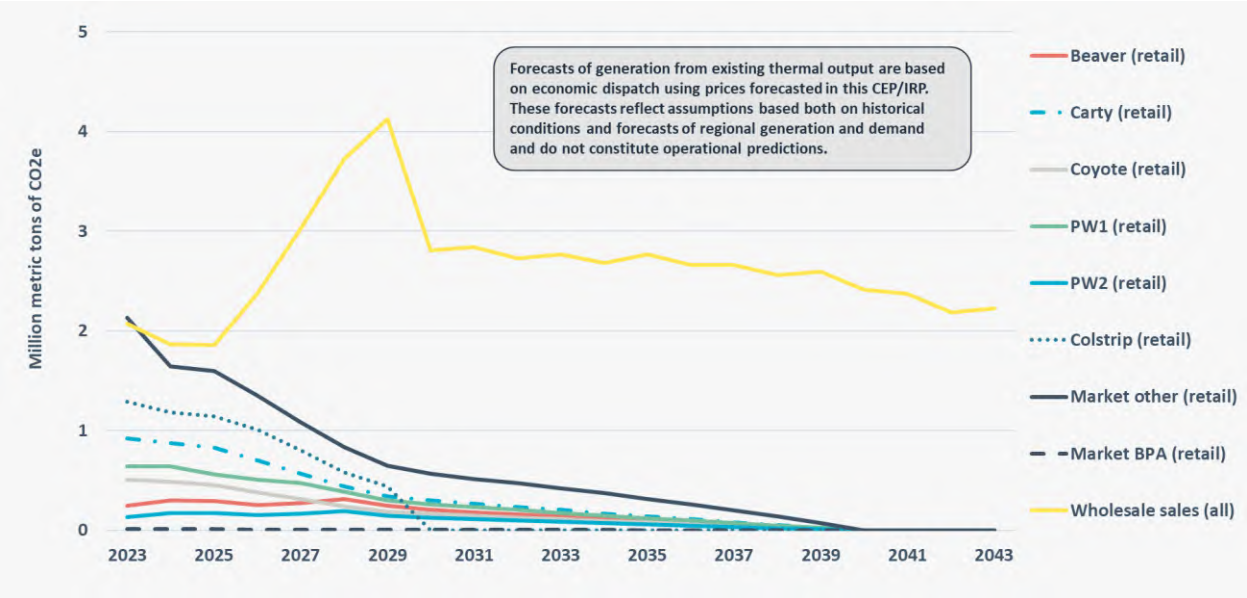


Figure 182. Total (retail + wholesale) GHG emissions under a front-loaded reduction glidepath (Reference Case)

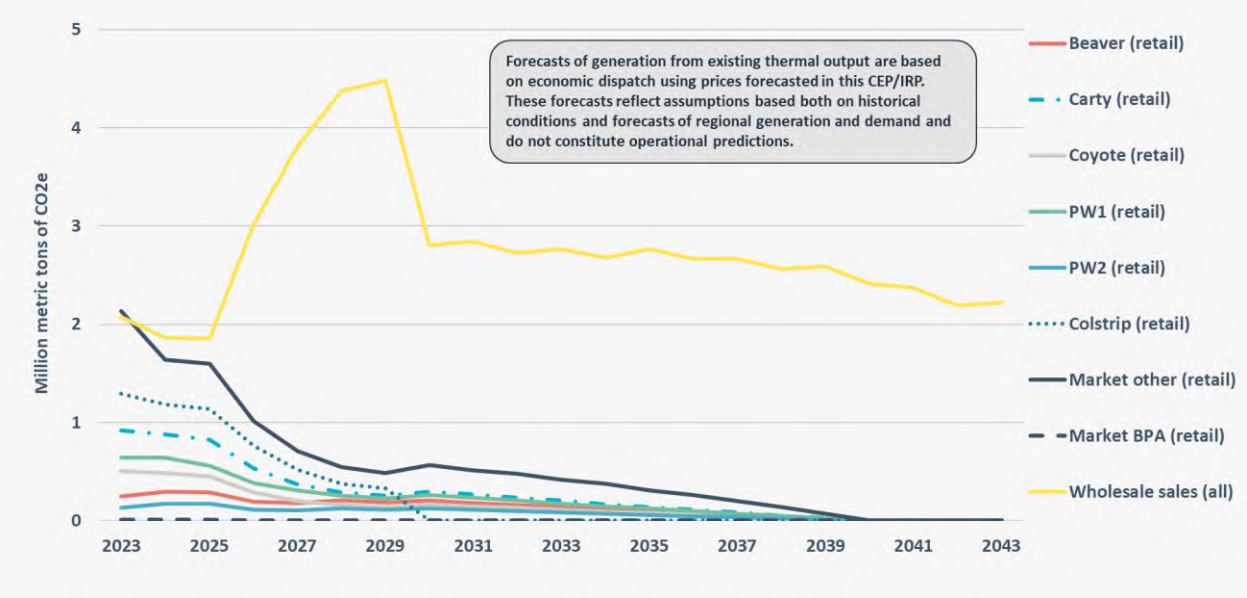
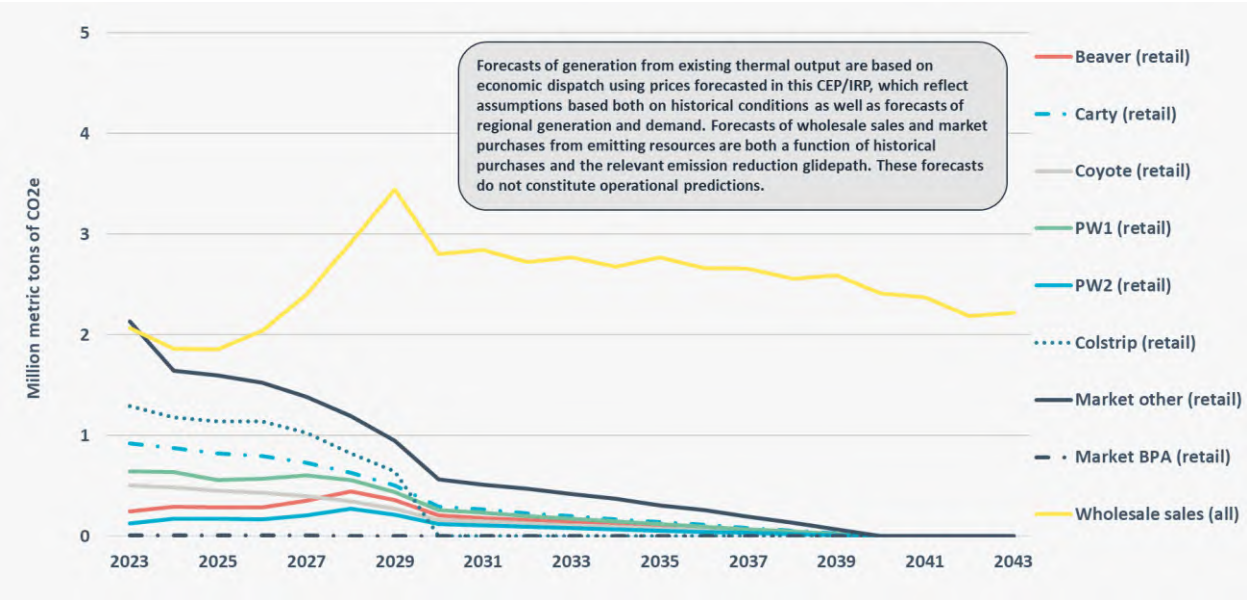


Figure 183. Total (retail + wholesale) GHG emissions under a back-loaded reduction glidepath (Reference Case)



Appendix P. Acronyms

Acronym	Agency/Entity/Term
AC	Alternating Current
ACS	Asset Controlling Supplier
ADF	Augmented Dickey Fuller tests
AEO	Annual Energy Outlook
AI	Artificial Intelligence
aMW	Average Megawatt
ANSI	American National Standards Institute
ARIMA	Autoregressive Integrated Moving Average
ART	Annual Revenue-requirement Tool
ASCC	Associated System Capacity Contribution
ASCE	American Society of Civil Engineers
ATB	Annual Technology Baseline
ATC	Available Transfer Capacity
AUT	Annual Update Tariff
B2H	Boardman to Hemingway
BAA	Balancing Authority Area
BABGI	Building A Better Grid Initiative
BCEM	Business Continuity and Emergency Management Team

Acronym	Agency/Entity/Term
BE	Building Electrification
BES	Bulk Electric System
BESS	Battery Energy Storage System
BFB	Bubbling Fluidized Bed
BIPOC	Black, Indigenous and People of Color
BLS	Bureau of Labor Statistics
BOEM	Bureau of Ocean Energy Management
BOP	Balance of Plant
BPA	Bonneville Power Administration
BPSC	Beaverton Public Safety Center
BTU	British Thermal Units
CA	California
CAA	Community Action Agencies
CAGR	Compounded Annual Growth Rates
CAISO	California Independent System Operator
CARB	California Air Resources Board
CBI	Community Benefit Indicator

Acronym	Agency/Entity/Term
CBIAG	Community Benefits and Impacts Advisory Group
CBO	Community-Based Organization
CBRE	Community-based Renewable Energy
CCCT	Combined-Cycle Combustion Turbine
CCS	Carbon Capture Sequestration
CCUS	Carbon Capture, Utilization and Storage
CDD	Cooling Degree Days
CEAE	Canadian Entitlement Allocation Extension
CEC	California Energy Commission
CELID	Customers Experiencing Long Interruption Duration
CEMI	Customers Experiencing Multiple Interruptions
CEP	Clean Energy Plan
CETA	Washington's Clean Energy Transformation Act
CF	Conditional Firm
CF200	Conditional Firm 200hr Transmission
CHIPS	Creating Helpful Incentives to Produce Semiconductors and Science Act
CHP	Combined Heat and Power
CIFIA	Carbon Dioxide Transportation Infrastructure Finance and Innovation Program
CO	Colorado
CO2	Carbon Dioxide
CO2e	Emissions of Carbon Dioxide Equivalent
COD	Commercial Operation Date
COP	Construction and Operations Plan
COS	Cost of Service
CPP	Climate Protection Program
CPUC	California Public Utilities Commission
CSO	Community-Serving Organization
CSPV	Crystalline Silicon Photovoltaic
CT	Combustion Turbine
CTWS	Confederated Tribes of Warm Springs
DAC	Direct Air Capture
DC	Direct Current
DEI	Diversity, Equity and Inclusion
DEQ	Department of Environmental Quality
DER	Distributed Energy Resources
DG	Distributed Generation

Acronym	Agency/Entity/Term
DOE	Department of Energy
DOGAMI	Department of Geology and Mineral Industries
DR	Demand Response
DSG	Dispatchable Standby Generation
DSP	Distribution System Plan
E3	Energy and Environmental Economics, Inc.
EDAM	Energy Day-Ahead Market
EE	Energy Efficiency
EFSC	Energy Facility Siting Council
EGS	Enhanced Geothermal Systems
EIA	Energy Information Administration
EIM	Energy Imbalance Market
EIR	Electric Industry Registry
EJ	Environmental Justice
ELCC	Effective Load Carrying Capability
EQC	Environmental Quality Commission
EO	Executive Order
EOH	Equivalent Operating Hours
EPRI	Electric Power Research Institute
ESG	Environmental, Social and Governance
ESSs	Electricity Service Suppliers
ETO	Energy Trust of Oregon
EV	Electric Vehicle
FEMA	Federal Emergency Management Agency
FERC	Federal Energy Regulatory Commission
GDP	Gross Domestic Product
GFI	Green Future Impact
GHG	Greenhouse Gases
GMLC	Grid Modernization Laboratory Consortium
GRC	General Rate Case
GW	Gigawatt
H2	Hydrogen Gas
HB	House Bill
HDD	Heating Degree Days
HFRZs	High Fire Risk Zones
HLH	Heavy Load Hour
iCBI	Informational Community Benefits Indicator
IE	Independent Evaluator
IEEE	Institute of Electrical and Electronics Engineers
IEPR	Integrated Energy Policy Report
IIJA	Infrastructure, Investment, and Jobs Act
ILR	Inverter Load Ratio

Acronym	Agency/Entity/Term
IO	Immediate Occupancy
IOC	Integrated Operations Center
IOU	Investor-owned Utilities
IPC	Idaho Power Company
IPCC	Intergovernmental Panel on Climate Change
IQBD	Income Qualified Bill Discount
IRA	Inflation Reduction Act
IRP	Integrated Resource Plan
ISO	Independent System Operator
ITC	Investment Tax Credits
KPSS	Kwiatkowski, Phillips, Schmidt, and Shin tests
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt-hour
L&R	Load and Resource
LBNL	Laurence Berkeley National Laboratory
LC	Least Cost
LCOE	Levelized Cost of Wind Energy
LDS/LDES	Long-Duration Energy Storage
LGIP	Large Generator Interconnection Process

Acronym	Agency/Entity/Term
LIHEAP	Low-Income Home Energy Assistance Program
LLC	Limited Liability Company
LLH	Light Load Hour
LNG	Liquefied Natural Gas
LOLE	Loss of Load Expectation
LOLH	Loss of Load Hours
LRB	Load Resource Balance
LUCAS	Levelized Utility Cost Aggregator System
LTDA	Long-term Direct Access
LTF	Long-term Firm
MACRS	Modified Accelerated Cost Recovery System
MAIFI	Momentary Average Interruption Frequency Index
MCE	Maximum Credible Earthquake
MED	Major Event Days
MEP	Market Energy Position
Mid-C	Mid-Columbia
Min Avg LT Cost	Minimizing Average Long-term NPVRR
Min Avg ST cost	Minimizing Average Short-term NPVRR
Min Ref ST cost	Minimizing Reference Case Short-term NPVRR
MMBtu	1 Million British Thermal Units

Acronym	Agency/Entity/Term
MMT	Million Metric Tons
MT	Montana
MW	Megawatt
MWa	Megawatt Average
MWac	Megawatt of Alternating Current
MWh	Megawatt-hour
MYP	Multiyear Flexible Load Plan Aka Multi-year Plan
NARUC	National Association of Regulatory Utility Commissions
NASEO	National Association of State Energy Officials
NCE	Non-cost-effective
NEM	Net Energy Metering
NERC	North American Electric Reliability Corporation
NESP	National Energy Screening Project
Net CONE	Net Cost of New Entry
NG	Natural Gas
NITS	Network Integration Transmission Services
NLDA	New Load Direct Access
NM	New Mexico
NOPR	Notice of Open Rulemaking
NPVRR	Net Present Value Revenue Requirement

Acronym	Agency/Entity/Term
NREL	National Renewable Energy Laboratory
NSRDB	National Solar Radiation Database
NTIA	National Telecommunication and Information Administration
NV	Nevada
NWACI	Northwest AC Intertie
NWMT BA	NorthWestern Corporation Balancing Authority
NWS	Non-wires Solutions
O & M	Operations & Maintenance
OAR	Oregon Administrative Rules
OATT	Open Access Transmission Tariff
OCBs	Oil Circuit Breakers
ODOC	Oregon Department of Commerce
OCEWC	Oregon Clean Energy Workforce Coalition
OCS	Outer Continental Shelf
ODEQ	Oregon Department of Environmental Quality
ODOE	Oregon Department of Energy
ODOT	Oregon Department of Transportation
OEQC	Oregon Environmental Quality Commission

Acronym	Agency/Entity/Term
OFA	Over Fire Air
OHA	Oregon Health Authority
OHCS	Oregon Housing and Community Services
OPUC	Oregon Public Utility Commission
OR	Oregon
ORS	Oregon Revised Statutes
OSU	Oregon State University
PACW	PacifiCorp West
PCAM	Power Cost Adjustment Mechanism
pCBI	Portfolio Community Benefit Indicator
PG&E	Pacific Gas & Electric
PGE	Portland General Electric
PGEM	PGE Merchant
PGET	PGE Transmission System
PNUCC	Pacific Northwest Utilities Conference Committee
PNW	Pacific Northwest
POD	Point of Delivery
POI	Point of Interconnect
POR	Point of Receipt
PPA	Power Purchase Agreement
PRM	Planning Reserve Model
PSH	Pumped Storage Hydro
PSPS	Public Safety Power Shutoff
PTC	Production Tax Credit
PTP	Point-to-Point
PUC	Public Utility Commission
PUD	Public Utility District
PUMS	Public Use Microdata Sample
PV	Photovoltaic
PZM	PGE Zone Model
QF	Qualifying Facilities
rCBI	Resource Community Benefit Indicator
R&D	Research and Development
RC	Reliability Coordinator
RCP	Representation Concentration Pathway
RDPO	Regional Disaster Preparedness Organization
REC	Renewable Energy Certificates
RFP	Request for Proposals
RMJOC	River Management Joint Operating Committee
RNG	Renewable Natural Gas
ROSE-E	Resource Optimization Strategy Engine
ROW	Rights-of-Way
RPS	Renewable Portfolio Standard
RTO	Regional Transmission Organization

Acronym	Agency/Entity/Term
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SALMON	Smart Grid Advanced Load Management & Optimized Neighborhoods
SAM	System Advisor Model
SAP	Site Assessment Plan
SB	Senate Bill
SC-CO2	Supercritical Carbon Dioxide
SCCT	Simple-Cycle Combustion Turbine
SCR	Selective Catalytic Reduction
SE	Southeast
SEC	Securities and Exchange Commission
SGTB	Smart Grid Test Bed
SMR	Small Modular Reactor
SoA	South of Allston
SPP	Southwest Power Pool
SSPC	Salem Smart Power Center
STDA	Standard-term Direct Access
STEP	Strategic Tribal Engagement Plan
STG	Steam Turbine Generator
T&D	Transmission and Distribution
TE	Transportation Electrification
TEP	Transportation Electrification Plan
TRC	Total Resource Cost
TSR	Transmission Service Request
TSEP	TSR Study and Expansion Process
TTC	Total Transfer Capability
Tx	Transmission
UAMPS	Utah Associated Municipal Power Systems
UGB	Urban Growth Boundary
UM	Utility Matter
URM	Unreinforced Masonry
US	United States
US DOC	United States Department of Commerce
US DOE	US Department of Energy
US DOEE	US DOE & Environment
US EPA	United States Environmental Protection Agency
VER	Variable Energy Resources
VAR	Value at Risk
VOS	Value of Service
VPP	Virtual Power Plant
WA	Washington
WAP	Low Income Weatherization Assistance Program

Acronym	Agency/Entity/Term
WECC	Western Electricity Coordinating Council
WIND	Wind Integration National Database
WM	Wood Mackenzie (consultancy)
WMP	Wildfire Mitigation Plan
WOCS	West of Cross Cascades South
WPP	Western Power Pool
WRAP	Western Resource Adequacy Program
WX T&TA	Weatherization Training and Technical Assistance
WY	Wyoming

External Studies

Ext. Study-I. Deep decarbonization

In 2021, Portland General Electric commissioned Evolved Energy Research (EER) to conduct an independent study exploring pathways to deep decarbonization for its service territory, called a Deep Decarb Study. This study was finished in 2022 and is an update to an earlier Deep Decarb Study that accompanied the 2019 IRP. The Deep Decarb Study explores potential pathways for economy-wide decarbonization across PGE's service territory given the enactment of House Bill 2021 and DEQ's Climate Protection Program emissions targets. The study does not replace existing tools or processes used by PGE to plan for resource and system needs in compliance with the law.

This analysis was completed prior to the passage of the Inflation Adjustment Act. To adjust for the impact of the IAA on PGE and our customers, an additional slide by PGE has been added to the study.

Information about the deep decarbonization study and study update can be found on our website at https://portlandgeneral.com/2022-deep-decarb-study.

Ext. Study–II. EE methodology

PGE relies on the Energy Trust to identify energy efficiency measures available in the IRP. Energy Trust is a nonprofit organization funded by Oregon and Southwest Washington utility customers. Using a resource assessment modeling tool they identify what energy efficiency measures are cost-effective for PGE. These cost-effective measures are built into the IRP load forecast and assumed to be acquired in most portfolios. Energy Trust also provide measures they deem to be non-cost effective to PGE. Non-cost-effective measures are screened for current cost-effectiveness a second time using IRP models.

Information about the deep decarbonization study and study update can be found on our website at https://portlandgeneral.com/2023-energy-efficiency-resource-assessment-model.

Ext. Study-III. Climate adaptation

PGE contracted with Creative Renewable Solutions to study the impact of climate change on PGE's loads and resources. The study was requested by stakeholders and PUC Staff as part of the 2019 IRP acknowledgement process. It cumulates in a list of recommendations PGE can incorporate to better address climate change in long term planning. Based on the recommendations and discussions with the consultancy, PGE reduced the number of hydro and temperature years used in long term planning adequacy models to better align with the changing climate. The study also provided data, via the RMJOC, on how hydropower generation may change due to climate change. Using these data, PGE ran multiple sensitivities assessing how different future hydro conditions impact resource adequacy. PGE will take Creative Renewable Solutions recommendations into consideration for future planning work.

Information about the climate adaptation study can be found on our website at https://portlandgeneral.com/pge-climate-change-resource-planning-study.

Video archive can be found at https://www.youtube.com/watch?v=SOT69jGpiv0&t=7618s

Presentation slides at https://assets.ctfassets.net/416ywc1laqmd/3Bv5b1kzoD9flvapvcpBrA/981ab90a5ef126db416dd0567a6b5bd5/IRP_Roundtable_October_22-9_V2.pdf#page=21

Ext. Study–IV. Flexibility study

PGE worked with Blue Marble Analytics to study system flexibility needs. This study builds off the 2019 IRP flexibility study also conducted by Blue Marble. It uses a production-cost model, GridPath, to examine the PGE system under various commitment stages (day-ahead, hour-ahead, real time). It focuses on three items: flexibility adequacy, flexibility integration cost of new resources, and new resource (like batteries) flexibility value.

Information about the deep decarbonization study and study update can be found on our website at https://portlandgeneral.com/flexibility-studies.

Attachment 3. Energy GPS Load Resource Balance Report

Western Oregon Supply Demand Forecast

Prepared for

Cascade Renewable Transmission, LLC

Prepared by

Energy GPS Consulting (EGPSC), LLC

1/7/2025

ENERGYGPS CONSULTING LLC

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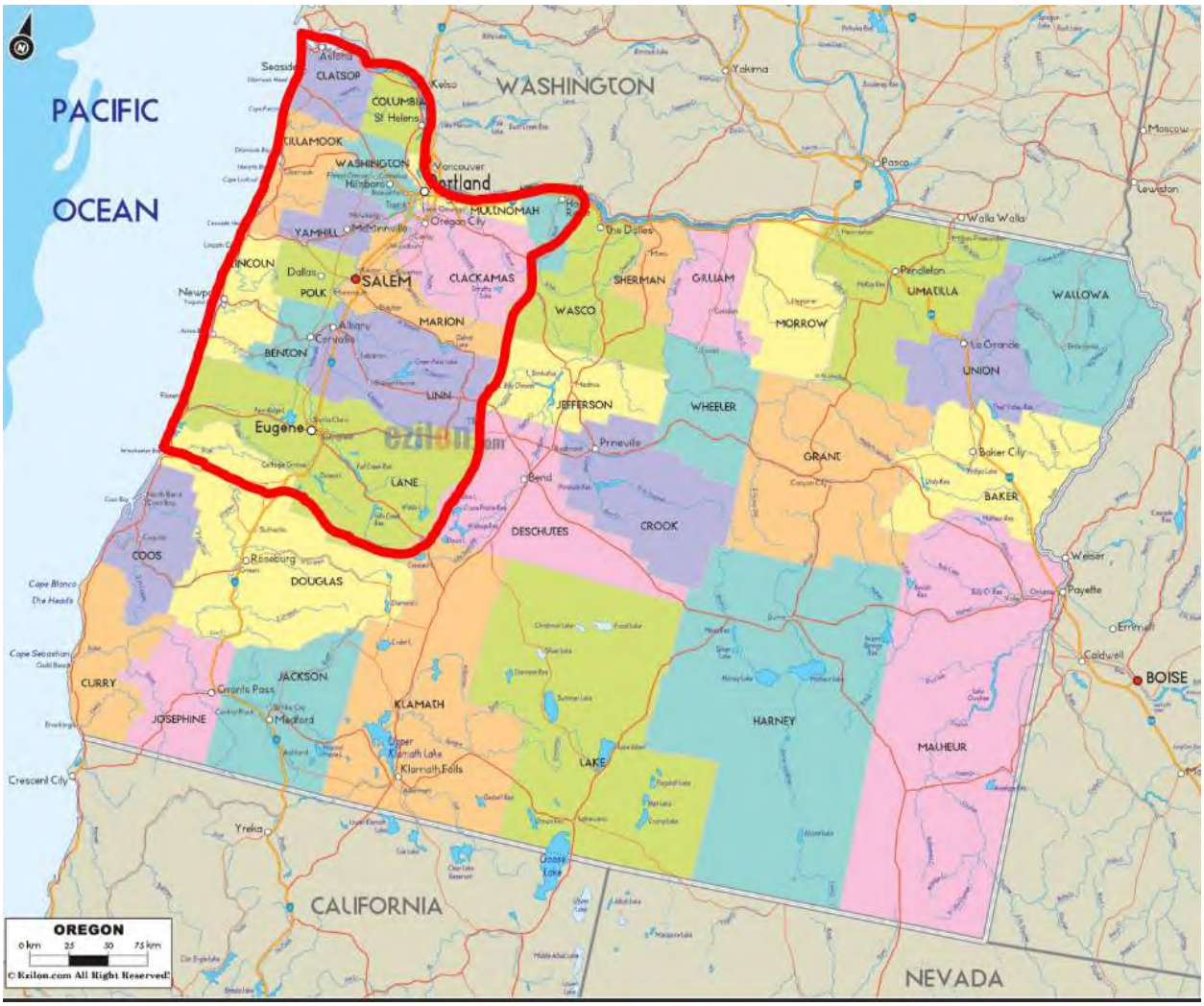
Executive Summary

Cascade Renewable Transmission, LLC (CRT) proposes to develop and construct a 1,100 MW underground and underwater transmission line between The Dalles and Portland, OR (Project) for the purpose of enhancing transmission transfer capability of the West of Cascades – South (WOCS) Transmission Path[1], while bypassing the constrained South of Allston ("SOA") and North of Pearl ("NOPE") flowgates. The Project is scheduled to become operational in the 2029-2030 timeframe. As part of the permitting process, and to determine the reliability need for incremental transmission, CRT requested Energy GPS Consulting LLC (EGPSC, we, us, our) to prepare a supply and demand balance forecast for Western Oregon from 2025 to 2045.



[1] The WOCS Transmission Path, or Path 5, is a major east-west high voltage transmission intertie path from east of the Cascades into the Portland area within the Western Electricity Coordinating Council (WECC), currently with a maximum transfer limit of 7,600 MW in the winter and 5,930 MW in the summer.

We used data from publicly available sources to forecast the capacity requirements for western Oregon (OR) including the peak load, transmission losses, and reserve margin of Portland General Electric (PGE), the western OR portion of Bonneville Power Administration (BPA), and the western OR portion of PacifiCorp West (PACW). In addition, we forecasted the supply in these areas based on estimates of firm generating capacity and firm transmission imports. The supply/demand balance for the region was calculated as required capacity less firm supply and expressed in MW.

We found that the western OR region has surplus capacity in the next two years from 2025 and 2026. In 2027 our forecast shows the region is short capacity. This capacity shortage is estimated at 149 MW in 2027 and increases to over 2.3 GW in 2035. This large capacity shortage is driven by increasing peak load without corresponding increasing local generating capacity west of the cascades or increasing firm transmission on the two major transmission constraints (i.e., WOCS and SOA)[2].

Our study clearly demonstrates a firm capacity need for system reliability in western OR by 2030. Our assumptions were conservative reflecting current estimates of peak load and peak load growth in the region, and generous firm capacity assumptions of hydro resources as compared to historical performance. In our opinion, the region is likely to see higher load growth rates due to structural demand changes (e.g., in home air conditioning), electrification of the transportation sector, and increased industrial load from manufacturing and data centers. Such a scenario would therefore increase the supply deficit as compared to the forecast presented in this report.

[2] The North of Pearl flowgate is another constrained transmission flowgate recently announced by BPA. This flowgate can restrict flows into the heart of PGE's service territory in West Portland. For our analysis, we have assumed the WOCS is the limiting constraint.

Background

Energy GPS Consulting (EGPSC) was retained by Cascade Renewable Transmission, LLC (CRT) to develop a supply-demand balance forecast for a portion of western Oregon in and around Portland, OR. The purpose of the supply-demand balance is to determine if the analyzed region is short or long in capacity. We used data from publicly available sources to forecast peak load, transmission losses, reserve margin requirements, firm generating capacity, and firm transmission imports from 2025 to 2045. We included parameters and made input assumptions consistent with the Demonstration of Need requirements as defined in the Oregon System Reliability Rule. This included forecasting a 1 in 20-year peak load and transmission losses. This report details our specific approach to forecasting the supply demand balance and the results of the forecast.

Approach

To quantify the supply demand balance, we first identified the study area for the forecast (See Figure 1), we then determined the capacity requirement in MW for this region. Next, we determined the firm supply in the region. Finally, we calculated the difference between supply and demand to determine firm capacity shortfall or surplus each year. Each part of this approach is described in further detail below.

Study region

The study region we selected is western Oregon, specifically, the service areas of Portland General Electric, a portion of Bonneville Power Administration, and a portion PacifiCorp West. The major load centers in this area are the City of Portland and the I5 corridor from Portland to Eugene. The transmission constraints for importing power into this area are the cross cascades south transmission constraint and the South of Allston transmission constraint[3].

Capacity requirement

The amount of firm capacity required to maintain reliability in a system is calculated as the peak load plus transmission losses and a planning reserve margin (PRM). Transmission losses were estimated at 8% of total peak load based on Idaho Power's 2017 IRP. The PRM was estimated at 16% of the total peak load based on assumptions in the 2024 Regional Forecast by the Pacific Northwest Utilities Conference Committee (PNUCC)[4].

Table 1 below shows the assumptions for determining the peak load for the region. In the case of BPA and PACW, historical peak load was used as a starting point. This peak load, however, was sourced from the EIA 930 and represents the total peak load for each balancing authority. To disaggregate to the study region of interest, we applied regional scaling factors. The BPA regional scaling factor was derived from county population data and resulted in taking 31% of the BPA total peak load. The PACW scaling

[3] The North of Pearl flowgate is another constrained transmission flowgate recently announced by BPA. This flowgate can restrict flows into the heart of PGE's service territory in West Portland. For our analysis, we have assumed the WOCS is the limiting constraint.

[4] https://www.pnucc.org/wp-content/uploads/2024-PNUCC-Northwest-Regional-Forecast-final.pdf

factor was derived from customer counts from PacifiCorp for relevant service areas and resulted in taking 31.1% of the peak load.

We then further adjusted the historical peak load for BPA and PACW to derive a 1 in 20-year peak by applying a scaling factor derived from the difference in the PACW peak load between a 1-in-2 and a 1-in-20-year forecast from the 2023 PacifiCorp Integrated Resource Plan (IRP)[5]. This results in an increase of 6.5% in historical peak load.

Table 1. Capacity requirement assumptions.

Area	Peak Load (MW)	Region adj.	1 in 20 adj.	AAGR
PGE	Forecasted Peak in 2026/2034	None	None	2.6%
BPAT_SW	Historical Peak in 2023	31% of BPA peak	6.5% of 1 in 2	2.7%
PACW	Historical Peak in 2023	31.1% of PACW peak	6.5% of 1 in 2	2.7%

For PGE, we obtained a 1-in-20-year peak load forecast from the 2024 Local Transmission Plan Heavy Summer Cases for the years 2026 and 2034. The load between these years was linearly interpolated, and the 2025 load was deescalated by the average annual growth rate. For all future years, we used the AAGR from PNUCC to estimate the load. According to the PNUCC the forecasted AAGR is based on load forecasts that account for energy efficiency programs.

The final peak load used in determining the supply/demand balance was calculated as the sum of the applicable load for each balancing authority multiplied by a coincident to non-coincident peak load ratio. This load ratio was derived from the EIA historical hourly data from 2015 to 2023 and equates to a 5% reduction in non-coincident peak load. The final load forecast is shown below in Figure 1, representing a 1-in-20-year coincident peak load forecast for the study region.

[5] https://www.pacificorp.com/energy/integrated-resource-plan.html

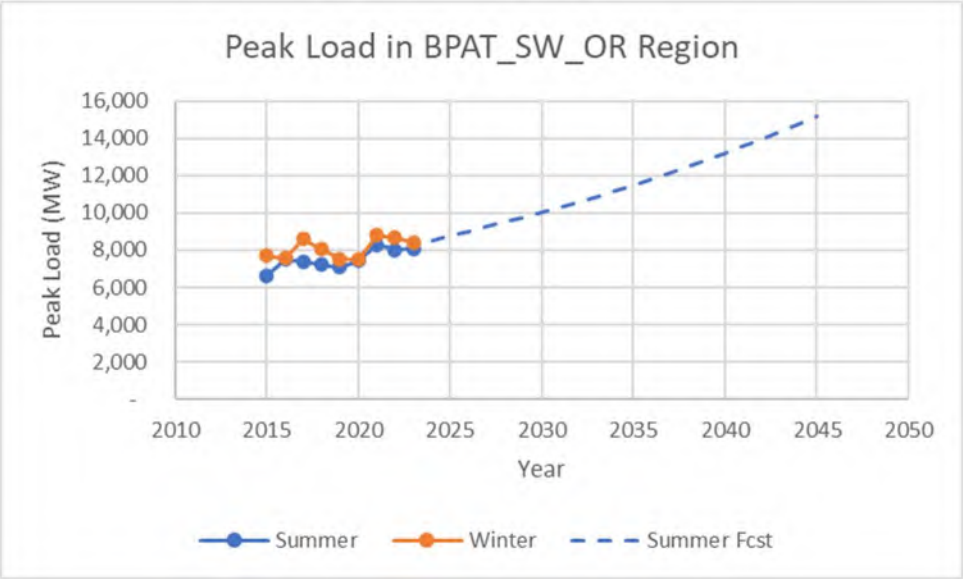


Figure 1. Peak load forecast.

Firm supply forecast

Firm supply for the region is broken down between firm imports and firm generation located within the region. Firm imports were defined from the path rating for the WCOS line and the South of Allston line. These are 5,962 MW and 3,100 MW for the WCOS and South of Allston lines, respectively. These values were derived from the BPA Total Transfer Capability (TTC) and the 2023 WECC Path Rating Catalog for the WCOS and South of Allston lines, respectively. The firm import capacity was held constant throughout the study period.

Firm generation is calculated for individual generating resources using a net qualifying capacity (NQC) value multiplied by the resource's seasonal rated capacity. For thermal units this ranges from 77% to 95% representing summer ratings and forced outage rates. For wind and solar this ranges from 21% to 27% based on actual operation during the top 100 net load hours like the WRAP concept of capacity critical hours (CCH). For hydro it is based on the WRAP estimates of 77%, and for storage it is set at 80%, also based on the WRAP estimates. The NQC in MW for each generating resource used in this study is shown Tables 6 and 7 in Appendix A.

Table 2. Net Qualifying Capacity (NQC) assumptions by technology. Resource specific NQC in MW is available in Appendix A.

Unit Type	NQC (%)
Gas	77% to 95%
Solar	21% to 27%
Hydro	77%
Storage	80%
Wind	21%

In addition to existing generators supplying firm capacity, we forecast demand response for the region that also provides firm capacity. To do this, we used a study by BPA[6] that provided a forecast of DR as a percentage of peak load. We applied this percentage to the peak load forecast for our study region to estimate the total DR potential by 2040. We then determined a growth rate in DR from current estimates of 104 MW of firm capacity in 2025 to the full potential of 885 MW of firm capacity in 2045.

Results and Discussion

Supply demand balance

The final supply demand balance is shown below. The full tables are available in Appendix A. The table below has rows for each year of the study period from 2025 to 2045 and columns corresponding to each major component of the supply/demand balance. In 2035, within five years of the anticipated start date of the Cascades Renewable Transmission Project, the firm demand is 11,267 MW, the losses are 901 MW, and the reserve margin requirement is 1,803 MW. These demand assumptions result in a firm demand requirement of 13,972 MW. The corresponding supply for 2035 is 9,062 MW of firm import capacity and 2,584 MW of firm generating capacity within the region for a total of 11,646 MW of firm supply. Therefore, the region is short of capacity by 2,325 MW in 2035. This capacity shortage increases throughout the study period to a maximum of 4,940 MW in 2045.

[6] https://www.bpa.gov/-/media/Aep/energy-efficiency/demand-response/bpa-demand-response-potential-assessment-2022-2043.pdf

Table 3. Summary of supply and demand balance.

Year	Firm Demand (MW)	Losses (MW)	Reserve Margin (MW)	Firm Capacity (MW)	Firm Imports (MW)	Net Firm Demand (MW)	Net Supply (MW)	Balance (MW)
2024	8,514	681	1,362	2,336	9,062	10,558	11,398	841
2025	8,779	702	1,405	2,349	9,062	10,887	11,411	524
2026	9,062	725	1,450	2,362	9,062	11,237	11,424	188
2027	9,341	747	1,495	2,372	9,062	11,583	11,434	(149)
2028	9,618	769	1,539	2,390	9,062	11,926	11,452	(474)
2029	9,881	791	1,581	2,410	9,062	12,253	11,472	(781)
2030	10,146	812	1,623	2,433	9,062	12,581	11,495	(1,086)
2031	10,402	832	1,664	2,458	9,062	12,899	11,520	(1,378)
2032	10,637	851	1,702	2,486	9,062	13,190	11,548	(1,642)
2033	10,831	866	1,733	2,515	9,062	13,430	11,577	(1,853)
2034	11,046	884	1,767	2,548	9,062	13,698	11,610	(2,088)
2035	11,267	901	1,803	2,584	9,062	13,972	11,646	(2,325)
2036	11,494	920	1,839	2,625	9,062	14,252	11,687	(2,565)
2037	11,726	938	1,876	2,670	9,062	14,540	11,732	(2,808)
2038	11,964	957	1,914	2,721	9,062	14,836	11,783	(3,052)
2039	12,208	977	1,953	2,779	9,062	15,138	11,841	(3,298)
2040	12,459	997	1,993	2,843	9,062	15,449	11,905	(3,544)
2041	12,715	1,017	2,034	2,915	9,062	15,767	11,977	(3,790)
2042	12,978	1,038	2,077	2,996	9,062	16,093	12,058	(4,036)
2043	13,248	1,060	2,120	3,086	9,062	16,428	12,148	(4,280)
2044	13,525	1,082	2,164	3,104	9,062	16,772	12,166	(4,606)
2045	13,809	1,105	2,210	3,122	9,062	17,124	12,184	(4,940)

Conclusions

This study demonstrates a system reliability need for increased supply to the western Oregon region. With the assumptions made in this document, the region becomes unreliable to meet a 1-in-20-year peak load by 2027. By 2030 the capacity shortage of the study region is over 1GW and by 2035 the capacity shortage exceeds 2.3 GW. To make the system reliable, either load must be reduced, or firm supply increased. In the case of load, it is likely that the assumptions here are low due to likely higher load growth rates from electrification of the transportation and residential, commercial, and industrial heating sectors. In the case of supply, new firm generating capacity in the region is limited and not expected to have significant contributions to reliability. Therefore, the Cross Cascades Renewable Transmission project, which would result in increased firm imports across the WOCS, SOA, and North of Pearl constraints is a transmission solution to meet reliability in this region.

Appendix A. Data Tables

Table 4. Supply and demand table for 2025 to 2034.

BPAT_SW (Western OR)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coincident Firm Demand	**8,779**	**9,062**	**9,341**	**9,618**	**9,881**	**10,146**	**10,402**	**10,637**	**10,831**	**11,046**
Non Coincident Firm Demand	9,441	9,744	10,045	10,342	10,626	10,911	11,186	11,438	11,647	11,156
PGE	4,905	5,055	5,189	5,327	5,468	5,614	5,763	5,916	6,073	6,253
PACW	1,368	1,415	1,465	1,513	1,556	1,598	1,636	1,666	1,682	1,697
BPAT_SW	3,167	3,275	3,391	3,502	3,601	3,699	3,787	3,857	3,892	3,929
Losses	702	725	747	769	791	812	832	851	866	884
Reserve Margin	1,405	1,450	1,495	1,539	1,581	1,623	1,664	1,702	1,733	1,767
Wholesale 1										
Conservation	-	-	-	-	-	-	-	-	-	-
Firm Imports	9,062	9,062	9,062	9,062	9,062	9,062	9,062	9,062	9,062	9,062
West of Cascades South	5,962	5,962	5,962	5,962	5,962	5,962	5,962	5,962	5,962	5,962
South of Allston	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100
Net Firm Demand	**10,887**	**11,237**	**11,583**	**11,926**	**12,253**	**12,581**	**12,899**	**13,190**	**13,430**	**13,698**
Net Supply	**11,411**	**11,424**	**11,434**	**11,452**	**11,472**	**11,495**	**11,520**	**11,548**	**11,577**	**11,610**
Balance	**524**	**188**	**(149)**	**(474)**	**(781)**	**(1,086)**	**(1,378)**	**(1,642)**	**(1,853)**	**(2,088)**

Table 5. Supply and demand table for 2035 to 2045.

BPAT_SW (Western OR)	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coincident Firm Demand	**11,267**	**11,494**	**11,726**	**11,964**	**12,208**	**12,459**	**12,715**	**12,978**	**13,248**	**13,525**	**13,809**
Non Coincident Firm Demand	12,116	12,360	12,609	12,865	13,128	13,397	13,673	13,956	14,247	14,544	14,850
PGE	6,438	6,629	6,825	7,027	7,235	7,450	7,670	7,898	8,131	8,372	8,620
PACW	1,713	1,729	1,745	1,761	1,778	1,794	1,811	1,828	1,845	1,862	1,879
BPAT_SW	3,965	4,002	4,039	4,077	4,115	4,153	4,192	4,231	4,270	4,310	4,350
Losses	901	920	938	957	977	997	1,017	1,038	1,060	1,082	1,105
Reserve Margin	1,803	1,839	1,876	1,914	1,953	1,993	2,034	2,077	2,120	2,164	2,210
Wholesale 1											
Conservation	-	-	-	-	-	-	-	-	-	-	-
Firm Imports	9,062	9,062	9,062	9,062	9,062	9,062	9,062	9,062	9,062	9,062	9,062
West of Cascades South	5,962	5,962	5,962	5,962	5,962	5,962	5,962	5,962	5,962	5,962	5,962
South of Allston	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100	3,100
Net Firm Demand	**13,972**	**14,252**	**14,540**	**14,836**	**15,138**	**15,449**	**15,767**	**16,093**	**16,428**	**16,772**	**17,124**
Net Supply	**11,646**	**11,687**	**11,732**	**11,783**	**11,841**	**11,905**	**11,977**	**12,058**	**12,148**	**12,166**	**12,184**
Balance	**(2,325)**	**(2,565)**	**(2,808)**	**(3,052)**	**(3,298)**	**(3,544)**	**(3,790)**	**(4,036)**	**(4,280)**	**(4,606)**	**(4,940)**

Table 6 NQC estimates by resource from 2025 to 2034.

BPAT_SW (Western OR)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Firm Capacity	**2,349**	**2,362**	**2,372**	**2,390**	**2,410**	**2,433**	**2,458**	**2,486**	**2,515**	**2,548**
Demand Response	104	118	135	153	173	196	221	249	278	311
small_res_agg OT area 8	5	5	5	5	5	5	5	5	5	5
small_res_agg OT area 22	74	74	74	74	74	74	74	74	74	74
small_res_agg OT area 24	12	12	12	12	12	12	12	12	12	12
Biomass One LP	25	25	25	25	25	25	25	25	25	25
Georgia-Pacific Wauna Mill	19	19	19	19	19	19	19	19	19	19
Evergreen BioPower LLC	9	9	9	9	9	9	9	9	9	9
IP Springfield Oregon	29	29	29	29	29	29	29	29	29	29
Seneca Sustainable Energy LLC	17	17	17	17	17	17	17	17	17	17
Georgia-Pacific Toledo Mill	12	12	12	12	12	12	12	12	12	12
Airport Solar	10	10	10	10	10	10	10	10	10	10
small_res_agg SUN area 22	40	40	40	40	40	40	40	40	40	40
small_res_agg SUN area 24	34	34	34	34	34	34	34	34	34	34
Brightwood Solar, LLC	3	3	3	3	3	3	3	3	3	3
small_res_agg STO area 24	4	4	4	4	4	4	4	4	4	4
Univ of Oregon Central Power Station	9	9	9	9	9	9	9	9	9	9
River Road Gen Plant	209	209	209	209	209	209	209	209	209	209
Oregon State University Energy Center	5	5	5	5	5	5	5	5	5	5
Clearwater 1	12	12	12	12	12	12	12	12	12	12
Prospect 2	25	25	25	25	25	25	25	25	25	25
Slide Creek	14	14	14	14	14	14	14	14	14	14
Lemolo 1	25	25	25	25	25	25	25	25	25	25
Toketee Falls	33	33	33	33	33	33	33	33	33	33
Clearwater 2	20	20	20	20	20	20	20	20	20	20
Lemolo 2	30	30	30	30	30	30	30	30	30	30
PHP 1	18	18	18	18	18	18	18	18	18	18
River Mill	14	14	14	14	14	14	14	14	14	14
Sullivan	12	12	12	12	12	12	12	12	12	12
Faraday	29	29	29	29	29	29	29	29	29	29
North Fork	31	31	31	31	31	31	31	31	31	31
Oak Grove	39	39	39	39	39	39	39	39	39	39
Big Cliff	14	14	14	14	14	14	14	14	14	14
Bonneville	895	895	895	895	895	895	895	895	895	895
Detroit	77	77	77	77	77	77	77	77	77	77
Hills Creek	23	23	23	23	23	23	23	23	23	23
Lost Creek	38	38	38	38	38	38	38	38	38	38
Cougar	20	20	20	20	20	20	20	20	20	20
Dexter	12	12	12	12	12	12	12	12	12	12
Green Peter	62	62	62	62	62	62	62	62	62	62
Lookout Point	62	62	62	62	62	62	62	62	62	62
Foster	15	15	15	15	15	15	15	15	15	15
Green Springs	13	13	13	13	13	13	13	13	13	13
Galesville Project	1	1	1	1	1	1	1	1	1	1
Dorena Hydro-Electric Facility	6	6	6	6	6	6	6	6	6	6
Carmen Smith	88	87	80	80	80	80	80	80	80	80
small_res_agg WAT area 8	6	6	6	6	6	6	6	6	6	6
small_res_agg WAT area 22	52	52	52	52	52	52	52	52	52	52
small_res_agg WAT area 24	19	19	19	19	19	19	19	19	19	19
small_res_agg WND area 22	26	26	26	26	26	26	26	26	26	26

Table 7. NQC estimates by resource from 2035 to 2045.

BPAT_SW (Western OR)	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Firm Capacity	**2,584**	**2,625**	**2,670**	**2,721**	**2,779**	**2,843**	**2,915**	**2,996**	**3,086**	**3,104**	**3,122**
Demand Response	347	388	433	484	542	606	678	759	849	867	885
small_res_agg OT area 8	5	5	5	5	5	5	5	5	5	5	5
small_res_agg OT area 22	74	74	74	74	74	74	74	74	74	74	74
small_res_agg OT area 24	12	12	12	12	12	12	12	12	12	12	12
Biomass One LP	25	25	25	25	25	25	25	25	25	25	25
Georgia-Pacific Wauna Mill	19	19	19	19	19	19	19	19	19	19	19
Evergreen BioPower LLC	9	9	9	9	9	9	9	9	9	9	9
IP Springfield Oregon	29	29	29	29	29	29	29	29	29	29	29
Seneca Sustainable Energy LLC	17	17	17	17	17	17	17	17	17	17	17
Georgia-Pacific Toledo Mill	12	12	12	12	12	12	12	12	12	12	12
Airport Solar	10	10	10	10	10	10	10	10	10	10	10
small_res_agg SUN area 22	40	40	40	40	40	40	40	40	40	40	40
small_res_agg SUN area 24	34	34	34	34	34	34	34	34	34	34	34
Brightwood Solar, LLC	3	3	3	3	3	3	3	3	3	3	3
small_res_agg STO area 24	4	4	4	4	4	4	4	4	4	4	4
Univ of Oregon Central Power Station	9	9	9	9	9	9	9	9	9	9	9
River Road Gen Plant	209	209	209	209	209	209	209	209	209	209	209
Oregon State University Energy Center	5	5	5	5	5	5	5	5	5	5	5
Clearwater 1	12	12	12	12	12	12	12	12	12	12	12
Prospect 2	25	25	25	25	25	25	25	25	25	25	25
Slide Creek	14	14	14	14	14	14	14	14	14	14	14
Lemolo 1	25	25	25	25	25	25	25	25	25	25	25
Toketee Falls	33	33	33	33	33	33	33	33	33	33	33
Clearwater 2	20	20	20	20	20	20	20	20	20	20	20
Lemolo 2	30	30	30	30	30	30	30	30	30	30	30
PHP 1	18	18	18	18	18	18	18	18	18	18	18
River Mill	14	14	14	14	14	14	14	14	14	14	14
Sullivan	12	12	12	12	12	12	12	12	12	12	12
Faraday	29	29	29	29	29	29	29	29	29	29	29
North Fork	31	31	31	31	31	31	31	31	31	31	31
Oak Grove	39	39	39	39	39	39	39	39	39	39	39
Big Cliff	14	14	14	14	14	14	14	14	14	14	14
Bonneville	895	895	895	895	895	895	895	895	895	895	895
Detroit	77	77	77	77	77	77	77	77	77	77	77
Hills Creek	23	23	23	23	23	23	23	23	23	23	23
Lost Creek	38	38	38	38	38	38	38	38	38	38	38
Cougar	20	20	20	20	20	20	20	20	20	20	20
Dexter	12	12	12	12	12	12	12	12	12	12	12
Green Peter	62	62	62	62	62	62	62	62	62	62	62
Lookout Point	62	62	62	62	62	62	62	62	62	62	62
Foster	15	15	15	15	15	15	15	15	15	15	15
Green Springs	13	13	13	13	13	13	13	13	13	13	13
Galesville Project	1	1	1	1	1	1	1	1	1	1	1
Dorena Hydro-Electric Facility	6	6	6	6	6	6	6	6	6	6	6
Carmen Smith	80	80	80	80	80	80	80	80	80	80	80
small_res_agg WAT area 8	6	6	6	6	6	6	6	6	6	6	6
small_res_agg WAT area 22	52	52	52	52	52	52	52	52	52	52	52
small_res_agg WAT area 24	19	19	19	19	19	19	19	19	19	19	19
small_res_agg WND area 22	26	26	26	26	26	26	26	26	26	26	26

Appendix B. Input Assumptions and References

Table 8. Sources used for major assumptions.

Assumption	Source
Historical Load	EIA 930
PGE Peak Load	2024 Local Transmission Plan
Regional Load BPA	County Population
Regional Load PACW	Customer count
Transmission Losses	2017 Idaho Power IRP
Planning Reserve Margin	PNUCC 2024 Regional Forecast
Average Annual Growth Rate	PNUCC 2024 Regional Forecast
Coincident to non-coincident Ratio	EGPS analysis; EIA 930
NQC Hydro	WPP WRAP
NQC Thermal, Renewable	EGPS

Attachment 4. BPA Evolving Grid Project (EGP) 1.0 Summaries

Evolving Grid Project (EGP) 1.0 Summaries

EGP 1.0 consists of 10 proposed projects at a preliminary projected cost of $2 billion to support the region's electrification and clean energy goals.

Rock Creek-John Day 500 kV Line Upgrade

This project is an upgrade of the existing Rock Creek – John Day #1 500-kV line. BPA would rebuild 14 miles of line between the Rock Creek Substation (Goldendale, WA) and John Day Substation (Rufus, OR), including a Columbia River crossing.

This project will create additional capacity to support regional load growth, reliability needs and commercial requests for long-term transmission at a preliminary estimated direct cost of $37 million.

Estimated completion: Early 2030 (updated)

Big Eddy-Chemawa 230/500 kV Line Upgrade

This project is a rebuild of portions of the existing Big Eddy-Chemawa #1 230 kV line to 500 kV. BPA proposes to rebuild and re-terminate 91 miles of line between BPA's Big Eddy Substation (The Dalles, OR), Ostrander Substation (Oregon City, OR) and Pearl Substation (Wilsonville, OR).

This project will create additional capacity to support regional load growth, reliability needs and commercial requests for long-term transmission at a preliminary estimated direct cost of $670 million.

Estimated completion: 2032

Cross Cascades North Upgrades

This series of upgrades consists of three projects designed to reinforce the Cross Cascades North path on the FCRTS.

- Schultz-Raver 500 kV Line Upgrade: BPA proposes upgrading the existing Schultz-Raver #3 and Schultz-Raver #4 500-kV lines to a higher rated capacity. BPA would reconductor the 77 miles of line between BPA's Schultz Substation (Ellensburg, WA) and Raver Substation (Ravensdale, WA).
- Paul 500 kV Substation Upgrade: BPA proposes adding a new capacitor at Paul Substation (Centralia, WA).
- Olympia 230 kV Substation Upgrade: BPA proposes adding a new Static VAR Compensator at Olympia Substation (Olympia, WA).

This project will create additional capacity to support regional load growth, reliability needs and commercial requests for long-term transmission at a preliminary estimated direct cost of $400 million.

Estimated completion: 2031 (updated)

Ross-Rivergate 230 kV Line Upgrade

This project is a proposed upgrade of the existing Ross-Rivergate #1 230 kV line. The work would consist of replacing conductor on 7.5 miles of line between BPA's Ross Substation (Vancouver, WA) and PGE's Rivergate Substation (Portland, OR), including a Columbia River crossing.

This project will create additional capacity to support regional load growth, reliability needs and commercial requests for long-term transmission at a preliminary estimated direct cost of $50 million.

Estimated completion: 2029 (updated)

Chehalis-Covington 230 kV Line Upgrade

This project is a proposed upgrade of a portion of the existing Chehalis-Covington #1 230-kV line. The work would consist of replacing conductor on 35 miles of line between BPA's Chehalis Substation (Chehalis, WA) and Cowlitz Tap (Frederickson, WA).

This project will create additional capacity to support regional load growth, reliability needs and commercial requests for long-term transmission at a preliminary estimated direct cost of $95 million.

Estimated completion: 2028

Portland Area Upgrades

Keeler-Horizon 230 kV Line #2 - Completed (energized 2024)

Terminating PGE's new Keeler-Horizon #2 line at BPA's Keeler Substation (Hillsboro, OR) and a new 500/230-kV transformer would also be added at Keeler Substation.

Pearl-Sherwood-McLoughlin 230 kV Line Upgrade

Reconfiguring and re-terminating the Pearl-Sherwood-McLoughlin line at BPA's Pearl Substation (Wilsonville, OR).

Estimated completion: Summer 2026

Keeler 230/500 kV Transformer Addition

A new 500/230-kV transformer would also be added at Keeler Substation (Hillsboro, OR).

Estimated completion: 2029

In total, these projects will create additional capacity to support regional load growth, reliability needs and commercial requests for long-term transmission at a preliminary estimated direct cost of $150 million.

Bonanza 230/500 kV Substation

This facility would be a new hub substation in Central Oregon near Prineville, OR. The new 115/230/500 kV Bonanza Substation would be built near BPA's existing Ponderosa Substation.

This project will create additional capacity to support new resource development and access to non-federal resources at a preliminary estimated direct cost of $300 million.

Estimated completion: 2028 (updated)

La Pine-Bonanza 230 kV Line

This project is a proposed new 53-mile 230-kV transmission line in Central Oregon between BPA's La Pine Substation (La Pine, OR) and proposed Bonanza Substation (Prineville, OR).

This project will create additional capacity to support regional load growth, reliability needs and commercial requests for long-term transmission at a preliminary estimated direct cost of $150 million.

Estimated completion: Late 2029

Six Mile Canyon 230/500 kV Substation

This is a proposed new 230/500-kV hub substation called Six Mile Canyon near Boardman, OR.

This project will create additional capacity to support regional load growth, reliability needs and commercial requests for long-term transmission at a preliminary estimated direct cost of $250 million.

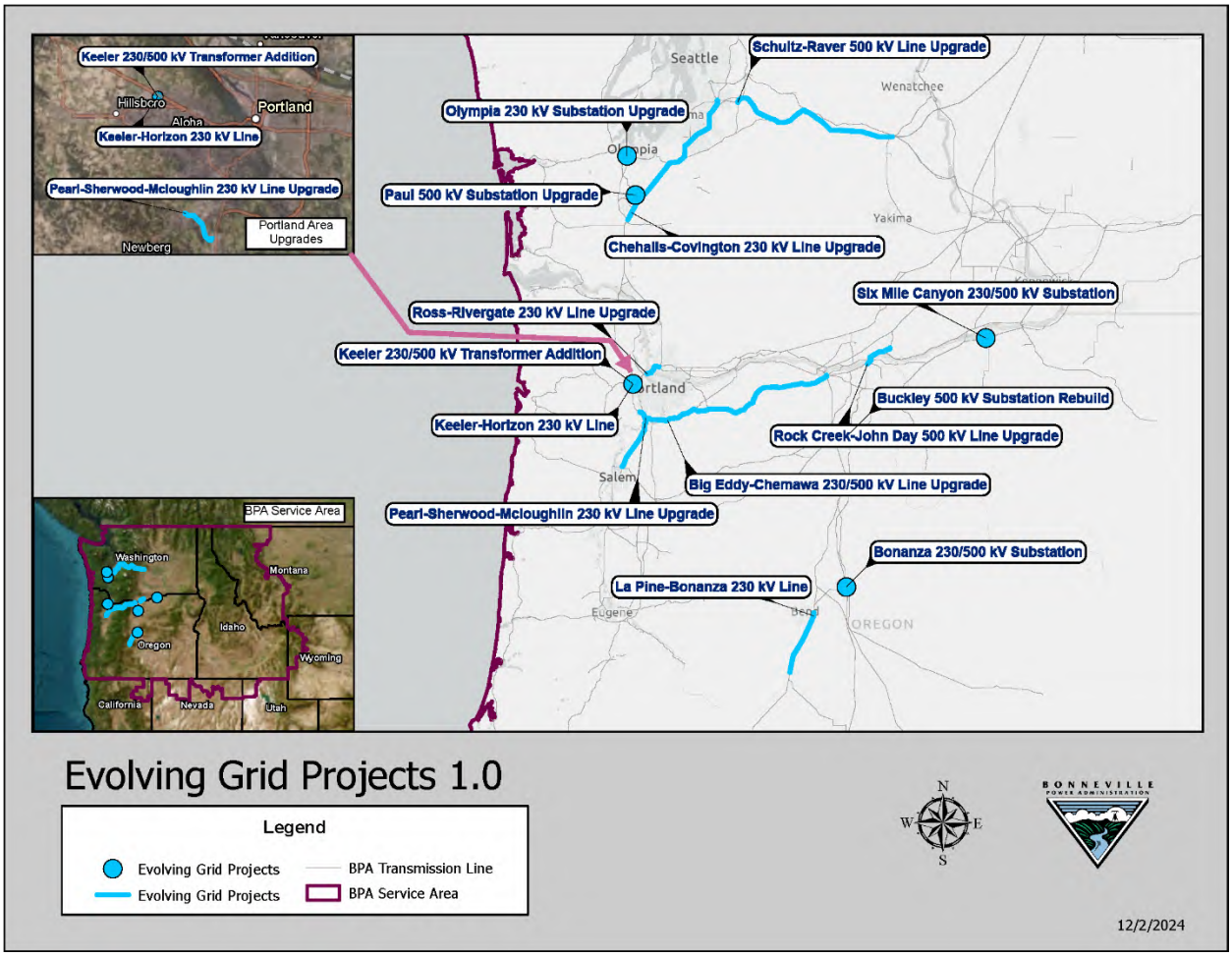
Estimated completion: Late 2027/Early 2028 (updated)

Buckley 500 kV Substation Rebuild

This project is a proposed rebuild of BPA's Buckley Substation in Sherman County, OR. It would be a new air-insulated 500-kV substation built near the existing gas-insulated substation, which will be retired.

This project will create additional capacity to support regional load growth, reliability needs and commercial requests for long-term transmission at a preliminary estimated direct cost of $150 million.

Estimated completion: 2028 (updated)



Attachment 5. BPA Evolving Grid Project (EGP) Summaries 2.0

Evolving Grid Project (EGP) 2.0 Summaries

EGP 2.0 consists of 13 proposed projects at a preliminary projected cost of $3 billion to support the region's electrification and clean energy goals.

Grand Coulee-Columbia-Schultz 500 kV Line Upgrade

This proposed project would rebuild the existing Grand Coulee-Olympia 287 kV circuit to 500 kV. To loop into Columbia, the project would also build a new Columbia 500 kV substation yard, with a 500/230 kV transformer bank. This section of the line would terminate at Schultz Substation.

Schultz-Olympia 500 kV Line Rebuild

This proposed project would rebuild the Schultz-Olympia portion of the Coulee-Olympia 287 kV to 500 kV. The project would also include an expansion of an Olympia 500 kV yard, a new 500/230 kV transformer bank, and three new 500 kV shunt capacitors.

Central Oregon 500 kV Dynamic Reactive Upgrades

This proposed project would install reactive support (STATCOM) for Central Oregon at Bonanza 500 kV and a Captain Jack 500 kV.

RATS: Reno-Alturas Reactive Addition

This proposed project would install reactive support (STATCOM) at Warner 115 kV and Hilltop 230 kV.

Salem Area Upgrades

These proposed upgrades would build on the Big Eddy-Chemawa project in EGP 1.0:

North of Marion Upgrade #1:

- Constructing a new 500 kV yard at Chemawa, including a new 500/230 kV transformer bank
- Rebuild the Pearl – Chemawa section of Big Eddy-Chemawa from 230 kV to 500 kV
- Rebuild the Chemawa – Santiam #1 from 230 kV to 500 kV

North of Marion Upgrade #2:

- Rebuild Pearl – Marion #1 500 kV transmission line and replace the 2.5" expanded conductor
- Rebuild the Oregon City – Chemawa 115 kV transmission line river crossing
- Add a second 230/115 kV transformer bank at Chemawa Substation

North of Pearl

This proposed project would upgrade transmission capacity in the Portland sub-grid North of Pearl area by reconductor the existing Pearl-Keeler #1 500 kV line and leveraging an existing corridor to add a second 500 kV line between Pearl and Keeler.

The existing Pearl-Sherwood #1 and #2 230 kV transmission lines would be relocated/rebuilt to accommodate Pearl-Keeler #2 500 kV line.

The existing section of Keeler-Oregon City #2 115 kV between Sherwood and Oregon City would be repurposed as the new Keeler-Sherwood (PGE) 115 kV Line, terminating into Sherwood.

Big Eddy-Quenett Creek 230 kV Line Upgrade

This proposed project would upgrade the Hood River sub-grid, rebuilding the Big Eddy-Quenett Creek 230 kV to resolve the river crossing impairment.

Ostrander-Pearl #1 500 kV Line Upgrade

This proposed project would upgrade the Ostrander-Pearl #1 500 kV line and replace the existing 2.5” expanded conductor.

Big Eddy-The Dalles Rebuild

This proposed project is currently under study with Northern Wasco PUD to rebuild a 115 kV line BPA currently leases.

Lower Columbia to Nevada-Oregon Border

Lower Columbia to Bonanza

This proposed project would build a new 500 kV transmission line between a substation in the Lower Columbia area and the planned Bonanza Substation in Central Oregon. It may include additional connections to 500 kV substations near the line route as well as new 500 kV series capacitors.

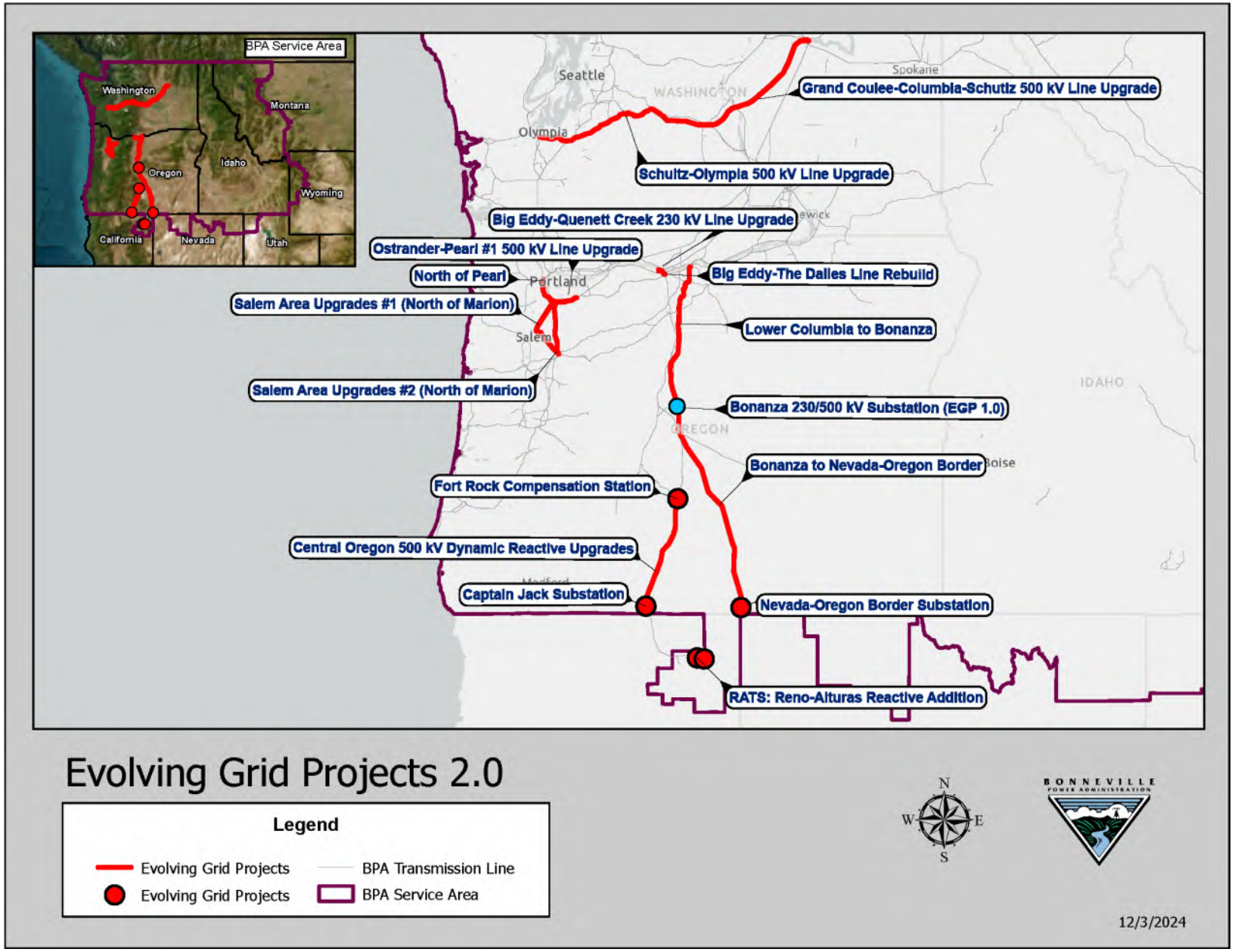
Bonanza to NOB

This proposed project would build a new 500 kV transmission line from Bonanza Substation toward the Nevada-Oregon border (NOB). The project would also include new 500 kV series capacitors.

Nevada-Oregon Border Substation

This proposed project would build a new 500 kV substation at the Nevada-Oregon border.

(continues)


BPA Service Area
Washington
Montana
Oregon
Idaho
Wyoming
California
Nevada
Utah
Seattle
Spokane
WASHINGTON
Olympia
Portland
Salem
IDAHO
OREGON
Boise
Grand Coulee-Columbia-Schutlz 500 kV Line Upgrade
Schultz-Olympia 500 kV Line Upgrade
Big Eddy-Quenett Creek 230 kV Line Upgrade
Ostrander-Pearl #1 500 kV Line Upgrade
North of Pearl
Big Eddy-The Dalles Line Rebuild
Salem Area Upgrades #1 (North of Marion)
Lower Columbia to Bonanza
Salem Area Upgrades #2 (North of Marion)
Bonanza 230/500 kV Substation (EGP 1.0)
Bonanza to Nevada-Oregon Border
Fort Rock Compensation Station
Central Oregon 500 kV Dynamic Reactive Upgrades
Captain Jack Substation
Nevada-Oregon Border Substation
RATS: Reno-Alturas Reactive Addition
Evolving Grid Projects 2.0
Legend
Evolving Grid Projects
Evolving Grid Projects
BPA Transmission Line
BPA Service Area
N
W
E
S
BONNEVILLE POWER ADMINISTRATION
12/3/2024

Attachment 6. PGE CEP-IRP 2023 Addendum

Portland General Electric
121 SW Salmon Street • Portland, OR 97204
portlandgeneral.com

July 7, 2023

Via Electronic Filing

Public Utility Commission of Oregon
Attention: Filing Center
P.O. Box 1088
Salem, OR 97308-1088

Re: LC 80 – Portland General Electric Company's 2023 Clean Energy Plan and Integrated Resource Plan Addendum: Portfolio Analysis Refresh

Dear Filing Center:

Enclosed for filing in the above-referenced docket is Portland General Electric Company's (PGE) Addendum: Portfolio Analysis Refresh (Addendum) to its 2023 Clean Energy Plan (CEP) and Integrated Resource Plan (IRP). The Addendum incorporates several input forecasts of demand and generation supply that are used to estimate system needs. The Addendum also includes PGE's reevaluation of its portfolio analysis based on this updated information. The updates provided in this addendum required updates to the CEP data template that accompanied the CEP/IRP. As such, a CEP data template addendum is being included with this filing.

Kristen Sheeran, PGE's Director of Sustainability and Resource Planning, leads PGE's CEP and IRP work. Please direct any questions or communications regarding these comments to: pge.opuc.filings@pgn.com.

Sincerely,

/s/ Riley Peck

Riley Peck
Senior Manager, Regulatory Strategy
Resource & Regulatory Strategy

2023 Clean Energy Plan and Integrated Resource Plan

Addendum: System Need & Portfolio Analysis Refresh

This document contains forward-looking statements, including those regarding implementation of our business plans, technology transitions, our business, strategies and financial performance, our offerings of new services, and other statements that are not historical fact, and actual results could differ materially from these forward-looking statements. Risk factors that could cause actual results to differ are set forth in the "Risk Factors" section, as well as other sections of our 2022 Annual Report on Form 10-K, available on our website at investors.portlandgeneral.com/financial information/sec-filings, as well as, or in addition to, other filings with the SEC. All forward-looking statements are based on management's estimates, projections, and assumptions as of the date of filing, and we undertake no obligation to update any such statements.

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Introduction

The first step in the development of the 2023 CEP/IRP was an estimation of long-term system needs. These needs are calculated as the difference between the system demand for electricity and the supply of existing and contracted generation to meet it. There are two main types of system need:[1,2]

1. *Energy need*: The average amount of system deficit expected over a typical year, expressed in average MW (MWa)
2. *Capacity need*: The resource deficit experienced in times of peak need, expressed in effective capacity (MW)

The 2023 CEP/IRP relies on many input forecasts of both future supply and demand to estimate this need. Since the preparation of the CEP/IRP analysis and its filing in March 2023, several of these forecasts have been updated. The first purpose of this Addendum is to introduce those updates and quantify their impacts on system need. While there are some off-setting effects described below, since the March 2023 filing there has been a sharp increase in nearly all input forecasts resulting in significantly higher system need. Each of the updated input forecasts are detailed in **Chapter 1, Input updates** and the resulting energy and capacity needs are detailed in **Chapter 2, Need changes**.

The second purpose of this Addendum is to reevaluate portfolio analysis based on this updated information. The filed CEP/IRP's portfolio analysis posed several core questions in resource planning. This Addendum asks if the answers PGE provided in the filed CEP/IRP still hold true given the updated input forecasts and the resulting increased estimated system needs. We find those main findings, filed at the end of March, are still valid and now, more supported by these updated input forecasts. In addition, our proposed path to compliance with 2030 emissions targets remains the same. PGE's decarbonization path still requires us to procure sufficient non-emitting energy and capacity resources to systematically reduce fossil fuel generation and purchases associated with Oregon retail load. Our procurement strategies and timing of RFPs will be updated to reflect this increased resource need. This increased resource need also further underscores the critical need to address regional transmission constraints. On-system resources like energy efficiency and community-based

[1] Previous IRPs focused on RPS need as well. However, the non-emitting generation need established by the emission reduction targets in HB 2021 is substantially greater than any applicable RPS constraints. While there was some information in the filed CEP/IRP, this document does not focus on RPS need as it does not drive resource need under any future modeled.

[2] PGE also estimates the flexibility need of the system. The relationship between the flexibility and capacity need is such that only the larger of the two drive resource decisions. Given that the capacity need is significantly higher than the flexibility need, flexibility need is not considered a driver of resource additions within current IRP modeling.

renewable energy (CBRE) resources each are identified as an important part of PGE's resource mix going forward. The increased system need still points to a linear reduction as the most appropriate choice of modeling emissions through 2030. While the size of the incremental resource additions does increase with system need, this Addendum supports the appropriateness of the answers from portfolio analysis and the construction of the Preferred Portfolio, which forms PGE's pathway to 2030 compliance. Similarly, the increase in resources identified in this Addendum do not change the structure of either our Action Plan or our pathway towards 2030. The proposed actions still rely on customer demand-side actions, CBRE acquisitions, increased transmission access, and new resources to meet energy and capacity needs.

Chapter 1. Input updates

Input forecasts create the basis of CEP/IRP estimation of system needs. Since the March 31, 2023 filing, several input forecasts have been updated. Additionally, several methodological changes have been made for this Addendum. These updated input forecasts and methodological changes and magnitudes of their changes are described below.

1.1 Load forecast

Generally, long-term forecasts of load are the first input to be finalized during the development of an IRP. For example, the 2019 IRP (filed in July 2019) finalized its forecast of load in September of 2018. The 2023 CEP/IRP used the March 2022 load forecast for most analysis but did include a sensitivity looking at the December 2022 load forecast as well. In this addendum PGE has updated the load forecast to the June 2023 vintage.

PGE's load forecast methodology includes near term and long-term components, as reflected in Table 99 of Appendix D in the filed CEP/IRP. PGE updates its long-term model specifications during the IRP cycle with periodic updates to the stakeholder audience. These long-term models have not changed as compared to those models presented in the 2023 CEP/IRP.

The near-term load forecast model is updated more frequently, several times each year as new information is available. In the past 18 months, PGE's industrial class load has grown rapidly, at a rate of 10.6 percent in 2022 and 8.3 percent in the first quarter of 2023. The primary driver of PGE's increased load forecast is to reflect rapid industrial growth and growing demand of data centers in PGE's service territory.

In addition, PGE has made several refinements to its near-term load forecast methodology. The data aggregation has been changed to reflect residential dwelling type and non-residential rate schedule groupings rather than previous dwelling and heat type groupings and industry (NAICS) segment non-residential groupings. The new model structure and additional months of data included allow for a simplified approach to capturing the impact of COVID-19. In the commercial models, there is no longer a need for manual indicators, rather economic drivers adequately capture the impact in the historical period.

In March 2022 PGE assumed that the long-term impacts of COVID-19 on residential usage would be one-third of the initial impact. This assumption, along with other decreasing trends in residential use per customer, resulted in a forecasted 4.4 percent decrease in use-per-customer for 2022. As time has passed and more usage data has become available, initial lockdown is now controlled for in the historical period and the uptick since this period is modeled as a permanent shift. Specifically, the early impacts of COVID-19 are captured by

indicating the first six months of the pandemic when lockdowns were at their peak and an indicator variable, which begins in April of 2020 and continues into perpetuity, is interacted with weather variables. These interactions account for the change in residential customers' response to weather due to increased time spent at home. This update in assumptions does not change the long-term growth rates of residential customers but rather resulted in a level shift in the near-term usage as we no longer assume a drop in usage due to the unwinding of COVID-19. These changes are summarized in **Table 1** below.

Table 1. Key updates in input assumptions and model structure

	March 2022 Forecast	June 2023 Forecast
Historical Data	Ending January 2022	Ending April 2023
Economic Forecast	OEA February 2022	OEA May 2023
COVID-19	Multiple complex indicator variables Assumption of greater return to pre-pandemic levels for residential customers	Simplified drivers Assumes that status quo has been reached and residential usage will not see a drop off due to return to office
Residential Groups	Dwelling Type & Heat Type	Dwelling Type
Non-residential Groups	NAICS (18 models)	Rate Schedule (5 models)

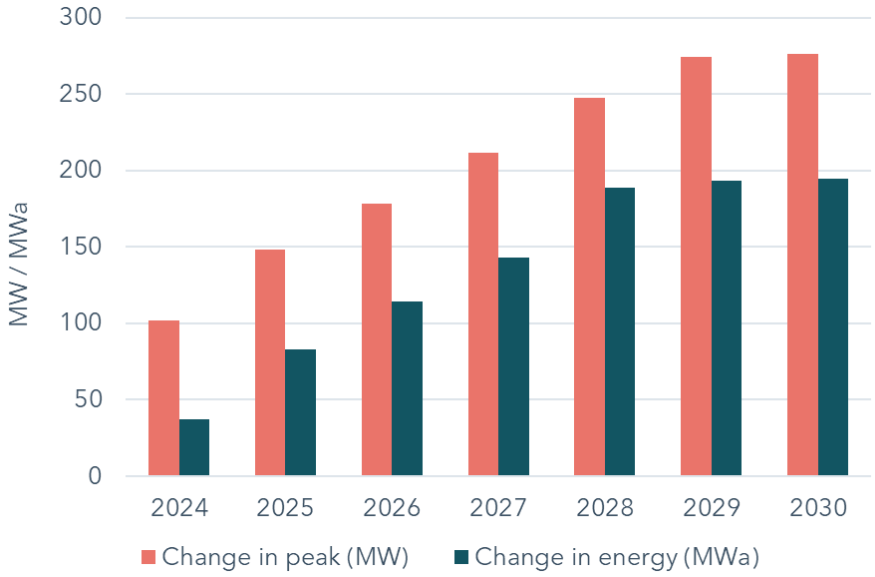
The result of this update is summarized below by replicating the average annual growth rates as shown in **Table 2**. Since only the 5-year portion of the model is updated, these changes are front weighted.

Table 2. Reference Case top down econometric 20-year AAGR (2023-2042)

Vintage	Total Energy	Peak	Residential	Commercial	Industrial
March 2022	1.2%	0.8%	0.5%	0.0%	3.5%
June 2023	1.6%	1.1%	0.6%	0.0%	3.9%

Aggregated, these changes lead to significantly higher forecasts of system needs. The magnitudes of these changes in both energy and capacity (in MWa and MW) are displayed below in **Figure 1**.

Figure 1. March 2022 to June 2023 load forecast changes



1.2 Distributed energy resources

PGE continues to experience growth of distributed energy resources (DERs) on the system driven by strong customer demand and favorable federal, state, and local policies. Like the load forecast described in **Section 1.1, Load forecast**, the DER forecast is a key input to CEP/IRP analysis at the start of the modeling workflow. Like the load forecast, the 2023 CEP/IRP used the March 2022 vintage of the DER forecast that was filed in the DSP Part 2 for most analyses.[3]

The most notable changes in policy that affect the DER forecast since the vintage used in the filing of the 2023 CEP/IRP are the Inflation Reduction Act (IRA) and Oregon's adoption of the Advanced Clean Cars II rule.[4] This section presents results from our most recent DER forecast update.

[3] Like the load forecast described in **Section 1.1**, the Low, Reference, and High Need Futures leveraged the March 2022 DER forecast vintage, but additional sensitivity cases were conducted with additional DER growth as described in Section 6.10.22 of the 2023 CEP/IRP.

[4] The 2023 CEP/IRP accounted for IRA influence on supply-side technology cost changes driven by the legislation. PGE did not include explicit accounting of the IRA impacts on DER until the forecast update described in this section. However, some of the DER sensitivity cases in the 2023 CEP/IRP did account for large DER growth.

1.2.1 DER forecast update overview

AdopDER is PGE's enterprise DER modeling tool used to forecast DER adoption and calculate expected load impacts for critical PGE business functions. PGE uses the tool to forecast DER growth and potential impacts from the bottom-up, aggregating site-level adoption up to the feeder and ultimately the bulk power system level. The tool is consistently used to inform DSP forecasting, the CEP/IRP, corporate load forecasting, and various other PGE functions about the expected impact stemming from customer DER adoption and consequent changes to overall system energy demand patterns.

AdopDER is a unique hybrid model for assessing DER growth, leveraging top-down customer growth estimates determined by the corporate load forecast, and pairs this with bottom-up insights about customer behavior and DER resource availability to inform an overall picture of DER adoption. For more information on AdopDER and how it interacts with the corporate load forecast, see Section 3.5 of the DSP Part 2.[5]

The full suite of potential impacts of the IRA on DER adoption will take more time to assess and understand as the longer-term provisions and supply-chain responses come into clearer focus, such as onshore manufacturing incentives and requirements. Our DER forecast update focuses on the most near-term elements within the legislation that impact our forecast methodologies.[6] However, across all DER types we do see a steady increase over time in terms of adoption following this update. The main areas of change were:

- Transportation electrification update: reflecting passage of Oregon DEQ's Advanced Clean Cars II rule and the EV tax incentives in the IRA, as well as updated DMV registrations and econometric forecast calibration
- Solar PV and storage update: reflecting recent acceleration of PGE's interconnection queue and changes in IRA regarding the Investment Tax Credit (ITC)
- Building electrification update: reflecting increased incentives stemming from policy changes such as the IRA

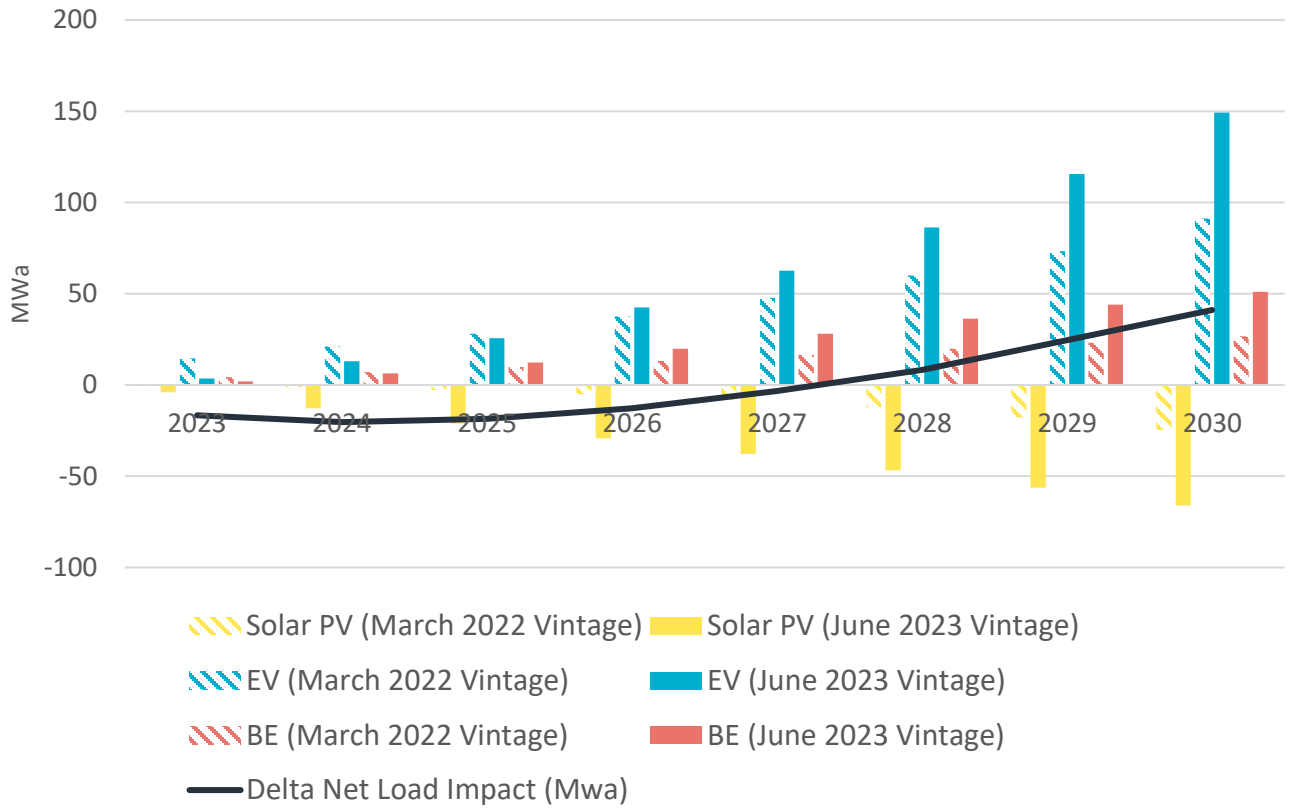
[5] DSP Part 2 is available at: https://downloads.ctfassets.net/416ywc1laqmd/2Fr2nVc4FKONetiVZ8aLWM/b209013acfedf1125ceb7ba2940bac71/DSP_Part_2_-_Full_report.pdf

[6] This DER forecast update includes only solar PV, transportation and building electrification. Demand response (DR) programs, including distributed standalone storage, are not reflected here. Because these resources are modeled in the technical achievable potential within the IRP, changes to the selection of those resources are addressed through portfolio modeling.

1.2.2 DER forecast results

Figure 2 shows the high-level DER changes by category from the March 2022 DER forecast vintage that informed most of the 2023 CEP/IRP analysis compared to the updated June 2023 DER forecast vintage.[7] The net annual energy impact is a decrease until 2027 and a net increase beginning in 2028.[8]

Figure 2. Aggregated forecasted distributed energy resource changes



In the initial years, the forecast is slightly reduced compared to the previous forecast used in the CEP/IRP because of the updated customer adoption and near-term market trends that were recalibrated, while longer-term the growth in electrification is partially offset by an increase in the solar adoption forecast. In aggregate, the combined DERs will add 41 MWa of

[7] Note these MWa represent incremental additions starting from the base year of the forecast (2022) in order to separate from the DER that are effectively embedded in the corporate load forecast. Therefore, they do not represent the total DER on the system.

[8] This is strongly influenced by the solar PV update, which has the highest percentage change between the forecast vintages, though in the longer term less energy impact compared to electrification. The relatively higher change in the distributed solar forecast is due to the combined influence of adding IRA incentives as well as accounting for the recent uptick in rooftop solar applications that continued throughout 2022 even before the passage of the IRA.

additional load to our baseline corporate load forecast by 2030, increasing overall energy need.

Although the impact of DERs that add load (e.g., transportation electrification) or generation (e.g., distributed solar) can offset each other from an average annual energy demand perspective, integrating these growing DERs interconnected to the distribution grid will require careful planning and integration to minimize system costs and maximize their potential for shifting load and providing additional grid services as discussed in PGE's DSP Part 2.

1.3 2021 All-Source RFP

The 2021 All-Source RFP began with acquisition targets of 500 MW of capacity and up to 150 MWa of energy to meet the 2025 resource adequacy deficit.[9] The energy target was later increased to up to 250 MWa in the UM 2166 docket, and the capacity target decreased to 388 MW.[10]

The 2023 CEP/IRP was published before the conclusion of the 2021 All-Source RFP. To avoid adding incremental resources to fill need that would be met with resources acquired in that RFP, the CEP/IRP relied on a proxy set of resources in its analysis. By the filing of the CEP/IRP the company did have certainty of one resource (the Clearwater wind project), which is included in its analysis. The remainder of the RFP proxy included sufficient solar and stand-alone storage to meet the remaining RFP acquisition targets (this amounted to 410 MW of generic solar resource and 400 MW of four-hour batteries). These resources are included in the projected energy load-resource balance displayed in the filed CEP/IRP's Figure 42.

In May 2023 PGE announced the conclusion of the 2021 RFP. In addition to Clearwater Wind, the RFP acquired three four-hour battery projects totaling 475 MW. The difference between the RFP proxy and the actual resources acquired in the 2021 All-Source RFP are displayed in **Table 3**.

Table 3. 2021 RFP proxy vs actual 2021 All-Source RFP acquisitions

2023 CEP/IRP 2021 RFP proxy		2021 RFP procurement	
Resource	Nameplate MW	Resource	Nameplate MW
Clearwater Wind	311	Clearwater Wind	311
Proxy solar	410	Troutdale 4-hr battery	200
4-hr battery	400	Seaside 4-hr battery	200
		Evergreen 4-hr battery	75

[9] UM 2166, page 1 & 2: https://edocs.puc.state.or.us/efdocs/HAA/um2166haa173953.pdf
[10] UM 2166, Order 22-315, page 5.

Updating from the RFP proxy to using the actual projects has three primary impacts on the PGE planning models:

1. *Energy need increases:* The need to acquire non-emitting energy resources, like wind and solar, increases as fewer renewables were acquired than included in the proxy.
2. *Winter capacity need decreases:* The additional battery (75 MW more in the actual than the proxy) provides more winter capacity than the proxy solar resources.[11]
3. *Summer capacity need remains:* The additional capacity provided by the increased storage is roughly offset by the reduction in capacity from the RFP proxy's solar.

1.4 Storage resources

Throughout the cycle of charging and discharging a battery, some energy is lost from the roundtrip efficiency of the battery system. As the energy lost by current quantities of storage is not substantial, PGE has not previously accounted for them in energy need accounting. However, as large quantities of batteries are planned to be added to the system, the losses are projected to be non-trivial. For this Addendum energy losses have been added for the 475 MW of RFP storage resources and the 23 MW of existing storage PPAs. Losses were calculated using simulated average annual capacity factors from Aurora of -1.4 percent for the 4-hr storage proxy resource.[12] Accounting for energy losses from storage results in an increase in energy need on average by 7 MWa per year. The capacity need model (Sequoia) already has incorporated storage losses into need and ELCC calculations; as a result no adjustments are needed to the capacity need values for storage losses.

1.5 Qualifying facilities update

The 2023 CEP/IRP uses qualifying facility inputs (facilities contracted under PGE's Schedule 201 or Schedule 202) that were updated in December 2022. From December 2022 to June 2023 there have been changes to qualifying facilities that have resulted in an approximately 161 MW nameplate net decrease of generation resources. The majority (160 MW) of this change is due to solar qualifying facilities terminating their contracts with PGE (the remaining 1 MW is from correcting IRP input errors).

[11] Those solar resources were assumed to use conditional-firm transmission, which reduced their capacity contribution values.
[12] The market simulation that creates these capacity factors (Aurora PZM model) limits storage cycling to an average of once per day on an annual basis.

The impact to PGE's planning models of switching to updated qualifying facility inputs is increased need for non-emitting resources and increased need for capacity resources in both the summer and winter.

1.6 Methodological corrections

1.6.1 Thermal output

The 2023 CEP/IRP uses the Aurora PZM model (PZM) in conjunction with the intermediary GHG model to determine how much energy can be retained from CO_2e emitting sources for retail load service. For this Addendum two corrections were made in the PZM:

1. Minimum heat rates in PZM were adjusted for several existing thermal plants (Beaver, Carty, Coyote, and Port Westward 1)
2. The nameplate capacity associated with Beaver was corrected

These corrections altered how those resources are economically dispatched in PZM, and this impacted how much energy is estimated to be retained from CO_2e emitting sources for retail load service. The impact of these changes is shown in **Table 4** which displays differences between the Addendum values and the 2023 CEP/IRP values for CO_2e associated energy retained for retail load service (Reference Case price future (RRRR)). The changes in owned generation, which are primarily changes associated with Beaver, are mostly balanced by market unspecified purchases. In year 2030, the total change in energy retained for retail load service from CO_2e emitting sources is two MWa fewer than in the CEP/IRP.

Table 4. Changes to energy retained for retail load service from CO2e emitting sources

RRRR	Beaver	Carty	Coyote	PW1	PW2	Colstrip (20%)	Market Unspec.	Other	Total
2024	(34)	0	2	(1)	0	0	39	(2)	6
2025	(31)	4	4	1	1	2	25	(0)	5
2026	(18)	5	4	4	1	3	2	0	2
2027	(11)	3	2	2	1	2	1	0	1
2028	11	(2)	(1)	(1)	(1)	(1)	(7)	(1)	(3)
2029	6	(1)	(0)	(1)	(0)	(0)	(5)	(1)	(2)
2030	5	(1)	(0)	(1)	(0)	0	(4)	(1)	(2)

Table 5 shows the annual CO_2e emissions in the Preferred Portfolio from the Addendum and the 2023 CEP/IRP. Note that there is no change in the retail load service CO_2e emissions values (both documents use the same CO_2e glidepaths).

Table 5. CO2e from retail load service and total emissions (retail + wholesale)

All values in million metric tons of CO_2e						
	Retail load CO_2e			Total (retail + wholesale) CO_2e		
Year	2023 CEP/IRP	Addendum	Difference	2023 CEP/IRP	Addendum	Difference
2024	5.31	5.31	0.00	7.17	7.17	0.00
2025	5.05	5.05	0.00	6.91	6.84	(0.07)
2026	4.36	4.36	0.00	6.75	6.63	(0.12)
2027	3.68	3.68	0.00	6.71	6.60	(0.11)
2028	2.99	2.99	0.00	6.71	6.81	0.09
2029	2.31	2.31	0.00	6.43	6.50	0.08
2030	1.62	1.62	0.00	4.42	4.50	0.08

1.6.2 Light load hour market

The 2023 CEP/IRP adequacy model (Sequoia) includes a light load hour market for resource adequacy calculations. The total quantity modeled available from this market varies between 400-999 MW depending on load, with higher load days (which are associated with more extreme weather) seeing less availability than lower load days. The hours that define the light load hour market in the 2023 CEP/IRP were carried over from the 2019 IRP Update and are hour ending 23 to hour ending 6 Pacific Standard Time, Monday through Saturday. However, light load hours are more commonly defined as hour ending 23 to hour ending 6, Prevailing Time.[13] The difference in those two definitions mostly impacts summer adequacy modeling since summer months occur during Pacific Daylight Time (rather than Pacific Standard Time). PGE tested the capacity impact of moving the light load hour market to match Prevailing Time for the months of April through October and saw a 15 MW decrease in summer capacity need and a zero change in winter capacity need, for year 2026.[14] This shift in light load hour market availability was built into this Addendum and only impacts the capacity need values (not the energy need values).[15]

There is a need to better understand power market availability at a more refined level than the traditional heavy load and light load hour split. For example, the Power Council chose to redefine heavy and light load hours for modeling purposes in the 2021 Power Plan due to

[13] Light load hours typically include holidays as well, however holidays are not specified in Sequoia's market setup.
[14] The months of March and November were left in standard time. This was done since adequacy issues in those two months are likely due to cold weather which is more likely in early March or late November, time periods that are mostly in standard time.
[15] The full set of summer years were rerun for this Refresh. The full winter adequacy years were not rerun after test years (reference case years 2026 and 2030) showed zero change. This change only impacts the winter market in October, a month that typically has few (if any) adequacy challenges in the model.

changing market dynamics.[16] For future resource adequacy work, the CEP/IRP team will work internally with market facing teams to discuss which hours market power will most likely be available.

1.6.3 Annual Revenue-requirement Tool

PGE developed its Annual Revenue-requirement Tool (ART) as part of the 2023 CEP/IRP. ART is the final step in the analysis workflow and leverages data from several upstream models including the intermediary GHG model (iGHG). PGE identified an error in the data that is transferred between the iGHG model and ART. Specifically, PGE identified that costs associated with market purchases that are then sold in the wholesale market were not included in the data sent to ART. However, the benefits associated with these wholesale sales on the revenue requirement were included. Thus, previous ART results partially undercounted costs associated with market purchases that remain constant across portfolios with the same decarbonization glidepath.

These unaccounted costs associated with market purchases from both specified and unspecified sources are highest in 2024 and reduce over time as dependence on market purchases that contain emissions reduces in each decarbonization glidepath. Thus, the change in overall revenue requirement is largest in 2024 and reduces over time.

This change does not impact the comparison between portfolios that have the same glidepaths such as the annual price impact comparison between the different energy efficiency portfolios. However, since the change has the highest impact on early years such as 2024 and 2025, the rate of change of the normalized revenue requirement ($/MWh) decreases. In other words, rates increase at a less-steep rate compared to the graphs provided in the filed IRP.

[16] The Power Council, for purposes of the 2021 Power Plan, defined heavy load hours "as hours ending 7 pm through 10 pm on weekdays; light load hours are all others."
https://www.nwcouncil.org/2021powerplan_cost-and-benefits-energy-efficiency-resources/

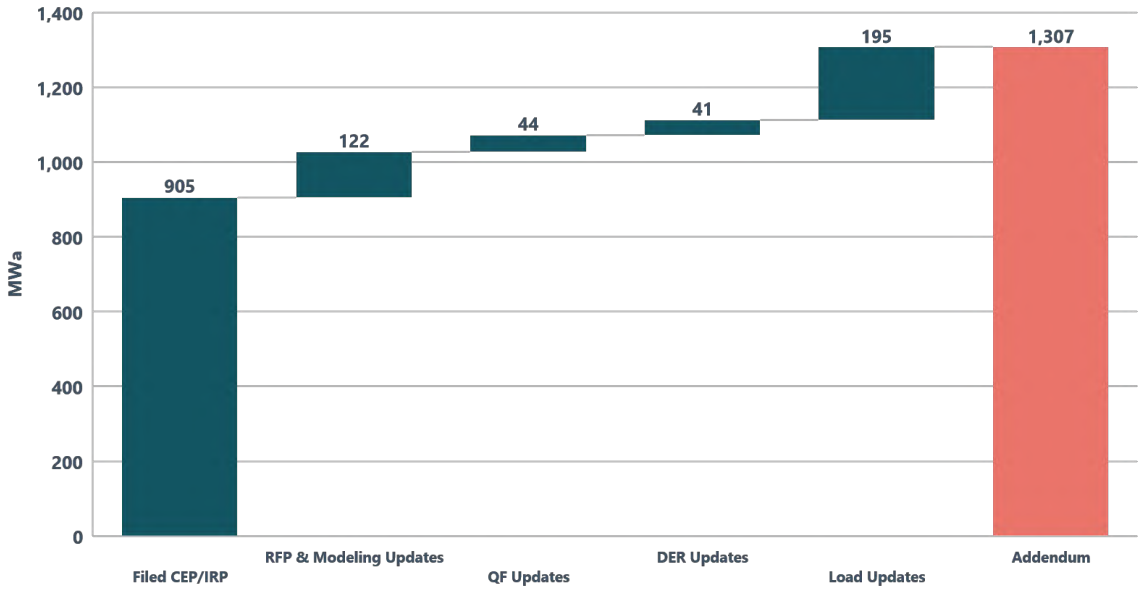
Chapter 2. Need changes

The resulting changes to energy and capacity needs from the updates to input forecasts and modeling changes are described below.

2.1 Energy need

Energy need describes PGE's resource needs in terms of the balance between the average amount of electricity demanded and supplied each year. Since the 2023 CEP/IRP, PGE's estimate of energy need has changed due to updates to the factors described in **Chapter 1, Input updates**.[17] The drivers of change behind each of these updates are described in previous sections. The incremental impact of each update and the resulting updated 2030 Reference Case energy need are shown in **Figure 3**. The combined impact of the updates increases PGE's forecasted 2030 Reference Case energy need from 905 MWa to 1307 MWa.

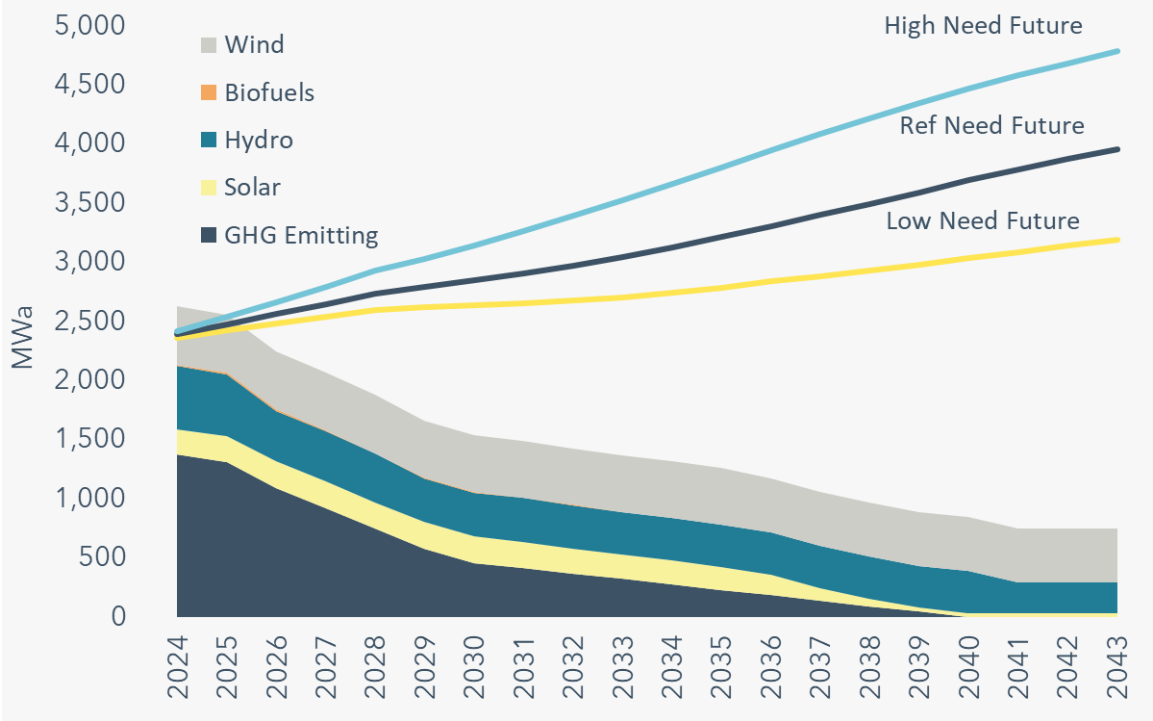
Figure 3. Incremental impacts of updates on 2030 Reference Case energy need



[17] In addition to the changes described in **Chapter 1** an adjustment was made to the forecast of community solar in PGE's energy accounting to improve alignment with PGE's capacity modeling in Sequoia, which resulted in a small increase (1.7 MWa) in 2030.

Figure 4 shows PGE's updated energy-load resource balance, which compares the forecast of Oregon retail load and the amount of energy allowed to serve retail load, assuming a linear decarbonization glidepath. The energy available to serve retail load is the combination of energy from GHG-emitting sources retained for retail sales and the total energy from non-emitting sources. The quantity of allowed energy does not include new supply-side resources outside of those from the 2021 RFP and the continued acquisition of energy efficiency, demand response and other demand-side resources. Before any additional incremental resource additions, Reference Case retail load is expected to surpass the allowed energy on PGE's system starting in 2026.

Figure 4. Energy-load resource balance in linear GHG glidepath in Reference Case future[18]



[18] For convenience of display, the negative energy associated with storage is represented in **Figure 4** as an increase in load.

2.2 Capacity need

Capacity needs describe the effective capacity, in MW, required to achieve a resource-adequate power system. These estimates come from PGE's resource adequacy model, Sequoia.

The impact of the changes that have occurred from when CEP/IRP assumptions were locked to this Addendum is a net increase in the need for resources that provide effective capacity. The elements that create this changing need are broken out for summer and winter in **Figure 5** and **Figure 6** below for the year 2028 (the year targeted by the CEP/IRP Action Plan). Note that some updates impact one season more than the other. For example, moving from 2021 RFP proxies to the actual resources selected reduces the need for winter capacity but has little impact on summer capacity need. For both winter and summer, the largest driver of increased capacity need is the updated load forecast. In 2028, the 1-in-2 peak forecast, on an annual basis, is roughly 250 MW higher in the Addendum than in the CEP/IRP.

Figure 5. Summer 2028, changes in capacity need

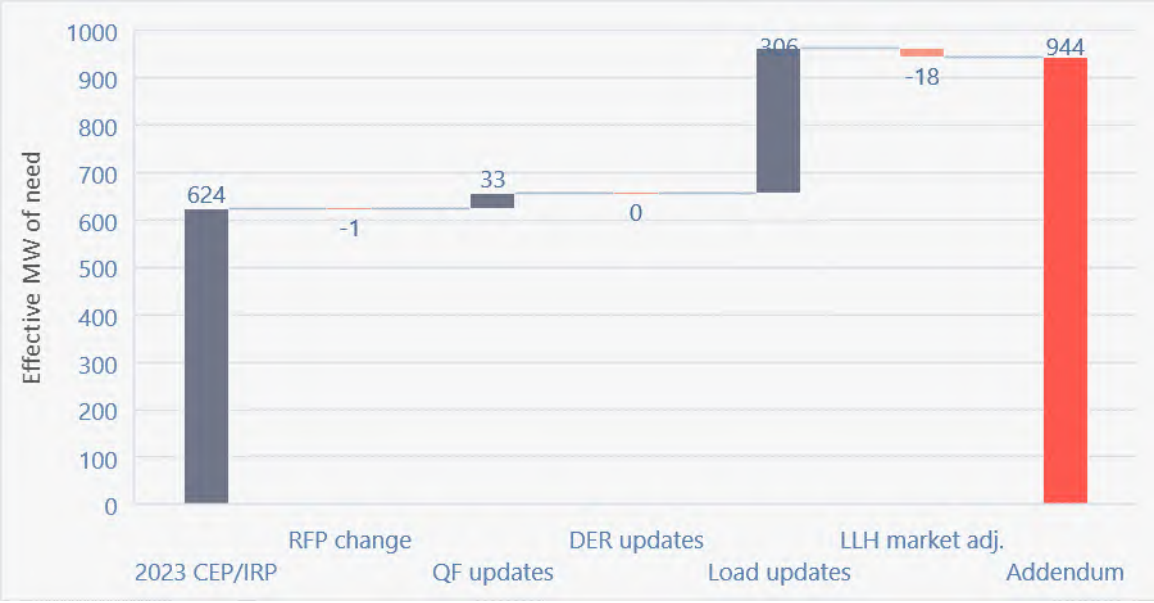


Figure 6. Winter 2028, changes in capacity need

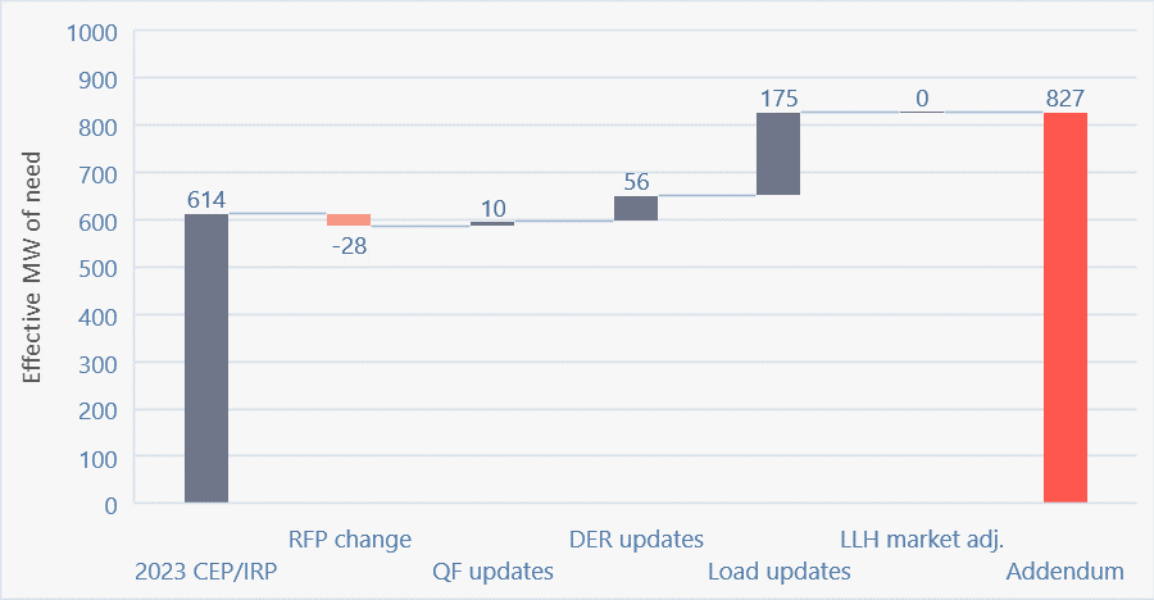
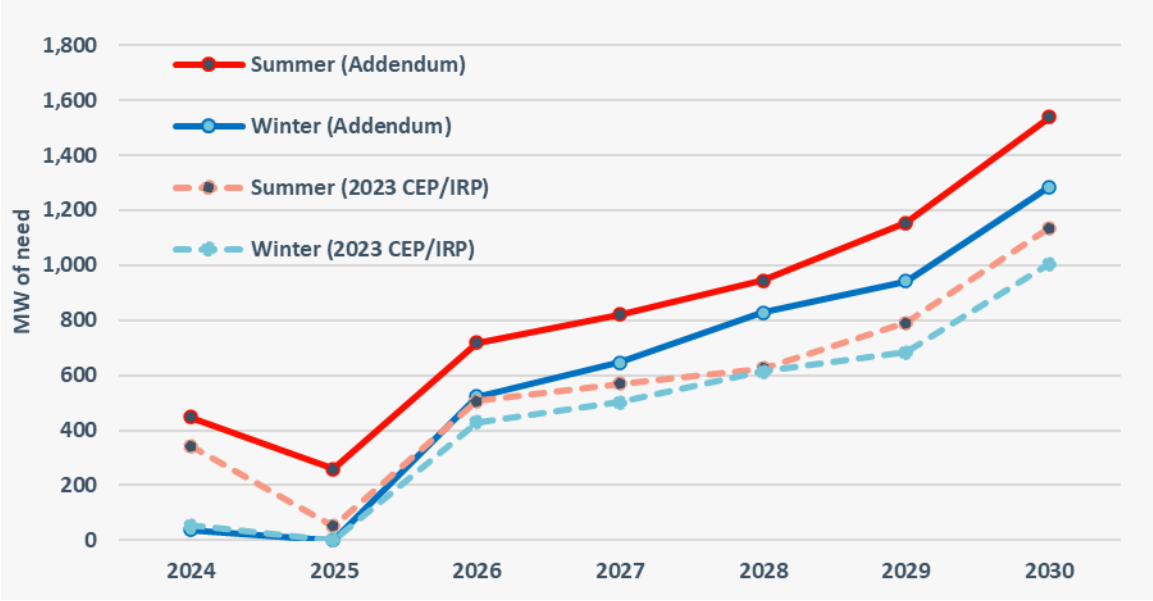


Figure 7 shows the CEP/IRP capacity need and the Addendum values for year 2024 through 2030. Need increases over time due to load growth, contract expirations, and resource exits. Need increases sharply in 2026 due to expiring contracts, and again in 2030 due to the assumption that PGE will stop taking power from Colstrip at the end of 2029.

Figure 7. Capacity need comparison



Chapter 3. Portfolio analysis

PGE reevaluated portfolio analysis based on the updated estimates of need provided in **Chapter 2, Need changes** and methodological change described in **Section 1.6, Methodological corrections**. Additionally, we made two portfolio analysis corrections discussed earlier in the CEP/IRP docket.[19] The changes to portfolio analysis are described below, then the results to all changed inputs to all modeled portfolios and the Preferred Portfolio follow after.

3.1 Hybrid and pumped storage resources

As mentioned in PGE's Round 0 comments, PGE has identified (with the help of RNW and Swan Lake and Goldendale) two corrections to make in portfolio analysis.

The first correction addresses the failure to make pumped hydro storage available for selection in the Preferred Portfolio. PGE agrees that pumped hydro should not be included as an emerging technology and has made it available for selection in the Preferred Portfolio in this refreshed analysis. In this analysis, the full 2000 MW of known potential projects in the region (Swan Lake 400 MW, Gordon Butte 400 MW and Goldendale 800 MW) is made available for selection in the Preferred Portfolio starting in 2028.

The second correction addresses an error in the capacity factors of hybrid resources (solar plus storage) used in portfolio analysis in the filed CEP/IRP. The error, which only affected hybrid resources, resulted in capacity factors that were 33 percent to 40 percent of what they should have been. As a result, the potential energy benefits of hybrid resources were underestimated in modeling. This refresh of portfolio analysis uses the corrected hybrid capacity factors. **Table 6** shows both the corrected capacity factors, used in this analysis, and the capacity factors used in the filed 2023 CEP/IRP.

Table 6. Average annual capacity factors of hybrid proxy resources

	Update (corrected)	Filed CEP/IRP (with error)
Christmas Valley Hybrid 1	28.6%	9.5%
Christmas Valley Hybrid 2	29.2%	11.7%
McMinnville Hybrid 1	22.3%	7.4%
McMinnville Hybrid 2	23.0%	9.2%

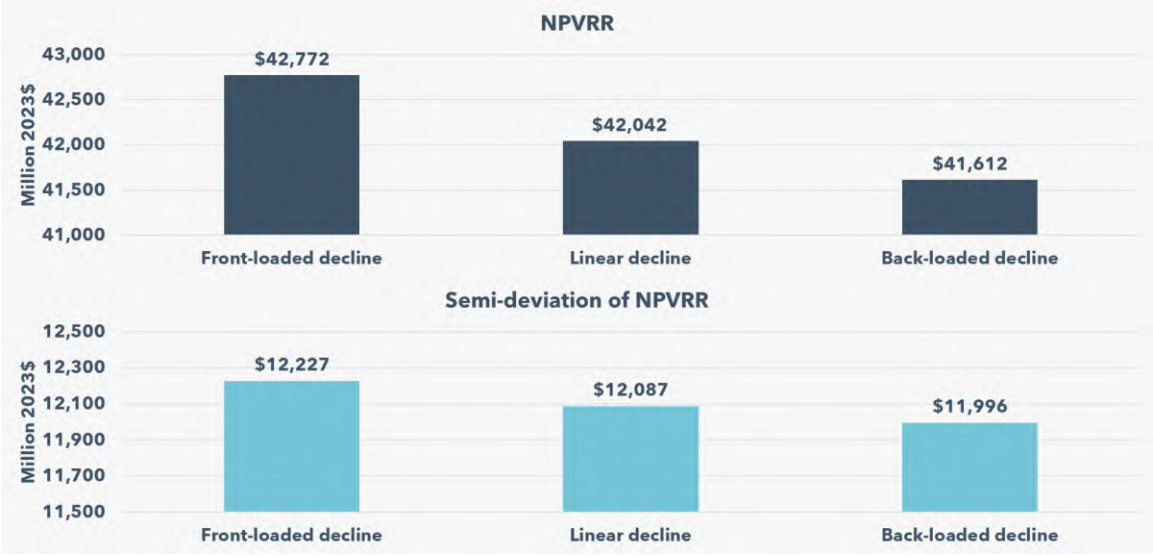
[19] See Section 3.6, Pumped hydro characteristics and Section 11.6, Hybrid resources of PGE's Round 0 comments. Available here: https://edocs.puc.state.or.us/efdocs/HAC/lc80hac102443.pdf

3.2 Portfolio analysis

Portfolio analysis in the 2023 CEP/IRP was organized around several key questions in resource planning. After incorporating the updated input forecasts, the findings regarding those key questions are robust to the updates and have not changed.

Decarbonization glidepath: Refreshing estimates of system needs provides supporting evidence that the linear decline still represents the best balance between decarbonization and portfolio cost and risks. Comparison of the cost and risk metrics of the decarbonization glidepath portfolios shows that, consistent with the results in the filed CEP/IRP, the cost and risk of the 'Linear decline' portfolio falls in between those of the 'Front-loaded decline' and 'Back-loaded decline' portfolios (**Figure 8**). While the back-loaded decline produces lower portfolio cost and risk metrics, it still has drawbacks associated higher cumulative emissions and procurement risk from waiting to procure the resources necessary for HB 2021 compliance. Conversely, while the front-loaded decline produces lower cumulative emissions, it brings higher costs than the linear glidepath.

Figure 8. Cost and risk metrics of decarbonization glidepath portfolios



Transmission need: Increasing system resource need exacerbates the need for transmission to move off-system generation to load. The informational portfolio with no transmission upgrades ('No Upgrades') displays the estimated first year where PGE would not be able to

add sufficient resources without some increase in transmission availability.[20] This date is displayed in **Table 7** which compares the 'No Upgrade' portfolio results from the filed CEP/IRP to the updated results. The first year of transmission need has shifted from 2029 to 2028, and the size of the need in 2030 has increased from 768 MW to 1,658 MW.

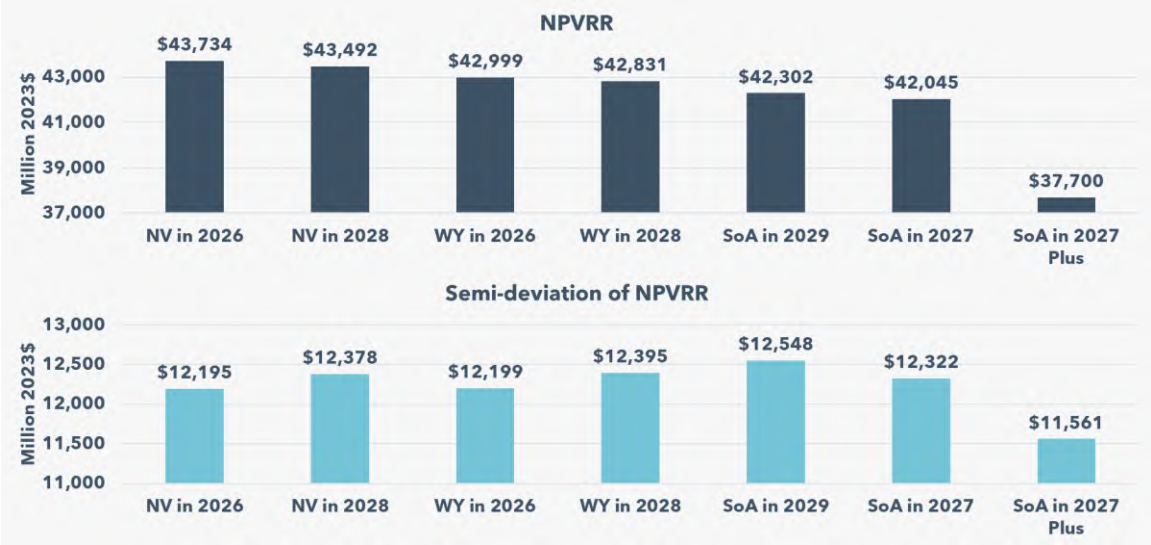
Table 7. Estimated Reference Case transmission need

	Estimated transmission need (MW)	
Year	**2023 CEP/IRP**	**Updated Results**
2026	0	0
2027	0	0
2028	0	355
2029	159	1,051
2030	768	1,658
2035	3,005	4,568
2040	7,468	9,403

Additional Transmission Resources: Having access to a wider geographic area of resources leads to decreased cost and risk. Consistent with the findings in the filed CEP/IRP, the 'SoA in 2027 plus' portfolio, which allows access to the largest amount of transmission resources, produces the lowest cost and risk amongst the transmission timing portfolios (**Figure 9**). These results demonstrate the benefits of having more transmission options available. Both 'SoA in 2027' and 'SoA in 2029' have lower cost than the WY and NV transmission expansion portfolios, reinforcing the finding of value in pursuing options to upgrade the existing transmission system to expand access to renewable resources in the PNW. These findings reaffirm the inclusion of all available transmission options in the Preferred Portfolio.

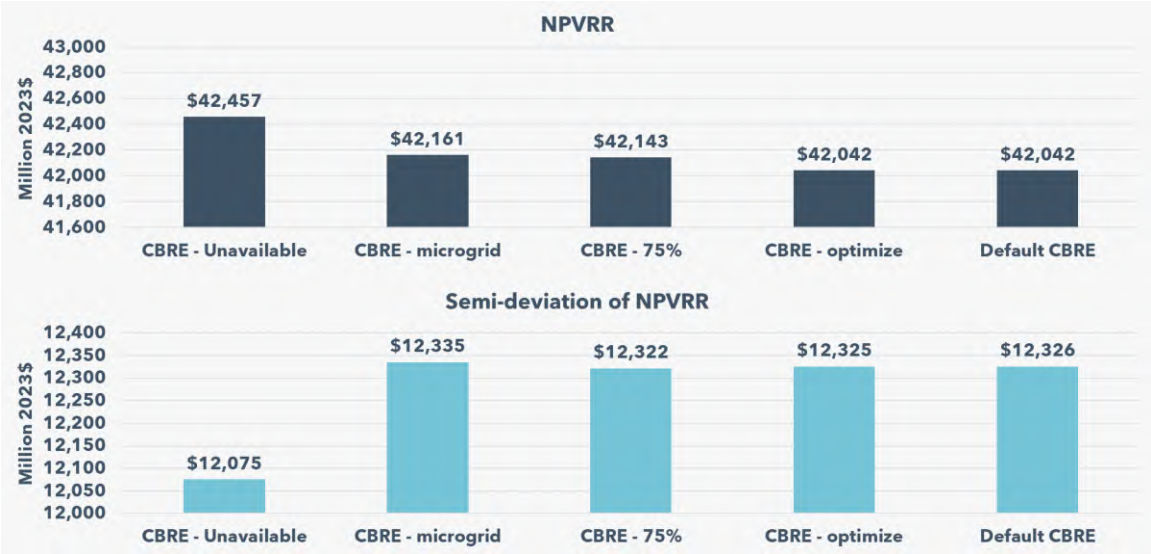
[20] The portfolio is considered informational because it does not represent an actionable set of resource actions for PGE. It does provide a useful demonstration that the current forecasts of transmission capacity are insufficient to meet system needs.

Figure 9. Cost and risk metrics of transmission timing portfolios



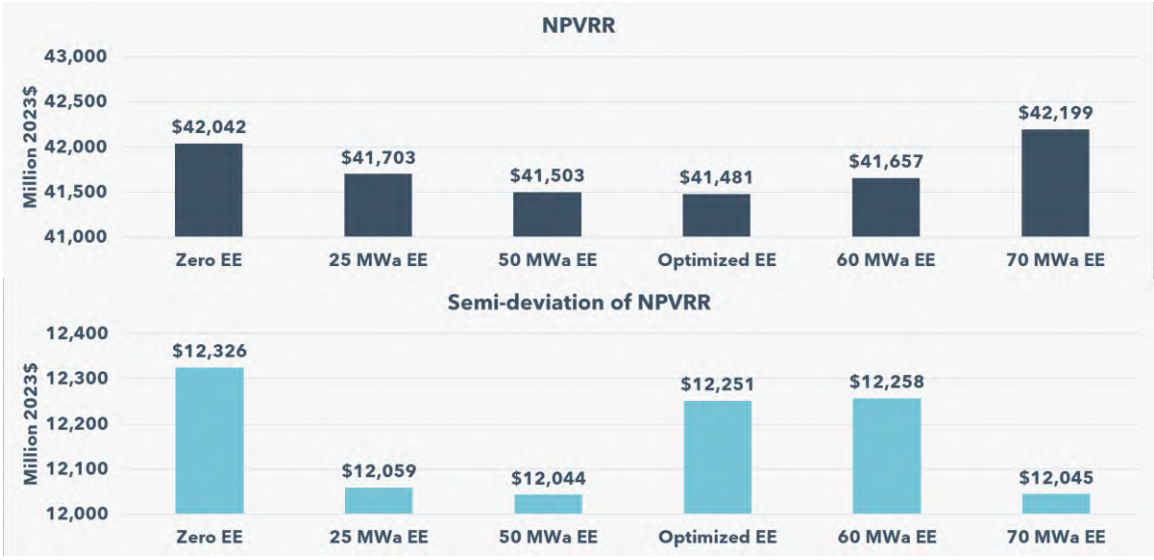
Community-Based Renewable Energy: The addition of CBREs to PGE's system lower portfolio cost and the full potential of 155 MW are added when the model is able to optimize their selection. Consistent with findings in the filed CEP/IRP, the 'CBRE – optimize' and 'Default CBRE' portfolios, which both add the full 155 MW of CBRE resources, produce the lowest costs. This finding demonstrates potential for CBREs to lower costs in a transmission-constrained environment, while maximizing the provision of community benefits (**Figure 10**). Consistent with these updated results, the full 155 MW of CBREs are included in the Preferred Portfolio.

Figure 10. Cost and risk metrics of CBRE portfolios



Energy Efficiency: The increased need increases the value of non-emitting generation resources. As in the filed CEP/IRP, additional quantities of EE can lower long-term cost and risk. The optimized EE portfolio elects to add 53 MWa of additional EE. As shown in **Figure 11**, increasing the amount of EE added decreases costs up to a point, suggesting that there are additional quantities of EE beyond those identified as cost-effective using avoided cost outputs from the 2019 IRP update that can help meet energy needs while lowering long-term portfolio costs.

Figure 11. Cost and risk metrics of EE & DR portfolios



However, as detailed in the filed CEP/IRP there are near-term cost impact implications associated with EE that must be taken into consideration. **Figure 12** shows that relative to a portfolio without any additional EE, including additional EE results in higher near-term cost pressure. PGE notes that the increase in dependence on both transmission market access resources and generic resource because of higher resource needs, reduce the relative increase in near term cost stemming from energy efficiency. Thus, compared to the analysis that was filed in the CEP/IRP, we see a smaller increase in near-term cost especially in 2029 and 2030. Since the underlying phenomenon that ties the addition of EE to increase near term rate pressure is policy based, the directional insights do not vary from the filed CEP/IRP. Reiterating the policies that drive this interaction, first, unlike other assets the additional EE is not financed or securitized, so the full cost is incurred before the generation starts. Second, EE decreases retail sales which leads to increased costs per unit of sales. Aggregated, these two effects lead to much higher near-term cost increases than the relevant comparators. While these policies have been in place for many years, the fast ramp in acquisition required exacerbates the near-term impacts of these policies. PGE recognizes that different rate mechanisms could reduce the influence of the near-term price impact. As a result of the

findings, the Preferred Portfolio does not include additional EE beyond the amount found to be cost-effective using avoided cost outputs developed from the 2019 IRP.

Figure 12. Yearly costs per MWh for additional EE portfolios

3.3 Preferred Portfolio

The cumulative resource additions from 2024 through 2030 in the Preferred Portfolio are shown in **Table 8**. Notable outcomes of the resource build include:

- The updates to energy and capacity need forecasts resulted in a larger resource build (and associated cost and risk metrics) in the Preferred Portfolio.
- The correction to hybrid capacity factors has resulted in the model shifting to selecting hybrid resources rather than standalone storage and solar. 1010 MW of hybrid resources are added through 2030.
- All 800 MW of available transmission expansion are selected by 2030. This includes 400 MW of WY wind and 400 MW of NV solar.

- The model must now rely on 251 MW of the Generic VER resource in 2030 to meet needs.
- Pumped hydro storage is not added in the 2024-2030 timeframe. The full 2000 MW of available pumped hydro are added in 2040.

Table 8. Cumulative resource buildout in Preferred Portfolio (MW)

	2024	2025	2026	2027	2028	2029	2030
Wind	0	0	690	1090	1128	1528	1528
Solar	0	0	0	0	0	153	400
Hybrid	0	0	299	299	869	1010	1010
Battery Storage	0	0	0	0	0	0	0
Pumped Hydro Storage	0	0	0	0	0	0	0
CBREs	0	0	66	85	110	133	155
WY Tx	0	0	0	0	0	400	400
NV Tx	0	0	0	0	0	153	400
Generic VER	0	0	0	0	0	0	251
SoA Tx	0	0	0	400	400	400	400
Additional EE & DERs	0	0	0	0	0	0	0
Non-GHG-Emitting Contract Extension	0	0	200	200	200	200	200
Cost-effective EE (MWa)*	30	60	90	120	150	183	216
Cost-effective DR*	133	162	183	199	211	218	228
Clearwater Wind **	311	311	311	311	311	311	311
Seaside Storage **	0	0	200	200	200	200	200
Troutdale Storage **	0	200	200	200	200	200	200
Evergreen Storage **	0	75	75	75	75	75	75

***** Contributions reduce need
****** 2021 RFP resources

The cost and risk metrics of the Preferred Portfolio are displayed in **Figure 13**. The increased need and resulting increase in resource additions resulted in an increase in cost and risk associated with the Preferred Portfolio. The 20-year NPVRR of the Preferred Portfolio in the updated results is $36.96 billion. The increased resource needs found in the results of this analysis using updated need forecasts reinforces the key findings from the filed CEP/IRP that the binding nature of decarbonization and transmission constraints necessitates an approach to pursue all feasible avenues of resource additions.

Figure 13. Cost and risk metrics of the Preferred Portfolio

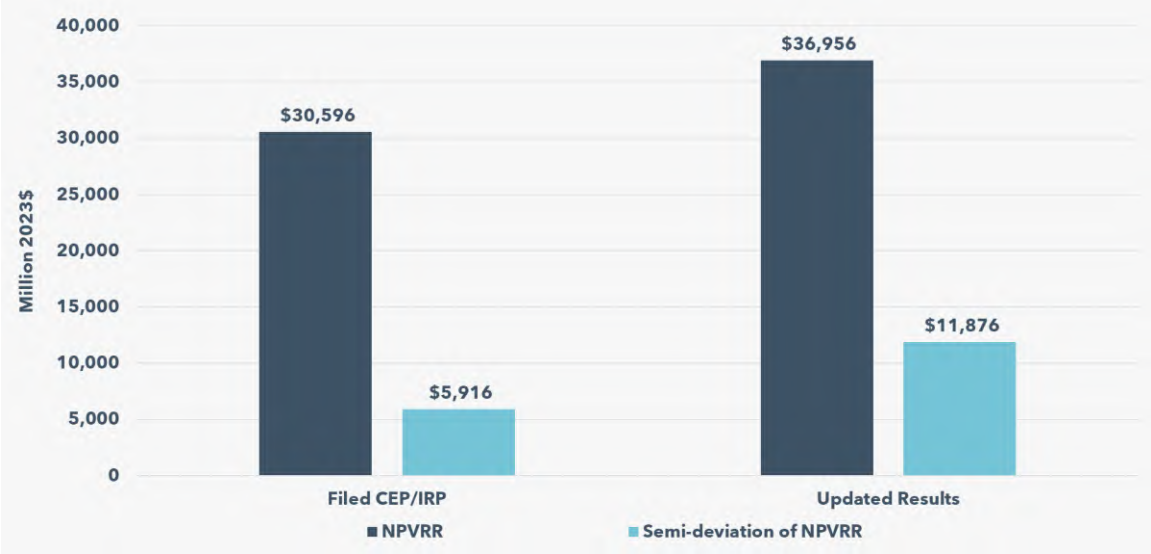


Figure 14 shows the difference in annual price impact between the Preferred Portfolio that was filed in CEP/IRP and the Preferred Portfolio developed in this Addendum. The increase in costs across the years is the direct result of the increase in resource additions stemming from the increased resource need driven by the different factors identified in **Chapter 2, Need changes**.[21,22]

Figure 14. Price impact difference between filed CEP/IRP and Addendum Preferred Portfolio

[21] The methodological correction identified in **Section 1.6.3** is addressed and factors within the **Figure 14**. However, its impact is minor relative to the change in price impact resulting from the addition of new resources

[22] The reduction in cost in 2040 is a function of the large addition of batteries, which based on the current treatment of the 30% ITC, lowers the first year's cash flow. The associated large range highlights the relationship between ownership structures and tax credits as they affect cash flows.

Table 9 is an update of Table 2 of the filed CEP/IRP, providing a summary of total resource actions from 2023 through 2030. It shows incremental new resources added by year (it does not show resource losses). It includes IRP Preferred Portfolio resources and non-CEP/IRP resource actions (2021 RFP resources, qualifying facility resource additions, GFI solar additions, etc.).[23] **Table 9** also include PGE's retail load service GHG emissions glidepath from 2023 through 2030.

Table 9. Preferred Portfolio resource pathway through 2030 (incremental additions)

Values in nameplate MW	2023	2024	2025	2026	2027	2028	2029	2030
DR (cost-effective)	24	26	25	19	14	11	8	9
EE (cost-effective)	31	30	30	30	30	31	33	33
Storage	0	0	275	200	0	0	0	0
Solar & wind	30	734	69	700	410	48	563	508
Hybrid	0	0	0	299	0	570	141	0
CBRE	0	0	0	66	19	25	23	22
Transmission (Tx) market access	0	0	0	0	0	0	553	247
Contract extension	0	0	0	200	0	0	0	0
GHG glidepath (MMTCO2e)	5.9	5.3	5.0	4.4	3.7	3.0	2.3	1.6

Table 10 shows incremental resource actions from year 2031 through 2043. It also includes PGE's retail load service GHG emissions glidepath from 2031 through 2043.

Table 10. Preferred Portfolio resource pathway 2031-2043 (incremental additions)

Values in nameplate MW	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
DR (cost effective)	11	8	9	8	5	11	7	7	7	1	6	11	3
EE (cost effective)	34	34	32	31	29	28	25	23	19	16	15	11	9
Storage	0	32	100	100	100	100	68	100	100	2100	0	0	0
Solar & wind	522	347	341	363	469	500	500	500	500	500	483	255	225
Hybrid	0	0	0	0	0	0	0	0	0	0	0	0	0
CBRE	0	0	0	0	0	0	0	0	0	0	0	0	0
Tx market access	0	0	0	0	0	0	0	0	0	0	0	0	0
Capacity	0	0	0	18	134	135	256	500	500	500	0	0	0
GHG glidepath (MMT CO2e)	1.5	1.3	1.1	1.0	0.8	0.6	0.5	0.3	0.2	0.0	0.0	0.0	0.0

[23] As a result of including non-CEP/IRP and non-RFP resources the values in this table will differ from those in **Table 8**. For simplification purposes, generic VER resources and 5 MW of qualifying facility biomass are included in the wind & solar values.

Conclusion

This Addendum has incorporated several updated CEP/IRP input forecasts and reevaluated portfolio analysis on the resulting calculations of system need. Results have provided additional support to the answers proposed to the main questions posed by portfolio analysis:

- A linear decline is an appropriate method to model emission reductions through 2030
- Addressing congestion across BPA's system (especially across the South of Allston flowgate) is necessary to maintain reliability and add sufficient off-system resources to meet energy needs
- Acquiring generation beyond the traditional geographical footprint of PGE's resources is an effective strategy to reduce long-term system cost and risk, particularly in higher-need futures
- CBRE resources could be an effective means of reducing long-term system cost, risk, and emissions while maximizing community benefits
- Additional quantities of EE (above the cost-effective forecasts from the ETO) reduce long-term system cost and risk. However, under the current policy and cost structures this additional EE has a significant near-term price impact.

The increased resource need could warrant updating the resource acquisition targets in the Action Plan. Those potential updated values are presented below in **Table 11**:

Table 11. Potential updates to Action Plan resource targets

		2023 CEP/IRP	LC 80 Addendum
Customer actions	Acquire all cost-effective energy efficiency	150MWa Cumulative 2024-2028	Unchanged
	Incorporate customer demand response	211 MW summer & 158 winter by 2028	Unchanged
CBRE action	Issue RFP for all available and qualifying CBRE resources	66 MW by 2026	Unchanged
Energy action	Conduct one or more RFPs to acquire sufficient energy to position PGE to meet the forecasted 2030 need	181 MWa (905 MWa / 5 total years) per year through 2028 (543 MWa in Action Plan window)	**261** MWa (**1307** MWa / 5 total years) per year through 2028 (**783** MWa in Action Plan window)
Capacity action	Conduct one or more RFPs to acquire sufficient capacity to meet forecasted 2028 needs	624 MW summer & 614 MW winter	**944** MW summer & **827** MW winter

		2023 CEP/IRP	LC 80 Addendum
Transmission actions	Pursue options to alleviate congestion on the South of Alston (SoA) flowgate	n/a	Unchanged
	Explore options to upgrade the Bethel-Round Butte line (from 230 to 500 kV)	n/a	Unchanged

These resource targets in the Action Plan form the basis of need projections going forward. However, this Addendum supports the notion that resource need estimates are not static. Instead, they will be constantly updated throughout the LC 80 docket and beyond as new input forecasts, resource information, and methodological changes are incorporated. This is especially applicable for the current RFP, whose resource acquisition targets will be updated with refreshed forecasts of system needs going forward. This constant updating is not a new process: the capacity needs used in the 2021 All-Source RFP were updated six times either between its initiation (April 2021) and its last filing (May 2022) in the RFP docket (UM 2166) and other regulatory filings. These updates were triggered by updated input forecasts like updated load forecasts and projected resource changes (such as the extension of the Pelton-Round Butte contract). The results of the 2023 CEP/IRP were an important but static consideration in how the Company plans to meet its long-term system needs. However, PGE expects the forecasts of long-term supply and demand that create system need to be continuously evolving, and the Company is committed to working with its public stakeholders and the Commission to continue updating forecasts when and where appropriate.

PGE also recognizes that there remain important questions in resource planning that warrant further investigation in the LC 80 docket. The Company is working to clearly articulate its long-term transmission needs and how the transmission components of the Action Plan fit in to its wider resource acquisition strategy. PGE is also looking to assess what options exist to leverage the opportunities of additional EE beyond the forecasted acquisition of cost-effective measures provided by ETO.

These questions highlight the challenge of acquiring sufficient resources to meet HB 2021's emission reduction targets both reliably and affordably. PGE is committed to working with its public stakeholders and the Commission to determine the best set of resources to achieve those three goals. This Addendum reflects our willingness to ensure this conversation is supported by the most appropriate information possible.

Portland General Electric (PGE)

Clean Energy Plan and Integrated Resource Plan 2023

CEP Data Template

Purpose: **This spreadsheet contains supporting data for PGE's portfolio analysis for the 2023 Clean Energy Plan (CEP) and Integrated Resource Plan (IRP). For accessibility and in compliance with OPUC Order 22-446, the data is provided in a standard format provided by Public Utility Commission of Oregon (OPUC) Staff.**

Location: **A Microsoft Excel version of this document is available on PGE's website at www.portlandgeneral.com/resourceplanning/**

The Excel version contains cell comments and notes that provide context to data provided that may not be visible in the filed version.

Contents:

1... Data Template Description
2... Portfolios
3... Annual Goals for Actions
4... Annual Greenhouse Gas (GHG) Impacts of Actions
5... Annual Community Benefits Indicator (CBI) Impacts of Actions
6... Portfolio Scoring
7... Additional Transparency Items
8... GHG Emissions
9... Fossil Fuel Operations
10... Annual Costs
11... RECs

Contact: **For general inquiries or accessibility questions, please contact CEP@pgn.com**
For all formal correspondence or inquiries related to PGE's CEP/IRP filing, please contact pge.opuc.filings@pgn.com

Vintage: **Updated 7/7/2023**

Based on: **DRAFT CEP/IRP Data Template**
Received from OPUC Staff on 2/24/23

DRAFT CEP/IRP Data Template

Template vintage (OPUC Staff): 2/22/2023

Background

This spreadsheet provides a standard data sharing template for non-confidential information pertaining utility Clean Energy Plans (CEPs) and Integrated Resource Plans (IRPs), as described in OPUC Orders Orders No. 22-206, No. 22-390, and No. 22-446. This template accompanies a complete list of the requirements and expectations from Orders No. 22-206, No. 22-390, and No. 22-446 (**"UM 2225 Order Summary/Rubric"**) and the information requested in this data template is cross-referenced to the items listed in the UM 2225 Order Summary/Rubric at the top of each tab.

Units

Information is requested in the following standard units to enable efficient review by OPUC Staf and stakeholders:

Data	**Units**
Capacity	MW
Energy	GWh, MWh, or MWa
GHG Emissions	metric tons $CO2_e$
Fuel burn	MMBtu
Costs	nominal $ or million nominal $

For some items, including Community Benefits Indicators (CBIs) and Scoring Metrics, the utility must provide the units that they use in their plans.

Legend

Provide data on a forecasted or planning basis
Provide historical data
Provide units, metric, or resource name

Instructions

Fill in the requested information, with units if not already specified.

If providing information for more than 30 portfolios (see Portfolios tab), copy or expand tables as needed

Email questions to:

Submission instructions:

Instructions

List the set of portfolios considered in developing the **Action Plan**, which test different paces of GHG reductions and different levels of community impact.

Identify the Preferred Portfolio in cell B5

Preferred Portfolio	Portfolio40	Preferred Portfolio
Index	Portfolio list	
1	Portfolio1	Linear decline
2	Portfolio2	Front-loaded decline
3	Portfolio3	Back-loaded decline
4	Portfolio4	100% emissions reduction by 2035
5	Portfolio5	2-yr forward shift in targets
6	Portfolio6	Optimize NCE
7	Portfolio7	Zero NCE
8	Portfolio8	60 MWa EE
9	Portfolio9	Default CBREs
10	Portfolio10	CBRE - 75%
11	Portfolio11	CBRE - zero
12	Portfolio12	CBRE - microgrid
13	Portfolio13	CBRE - optimize
14	Portfolio14	Unconstrained Tx
15	Portfolio15	No Upgrades
16	Portfolio16	Unconstrained SoA
17	Portfolio17	Unconstrained SoA Plus
18	Portfolio18	SoA in 2027
19	Portfolio19	SoA in 2029
20	Portfolio20	WY in 2026
21	Portfolio21	NV in 2026
22	Portfolio22	WY in 2028
23	Portfolio23	NV in 2028
24	Portfolio24	Oregon-only resources
25	Portfolio25	Physical RPS
26	Portfolio26	Hydrogen blending
27	Portfolio27	Hydrogen building
28	Portfolio28	Offshore wind
29	Portfolio29	Long Duration Storage
30	Portfolio30	Pumped hydro
31	Portfolio31	RTO
32	Portfolio32	Min Avg LT cost
33	Portfolio33	Min Avg ST cost
34	Portfolio34	Min Ref ST cost
35	Portfolio35	SoA in 2027 Plus
36	Portfolio36	50 Mwa EE
37	Portfolio37	25 Mwa EE
38	Portfolio38	70 Mwa EE
39	Portfolio39	Optimized
40	Portfolio40	Preferred

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual goals for actions over the study period

UM 2225 Order Summary/Rubric references: C.2(a)-(i), C.3

	40	Portfolio40	Preferred											
		Clean energy resources (MWa)	Clean energy resources (MWa)	Energy Storage (MW)	Energy Storage (MWh)	Energy Storage (MW)	Energy Storage (MWh)	Energy Efficiency (MWa)	Demand Response (MW)	CBREs (MWa)	CBREs (MW or MWa)		Transmission Projects	
Year		System resources	Voluntary programs	System resources	System resources	Voluntary programs	Voluntary programs			System resources	Voluntary programs	Retirements (list unit)	(MW)	Operational Changes
2023		n/a	85.49	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2024		138.60	112.47	-	-	n/a	n/a	30.00	133.00	-	n/a	n/a	-	n/a
2025		138.61	113.21	475.00	1,900.00	n/a	n/a	60.00	162.00	-	n/a	n/a	-	n/a
2026		618.32	114.47	475.00	1,900.00	n/a	n/a	90.00	183.00	12.55	n/a	n/a	-	n/a
2027		791.80	115.74	475.00	1,900.00	n/a	n/a	120.00	199.00	16.01	n/a	n/a	400.00	n/a
2028		972.18	116.89	475.00	1,900.00	n/a	n/a	150.00	211.00	21.57	n/a	n/a	400.00	n/a
2029		1,237.95	118.28	475.00	1,900.00	n/a	n/a	183.00	218.00	26.76	n/a	n/a	953.00	n/a
2030		1,407.89	119.55	475.00	1,900.00	n/a	n/a	216.00	228.00	30.78	n/a	n/a	1,200.00	n/a
2031		1,516.55	119.04	475.00	1,900.00	n/a	n/a	251.00	242.00	30.79	n/a	n/a	1,200.00	n/a
2032		1,645.97	118.41	507.00	2,028.00	n/a	n/a	285.00	252.00	30.80	n/a	n/a	1,200.00	n/a
2033		1,777.25	118.02	607.00	2,428.00	n/a	n/a	317.00	261.00	30.80	n/a	n/a	1,200.00	n/a
2034		1,913.68	117.52	707.00	2,828.00	n/a	n/a	348.00	270.00	30.80	n/a	n/a	1,200.00	n/a
2035		2,099.53	117.01	807.00	3,228.00	n/a	n/a	377.00	272.00	30.80	n/a	n/a	1,200.00	n/a
2036		2,288.45	116.40	907.00	3,628.00	n/a	n/a	404.00	287.00	30.80	n/a	n/a	1,200.00	n/a
2037		2,478.73	67.75	975.00	3,900.00	n/a	n/a	429.00	296.00	30.80	n/a	n/a	1,200.00	n/a
2038		2,667.63	41.47	1,075.00	4,300.00	n/a	n/a	452.00	303.00	30.80	n/a	n/a	1,200.00	n/a
2039		2,858.10	16.93	1,175.00	4,700.00	n/a	n/a	471.00	310.00	30.80	n/a	n/a	1,200.00	n/a
2040		3,047.24	16.93	3,275.00	25,100.00	n/a	n/a	487.00	306.00	30.80	n/a	n/a	1,200.00	n/a
2041		3,232.18	16.93	3,275.00	25,100.00	n/a	n/a	503.00	314.00	30.80	n/a	n/a	1,200.00	n/a
2042		3,329.05	16.93	3,275.00	25,100.00	n/a	n/a	514.00	330.00	30.80	n/a	n/a	1,200.00	n/a
2043		3,413.94	16.93	3,275.00	25,100.00	n/a	n/a	523.00	336.00	30.80	n/a	n/a	1,200.00	n/a
sources:		Preferred portfolio summary: wind, solar, hybrid, hydrogen, Clearwater Wind, generic VER, contract extension	Annual Resource Availability: Green Future Initiative (Bakeoven, Daybreak/Bakeoven2, Montague) + Community Solar MWa	Preferred portfolio summary: 4hr battery as storage + 4hr battery RFP proxy	MWh discharged: Energy Storage MW *storage duration	n/a	n/a	Preferred portfolio summary: EE	Preferred portfolio summary: DR	Preferred portfolio summary: Solar, micro, hydro CBRE	n/a	n/a	Preferred portfolio summary: SoA+ market access	n/a

	1	Portfolio1	Linear decline											
		Clean energy resources (MWa)	Clean energy resources (MWa)	Energy Storage (MW)	Energy Storage (MWh)	Energy Storage (MW)	Energy Storage (MWh)			CBREs (MWa)	CBREs (MW or MWa)			
Year		System resources	Voluntary programs	System resources	System resources	Voluntary programs	Voluntary programs	Energy Efficiency (MWa)	Demand Response (MW)	System resources	Voluntary programs	Retirements (list unit)	Transmission Projects (MW)	Operational Changes
2023		n/a	85.49	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2024		138.60	112.47	-	-	n/a	n/a	30.00	133.00	-	n/a	n/a	-	n/a
2025		138.61	113.21	475.00	1,900.00	n/a	n/a	60.00	162.00	-	n/a	n/a	-	n/a
2026		633.42	114.47	475.00	1,900.00	n/a	n/a	90.00	183.00	12.55	n/a	n/a	-	n/a
2027		734.27	115.74	475.00	1,900.00	n/a	n/a	120.00	199.00	16.01	n/a	n/a	228.00	n/a
2028		972.18	116.89	475.00	1,900.00	n/a	n/a	150.00	211.00	21.57	n/a	n/a	400.00	n/a
2029		1,237.96	118.28	475.00	1,900.00	n/a	n/a	183.00	218.00	26.77	n/a	n/a	400.00	n/a
2030		1,412.73	119.55	816.00	3,264.00	n/a	n/a	216.00	228.00	30.80	n/a	n/a	400.00	n/a
2031		1,522.55	119.04	916.00	3,664.00	n/a	n/a	251.00	242.00	30.80	n/a	n/a	400.00	n/a
2032		1,651.95	118.41	916.00	3,664.00	n/a	n/a	285.00	252.00	30.80	n/a	n/a	400.00	n/a
2033		1,781.48	118.02	916.00	3,664.00	n/a	n/a	317.00	261.00	30.80	n/a	n/a	400.00	n/a
2034		1,916.63	117.52	916.00	3,664.00	n/a	n/a	348.00	270.00	30.80	n/a	n/a	400.00	n/a
2035		2,075.03	117.01	916.00	3,664.00	n/a	n/a	377.00	272.00	30.80	n/a	n/a	400.00	n/a
2036		2,264.40	116.40	916.00	3,664.00	n/a	n/a	404.00	287.00	30.80	n/a	n/a	400.00	n/a
2037		2,454.08	67.75	975.00	3,900.00	n/a	n/a	429.00	296.00	30.80	n/a	n/a	400.00	n/a
2038		2,631.79	41.47	1,075.00	4,300.00	n/a	n/a	452.00	303.00	30.80	n/a	n/a	400.00	n/a
2039		2,811.35	16.93	1,175.00	4,700.00	n/a	n/a	471.00	310.00	30.80	n/a	n/a	400.00	n/a
2040		2,960.40	16.93	1,275.00	5,100.00	n/a	n/a	487.00	306.00	30.80	n/a	n/a	400.00	n/a
2041		3,145.01	16.93	1,275.00	5,100.00	n/a	n/a	503.00	314.00	30.80	n/a	n/a	400.00	n/a
2042		3,232.38	16.93	1,275.00	5,100.00	n/a	n/a	514.00	330.00	30.80	n/a	n/a	400.00	n/a
2043		3,320.52	16.93	1,275.00	5,100.00	n/a	n/a	523.00	336.00	30.80	n/a	n/a	400.00	n/a

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual goals for actions over the study period

UM 2225 Order Summary/Rubric references: C.2(a)-(i), C.3

								Note: This column reflects both the EE that was previously deemed cost effective by Energy Trust and any additional EE selected in this portfolio	Note: this column reflects both the DR that was previously deemed cost effective by PGE and any additional DR selected in this portfolio					
2	Portfolio2	Front-loaded decline								CBREs (MWa)	CBREs (MW or MWa)			
Year	Clean energy resources (MWa) System resources	Clean energy resources (MWa) Voluntary programs	Energy Storage (MW) System resources	Energy Storage (MWh) System resources	Energy Storage (MW) Voluntary programs	Energy Storage (MWh) Voluntary programs	Energy Efficiency (MWa)	Demand Response (MW)	System resources	Voluntary programs	Retirements (list unit)	Transmission Projects	Operational Changes
2023	n/a	85.49	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2024	139	-	-	-	n/a	n/a	30.00	133.00	-	n/a	n/a	-	n/a
2025	139	113.21	475.00	1,900.00	n/a	n/a	60.00	162.00	-	n/a	n/a	-	n/a
2026	707	114.47	475.00	1,900.00	n/a	n/a	90.00	183.00	12.55	n/a	n/a	-	n/a
2027	1,014	115.74	475.00	1,900.00	n/a	n/a	120.00	199.00	16.01	n/a	n/a	400.00	n/a
2028	1,231	116.89	475.00	1,900.00	n/a	n/a	150.00	211.00	21.58	n/a	n/a	400.00	n/a
2029	1,382	118.28	475.00	1,900.00	n/a	n/a	183.00	218.00	26.79	n/a	n/a	400.00	n/a
2030	1,414	119.55	900.00	3,600.00	n/a	n/a	216.00	228.00	30.80	n/a	n/a	400.00	n/a
2031	1,523	119.04	975.00	3,900.00	n/a	n/a	251.00	242.00	30.80	n/a	n/a	400.00	n/a
2032	1,653	118.41	975.00	3,900.00	n/a	n/a	285.00	252.00	30.80	n/a	n/a	400.00	n/a
2033	1,782	118.02	975.00	3,900.00	n/a	n/a	317.00	261.00	30.80	n/a	n/a	400.00	n/a
2034	1,917	117.52	975.00	3,900.00	n/a	n/a	348.00	270.00	30.80	n/a	n/a	400.00	n/a
2035	2,075	117.01	975.00	3,900.00	n/a	n/a	377.00	272.00	30.80	n/a	n/a	400.00	n/a
2036	2,264	116.40	975.00	3,900.00	n/a	n/a	404.00	287.00	30.80	n/a	n/a	400.00	n/a
2037	2,454	67.75	975.00	3,900.00	n/a	n/a	429.00	296.00	30.80	n/a	n/a	400.00	n/a
2038	2,632	41.47	1,075.00	4,300.00	n/a	n/a	452.00	303.00	30.80	n/a	n/a	400.00	n/a
2039	2,811	16.93	1,175.00	4,700.00	n/a	n/a	471.00	310.00	30.80	n/a	n/a	400.00	n/a
2040	2,960	16.93	1,275.00	5,100.00	n/a	n/a	487.00	306.00	30.80	n/a	n/a	400.00	n/a
2041	3,145	16.93	1,275.00	5,100.00	n/a	n/a	503.00	314.00	30.80	n/a	n/a	400.00	n/a
2042	3,232	16.93	1,275.00	5,100.00	n/a	n/a	514.00	330.00	30.80	n/a	n/a	400.00	n/a
2043	3,321	16.93	1,275.00	5,100.00	n/a	n/a	523.00	336.00	30.80	n/a	n/a	400.00	n/a

3	Portfolio3	Back-loaded decline							CBREs (MWa)	CBREs (MW or MWa)			
Year	Clean energy resources (MWa) System resources	Clean energy resources (MWa) Voluntary programs	Energy Storage (MW) System resources	Energy Storage (MWh) System resources	Energy Storage (MW) Voluntary programs	Energy Storage (MWh) Voluntary programs	Energy Efficiency (MWa)	Demand Response (MW)	System resources	Voluntary programs	Retirements (list unit)	Transmission Projects	Operational Changes
2023	n/a	85.49	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2024	138.60	112.47	-	-	n/a	n/a	30.00	133.00	-	n/a	n/a	-	n/a
2025	138.61	113.21	475.00	1,900.00	n/a	n/a	60.00	162.00	-	n/a	n/a	-	n/a
2026	589.20	114.47	707.00	2,828.00	n/a	n/a	90.00	183.00	12.54	n/a	n/a	-	n/a
2027	679.92	115.74	707.00	2,828.00	n/a	n/a	120.00	199.00	16.01	n/a	n/a	205.00	n/a
2028	789.32	116.89	707.00	2,828.00	n/a	n/a	150.00	211.00	21.56	n/a	n/a	400.00	n/a
2029	970.11	118.28	707.00	2,828.00	n/a	n/a	183.00	218.00	26.77	n/a	n/a	400.00	n/a
2030	1,412.65	119.55	811.00	3,244.00	n/a	n/a	216.00	228.00	30.80	n/a	n/a	400.00	n/a
2031	1,522.47	119.04	911.00	3,644.00	n/a	n/a	251.00	242.00	30.80	n/a	n/a	400.00	n/a
2032	1,651.88	118.41	911.00	3,644.00	n/a	n/a	285.00	252.00	30.80	n/a	n/a	400.00	n/a
2033	1,781.42	118.02	911.00	3,644.00	n/a	n/a	317.00	261.00	30.80	n/a	n/a	400.00	n/a
2034	1,916.55	117.52	911.00	3,644.00	n/a	n/a	348.00	270.00	30.80	n/a	n/a	400.00	n/a
2035	2,075.04	117.01	911.00	3,644.00	n/a	n/a	377.00	272.00	30.80	n/a	n/a	400.00	n/a
2036	2,264.42	116.40	911.00	3,644.00	n/a	n/a	404.00	287.00	30.80	n/a	n/a	400.00	n/a
2037	2,454.09	67.75	975.00	3,900.00	n/a	n/a	429.00	296.00	30.80	n/a	n/a	400.00	n/a
2038	2,631.79	41.47	1,075.00	4,300.00	n/a	n/a	452.00	303.00	30.80	n/a	n/a	400.00	n/a
2039	2,811.36	16.93	1,175.00	4,700.00	n/a	n/a	471.00	310.00	30.80	n/a	n/a	400.00	n/a
2040	2,960.39	16.93	1,275.00	5,100.00	n/a	n/a	487.00	306.00	30.80	n/a	n/a	400.00	n/a
2041	3,145.02	16.93	1,275.00	5,100.00	n/a	n/a	503.00	314.00	30.80	n/a	n/a	400.00	n/a
2042	3,232.38	16.93	1,275.00	5,100.00	n/a	n/a	514.00	330.00	30.80	n/a	n/a	400.00	n/a
2043	3,320.52	16.93	1,275.00	5,100.00	n/a	n/a	523.00	336.00	30.80	n/a	n/a	400.00	n/a

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual goals for actions over the study period

UM 2225 Order Summary/Rubric references: C.2(a)-(i), C.3

Note: This column reflects both the EE that was previously deemed cost effective by Energy Trust and any additional EE selected in this portfolio

Note: this column reflects both the DR that was previously deemed cost effective by PGE and any additional DR selected in this portfolio

4 Portfolio4 — 100% emissions reduction by 2035

Year	Clean energy resources (MWa) System resources	Clean energy resources (MWa) Voluntary programs	Energy Storage (MW) System resources	Energy Storage (MWh) System resources	Energy Storage (MW) Voluntary programs	Energy Storage (MWh) Voluntary programs	Energy Efficiency (MWa)	Demand Response (MW)	CBREs (MWa) System resources	CBREs (MW or MWa) Voluntary programs	Retirements (list unit)	Transmission Projects	Operational Changes
2023	n/a	85.49	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2024	138.60	112.47	-	-	n/a	n/a	30.00	133.00	-	n/a	n/a	-	n/a
2025	138.61	113.21	475.00	1,900.00	n/a	n/a	60.00	162.00	-	n/a	n/a	-	n/a
2026	633.42	114.47	475.00	1,900.00	n/a	n/a	90.00	183.00	12.55	n/a	n/a	-	n/a
2027	734.25	115.74	475.00	1,900.00	n/a	n/a	120.00	199.00	16.01	n/a	n/a	228.00	n/a
2028	972.18	116.89	475.00	1,900.00	n/a	n/a	150.00	211.00	21.57	n/a	n/a	400.00	n/a
2029	1,237.96	118.28	475.00	1,900.00	n/a	n/a	183.00	218.00	26.76	n/a	n/a	400.00	n/a
2030	1,412.73	119.55	816.00	3,264.00	n/a	n/a	216.00	228.00	30.79	n/a	n/a	400.00	n/a
2031	1,567.97	119.04	875.00	3,500.00	n/a	n/a	251.00	242.00	30.80	n/a	n/a	400.00	n/a
2032	1,742.33	118.41	875.00	3,500.00	n/a	n/a	285.00	252.00	30.80	n/a	n/a	400.00	n/a
2033	1,918.93	118.02	875.00	3,500.00	n/a	n/a	317.00	261.00	30.80	n/a	n/a	400.00	n/a
2034	2,100.05	117.52	875.00	3,500.00	n/a	n/a	348.00	270.00	30.80	n/a	n/a	400.00	n/a
2035	2,294.63	117.01	875.00	3,500.00	n/a	n/a	377.00	272.00	30.80	n/a	n/a	400.00	n/a
2036	2,427.68	116.40	875.00	3,500.00	n/a	n/a	404.00	287.00	30.80	n/a	n/a	400.00	n/a
2037	2,592.08	67.75	975.00	3,900.00	n/a	n/a	429.00	296.00	30.80	n/a	n/a	400.00	n/a
2038	2,724.79	41.47	1,075.00	4,300.00	n/a	n/a	452.00	303.00	30.80	n/a	n/a	400.00	n/a
2039	2,858.36	16.93	1,175.00	4,700.00	n/a	n/a	471.00	310.00	30.80	n/a	n/a	400.00	n/a
2040	2,960.40	16.93	1,275.00	5,100.00	n/a	n/a	487.00	306.00	30.80	n/a	n/a	400.00	n/a
2041	3,145.01	16.93	1,275.00	5,100.00	n/a	n/a	503.00	314.00	30.80	n/a	n/a	400.00	n/a
2042	3,232.39	16.93	1,275.00	5,100.00	n/a	n/a	514.00	330.00	30.80	n/a	n/a	400.00	n/a
2043	3,320.52	16.93	1,275.00	5,100.00	n/a	n/a	523.00	336.00	30.80	n/a	n/a	400.00	n/a

5 Portfolio5 — 2-yr forward shift in targets

Year	Clean energy resources (MWa) System resources	Clean energy resources (MWa) Voluntary programs	Energy Storage (MW) System resources	Energy Storage (MWh) System resources	Energy Storage (MW) Voluntary programs	Energy Storage (MWh) Voluntary programs	Energy Efficiency (MWa)	Demand Response (MW)	CBREs (MWa) System resources	CBREs (MW or MWa) Voluntary programs	Retirements (list unit)	Transmission Projects	Operational Changes
2023	n/a	85.49	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2024	138.60	112.47	-	-	n/a	n/a	30.00	133.00	-	n/a	n/a	-	n/a
2025	138.61	113.21	475.00	1,900.00	n/a	n/a	60.00	162.00	-	n/a	n/a	-	n/a
2026	633.43	114.47	475.00	1,900.00	n/a	n/a	90.00	183.00	12.55	n/a	n/a	-	n/a
2027	920.74	115.74	475.00	1,900.00	n/a	n/a	120.00	199.00	16.01	n/a	n/a	400.00	n/a
2028	1,314.16	116.89	475.00	1,900.00	n/a	n/a	150.00	211.00	21.58	n/a	n/a	400.00	n/a
2029	1,450.95	118.28	475.00	1,900.00	n/a	n/a	183.00	218.00	26.79	n/a	n/a	400.00	n/a
2030	1,504.25	119.55	782.00	3,128.00	n/a	n/a	216.00	228.00	30.80	n/a	n/a	400.00	n/a
2031	1,614.09	119.04	882.00	3,528.00	n/a	n/a	251.00	242.00	30.80	n/a	n/a	400.00	n/a
2032	1,742.44	118.41	882.00	3,528.00	n/a	n/a	285.00	252.00	30.80	n/a	n/a	400.00	n/a
2033	1,873.01	118.02	882.00	3,528.00	n/a	n/a	317.00	261.00	30.80	n/a	n/a	400.00	n/a
2034	2,008.15	117.52	882.00	3,528.00	n/a	n/a	348.00	270.00	30.80	n/a	n/a	400.00	n/a
2035	2,167.00	117.01	882.00	3,528.00	n/a	n/a	377.00	272.00	30.80	n/a	n/a	400.00	n/a
2036	2,356.36	116.40	882.00	3,528.00	n/a	n/a	404.00	287.00	30.80	n/a	n/a	400.00	n/a
2037	2,546.09	67.75	975.00	3,900.00	n/a	n/a	429.00	296.00	30.80	n/a	n/a	400.00	n/a
2038	2,724.79	41.47	1,075.00	4,300.00	n/a	n/a	452.00	303.00	30.80	n/a	n/a	400.00	n/a
2039	2,858.34	16.93	1,175.00	4,700.00	n/a	n/a	471.00	310.00	30.80	n/a	n/a	400.00	n/a
2040	2,960.39	16.93	1,275.00	5,100.00	n/a	n/a	487.00	306.00	30.80	n/a	n/a	400.00	n/a
2041	3,145.01	16.93	1,275.00	5,100.00	n/a	n/a	503.00	314.00	30.80	n/a	n/a	400.00	n/a
2042	3,232.38	16.93	1,275.00	5,100.00	n/a	n/a	514.00	330.00	30.80	n/a	n/a	400.00	n/a
2043	3,320.52	16.93	1,275.00	5,100.00	n/a	n/a	523.00	336.00	30.80	n/a	n/a	400.00	n/a

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual goals for actions over the study period

UM 2225 Order Summary/Rubric references: C.2(a)-(i), C.3

	Note: This column reflects both the EE that was previously deemed cost effective by Energy Trust and any additional EE selected in this portfolio	Note: this column reflects both the DR that was previously deemed cost effective by PGE and any additional DR selected in this portfolio

6 Portfolio6 — Optimize NCE

Year	Clean energy resources (MWa) System resources	Clean energy resources (MWa) Voluntary programs	Energy Storage (MW) System resources	Energy Storage (MWh) System resources	Energy Storage (MW) Voluntary programs	Energy Storage (MWh) Voluntary programs	Energy Efficiency (MWa)	Demand Response (MW)	CBREs (MWa) System resources	CBREs (MW or MWa) Voluntary programs	Retirements (list unit)	Transmission Projects	Operational Changes
2023	n/a	85.49	n/a	n/a	n/a	n/a	n/a	n/a		n/a	n/a	n/a	n/a
2024	138.60	112.47	-	-	n/a	n/a	30.00	133.00	-	n/a	n/a	-	n/a
2025	138.61	113.21	475.00	1,900.00	n/a	n/a	60.03	162.00	-	n/a	n/a	-	n/a
2026	629.87	114.47	475.00	1,900.00	n/a	n/a	102.06	183.00	12.54	n/a	n/a	-	n/a
2027	712.82	115.74	475.00	1,900.00	n/a	n/a	142.09	199.00	16.01	n/a	n/a	187.00	n/a
2028	940.18	116.89	475.00	1,900.00	n/a	n/a	182.12	211.00	21.56	n/a	n/a	400.00	n/a
2029	1,194.96	118.28	475.00	1,900.00	n/a	n/a	226.15	218.00	26.76	n/a	n/a	400.00	n/a
2030	1,357.09	119.55	629.00	2,516.00	n/a	n/a	269.18	228.00	30.79	n/a	n/a	400.00	n/a
2031	1,467.02	119.04	729.00	2,916.00	n/a	n/a	304.23	242.00	30.80	n/a	n/a	400.00	n/a
2032	1,597.68	118.41	829.00	3,316.00	n/a	n/a	338.28	252.00	30.80	n/a	n/a	400.00	n/a
2033	1,727.93	118.02	875.00	3,500.00	n/a	n/a	370.33	261.00	30.80	n/a	n/a	400.00	n/a
2034	1,863.05	117.52	875.00	3,500.00	n/a	n/a	401.38	270.00	30.80	n/a	n/a	400.00	n/a
2035	2,022.03	117.01	875.00	3,500.00	n/a	n/a	430.43	272.00	30.80	n/a	n/a	400.00	n/a
2036	2,211.40	116.40	875.00	3,500.00	n/a	n/a	457.48	287.00	30.80	n/a	n/a	400.00	n/a
2037	2,401.08	67.75	975.00	3,900.00	n/a	n/a	482.53	296.00	30.80	n/a	n/a	400.00	n/a
2038	2,578.79	41.47	1,075.00	4,300.00	n/a	n/a	505.58	303.00	30.80	n/a	n/a	400.00	n/a
2039	2,758.36	16.93	1,175.00	4,700.00	n/a	n/a	524.63	310.00	30.80	n/a	n/a	400.00	n/a
2040	2,907.40	16.93	1,275.00	5,100.00	n/a	n/a	540.68	306.00	30.80	n/a	n/a	400.00	n/a
2041	3,092.01	16.93	1,275.00	5,100.00	n/a	n/a	556.73	314.00	30.80	n/a	n/a	400.00	n/a
2042	3,179.39	16.93	1,275.00	5,100.00	n/a	n/a	567.78	330.00	30.80	n/a	n/a	400.00	n/a
2043	3,267.52	16.93	1,275.00	5,100.00	n/a	n/a	576.83	336.00	30.80	n/a	n/a	400.00	n/a

7 Portfolio7 — Zero NCE

Year	Clean energy resources (MWa) System resources	Clean energy resources (MWa) Voluntary programs	Energy Storage (MW) System resources	Energy Storage (MWh) System resources	Energy Storage (MW) Voluntary programs	Energy Storage (MWh) Voluntary programs	Energy Efficiency (MWa)	Demand Response (MW)	CBREs (MWa) System resources	CBREs (MW or MWa) Voluntary programs	Retirements (list unit)	Transmission Projects	Operational Changes
2023	n/a	85.49	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2024	138.60	112.47	-	-	n/a	n/a	30.00	133.00	-	n/a	n/a	-	n/a
2025	138.61	113.21	475.00	1,900.00	n/a	n/a	60.00	162.00	-	n/a	n/a	-	n/a
2026	633.42	114.47	475.00	1,900.00	n/a	n/a	90.00	183.00	12.54	n/a	n/a	-	n/a
2027	734.27	115.74	475.00	1,900.00	n/a	n/a	120.00	199.00	16.01	n/a	n/a	228.00	n/a
2028	972.18	116.89	475.00	1,900.00	n/a	n/a	150.00	211.00	21.56	n/a	n/a	400.00	n/a
2029	1,237.96	118.28	475.00	1,900.00	n/a	n/a	183.00	218.00	26.77	n/a	n/a	400.00	n/a
2030	1,412.73	119.55	816.00	3,264.00	n/a	n/a	216.00	228.00	30.80	n/a	n/a	400.00	n/a
2031	1,522.55	119.04	916.00	3,664.00	n/a	n/a	251.00	242.00	30.80	n/a	n/a	400.00	n/a
2032	1,651.95	118.41	916.00	3,664.00	n/a	n/a	285.00	252.00	30.80	n/a	n/a	400.00	n/a
2033	1,781.48	118.02	916.00	3,664.00	n/a	n/a	317.00	261.00	30.80	n/a	n/a	400.00	n/a
2034	1,916.63	117.52	916.00	3,664.00	n/a	n/a	348.00	270.00	30.80	n/a	n/a	400.00	n/a
2035	2,075.03	117.01	916.00	3,664.00	n/a	n/a	377.00	272.00	30.80	n/a	n/a	400.00	n/a
2036	2,264.40	116.40	916.00	3,664.00	n/a	n/a	404.00	287.00	30.80	n/a	n/a	400.00	n/a
2037	2,454.08	67.75	975.00	3,900.00	n/a	n/a	429.00	296.00	30.80	n/a	n/a	400.00	n/a
2038	2,631.79	41.47	1,075.00	4,300.00	n/a	n/a	452.00	303.00	30.80	n/a	n/a	400.00	n/a
2039	2,811.35	16.93	1,175.00	4,700.00	n/a	n/a	471.00	310.00	30.80	n/a	n/a	400.00	n/a
2040	2,960.40	16.93	1,275.00	5,100.00	n/a	n/a	487.00	306.00	30.80	n/a	n/a	400.00	n/a
2041	3,145.01	16.93	1,275.00	5,100.00	n/a	n/a	503.00	314.00	30.80	n/a	n/a	400.00	n/a
2042	3,232.38	16.93	1,275.00	5,100.00	n/a	n/a	514.00	330.00	30.80	n/a	n/a	400.00	n/a
2043	3,320.52	16.93	1,275.00	5,100.00	n/a	n/a	523.00	336.00	30.80	n/a	n/a	400.00	n/a

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual goals for actions over the study period

UM 2225 Order Summary/Rubric references: C.2(a)-(i), C.3

								Note: This column reflects both the EE that was previously deemed cost effective by Energy Trust and any additional EE selected in this portfolio	Note: this column reflects both the DR that was previously deemed cost effective by PGE and any additional DR selected in this portfolio					
8	Portfolio8	60 MWa EE								CBREs (MWa)	CBREs (MW or MWa)			
Year	Clean energy resources (MWa) System resources	Clean energy resources (MWa) Voluntary programs	Energy Storage (MW) System resources	Energy Storage (MWh) System resources	Energy Storage (MW) Voluntary programs	Energy Storage (MWh) Voluntary programs	Energy Efficiency (MWa)	Demand Response (MW)	System resources	Voluntary programs	Retirements (list unit)	Transmission Projects	Operational Changes
2023	n/a	85.49	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2024	138.60	112.47	-	-	n/a	n/a	30.00	133.00	-	n/a	n/a	-	n/a
2025	138.61	113.21	475.00	1,900.00	n/a	n/a	60.00	162.00	-	n/a	n/a	-	n/a
2026	629.52	114.47	475.00	1,900.00	n/a	n/a	102.06	183.00	12.54	n/a	n/a	-	n/a
2027	709.92	115.74	475.00	1,900.00	n/a	n/a	144.09	199.00	16.01	n/a	n/a	181.00	n/a
2028	936.18	116.89	475.00	1,900.00	n/a	n/a	186.12	211.00	21.56	n/a	n/a	400.00	n/a
2029	1,189.96	118.28	475.00	1,900.00	n/a	n/a	231.15	218.00	26.76	n/a	n/a	400.00	n/a
2030	1,349.88	119.55	613.00	2,452.00	n/a	n/a	276.16	228.00	30.79	n/a	n/a	400.00	n/a
2031	1,459.82	119.04	713.00	2,852.00	n/a	n/a	311.21	242.00	30.80	n/a	n/a	400.00	n/a
2032	1,590.47	118.41	813.00	3,252.00	n/a	n/a	345.26	252.00	30.80	n/a	n/a	400.00	n/a
2033	1,720.95	118.02	875.00	3,500.00	n/a	n/a	377.31	261.00	30.80	n/a	n/a	400.00	n/a
2034	1,856.07	117.52	875.00	3,500.00	n/a	n/a	408.36	270.00	30.80	n/a	n/a	400.00	n/a
2035	2,015.05	117.01	875.00	3,500.00	n/a	n/a	437.41	272.00	30.80	n/a	n/a	400.00	n/a
2036	2,204.42	116.40	875.00	3,500.00	n/a	n/a	464.46	287.00	30.80	n/a	n/a	400.00	n/a
2037	2,394.10	67.75	975.00	3,900.00	n/a	n/a	489.51	296.00	30.80	n/a	n/a	400.00	n/a
2038	2,571.81	41.47	1,075.00	4,300.00	n/a	n/a	512.56	303.00	30.80	n/a	n/a	400.00	n/a
2039	2,751.38	16.93	1,175.00	4,700.00	n/a	n/a	531.61	310.00	30.80	n/a	n/a	400.00	n/a
2040	2,900.42	16.93	1,275.00	5,100.00	n/a	n/a	547.66	306.00	30.80	n/a	n/a	400.00	n/a
2041	3,085.03	16.93	1,275.00	5,100.00	n/a	n/a	563.71	314.00	30.80	n/a	n/a	400.00	n/a
2042	3,172.41	16.93	1,275.00	5,100.00	n/a	n/a	574.76	330.00	30.80	n/a	n/a	400.00	n/a
2043	3,260.54	16.93	1,275.00	5,100.00	n/a	n/a	583.81	336.00	30.80	n/a	n/a	400.00	n/a

9	Portfolio9	Default CBREs							CBREs (MWa)	CBREs (MW or MWa)			
Year	Clean energy resources (MWa) System resources	Clean energy resources (MWa) Voluntary programs	Energy Storage (MW) System resources	Energy Storage (MWh) System resources	Energy Storage (MW) Voluntary programs	Energy Storage (MWh) Voluntary programs	Energy Efficiency (MWa)	Demand Response (MW)	System resources	Voluntary programs	Retirements (list unit)	Transmission Projects	Operational Changes
2023	n/a	85.49	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2024	138.60	112.47	-	-	n/a	n/a	30.00	133.00	-	n/a	n/a	-	n/a
2025	138.61	113.21	475.00	1,900.00	n/a	n/a	60.00	162.00	-	n/a	n/a	-	n/a
2026	633.42	114.47	475.00	1,900.00	n/a	n/a	90.00	183.00	12.54	n/a	n/a	-	n/a
2027	734.27	115.74	475.00	1,900.00	n/a	n/a	120.00	199.00	16.01	n/a	n/a	228.00	n/a
2028	972.18	116.89	475.00	1,900.00	n/a	n/a	150.00	211.00	21.56	n/a	n/a	400.00	n/a
2029	1,237.96	118.28	475.00	1,900.00	n/a	n/a	183.00	218.00	26.77	n/a	n/a	400.00	n/a
2030	1,412.73	119.55	816.00	3,264.00	n/a	n/a	216.00	228.00	30.80	n/a	n/a	400.00	n/a
2031	1,522.55	119.04	916.00	3,664.00	n/a	n/a	251.00	242.00	30.80	n/a	n/a	400.00	n/a
2032	1,651.95	118.41	916.00	3,664.00	n/a	n/a	285.00	252.00	30.80	n/a	n/a	400.00	n/a
2033	1,781.48	118.02	916.00	3,664.00	n/a	n/a	317.00	261.00	30.80	n/a	n/a	400.00	n/a
2034	1,916.63	117.52	916.00	3,664.00	n/a	n/a	348.00	270.00	30.80	n/a	n/a	400.00	n/a
2035	2,075.03	117.01	916.00	3,664.00	n/a	n/a	377.00	272.00	30.80	n/a	n/a	400.00	n/a
2036	2,264.40	116.40	916.00	3,664.00	n/a	n/a	404.00	287.00	30.80	n/a	n/a	400.00	n/a
2037	2,454.08	67.75	975.00	3,900.00	n/a	n/a	429.00	296.00	30.80	n/a	n/a	400.00	n/a
2038	2,631.79	41.47	1,075.00	4,300.00	n/a	n/a	452.00	303.00	30.80	n/a	n/a	400.00	n/a
2039	2,811.35	16.93	1,175.00	4,700.00	n/a	n/a	471.00	310.00	30.80	n/a	n/a	400.00	n/a
2040	2,960.40	16.93	1,275.00	5,100.00	n/a	n/a	487.00	306.00	30.80	n/a	n/a	400.00	n/a
2041	3,145.01	16.93	1,275.00	5,100.00	n/a	n/a	503.00	314.00	30.80	n/a	n/a	400.00	n/a
2042	3,232.38	16.93	1,275.00	5,100.00	n/a	n/a	514.00	330.00	30.80	n/a	n/a	400.00	n/a
2043	3,320.52	16.93	1,275.00	5,100.00	n/a	n/a	523.00	336.00	30.80	n/a	n/a	400.00	n/a

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual goals for actions over the study period

UM 2225 Order Summary/Rubric references: C.2(a)-(i), C.3

	Note: This column reflects both the EE that was previously deemed cost effective by Energy Trust and any additional EE selected in this portfolio	Note: this column reflects both the DR that was previously deemed cost effective by PGE and any additional DR selected in this portfolio

10 Portfolio10 CBRE - 75%

Year	Clean energy resources (MWa) System resources	Clean energy resources (MWa) Voluntary programs	Energy Storage (MW) System resources	Energy Storage (MWh) System resources	Energy Storage (MW) Voluntary programs	Energy Storage (MWh) Voluntary programs	Energy Efficiency (MWa)	Demand Response (MW)	CBREs (MWa) System resources	CBREs (MW or MWa) Voluntary programs	Retirements (list unit)	Transmission Projects	Operational Changes
2023	n/a	85.49	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2024	138.60	112.47	-	-	n/a	n/a	30.00	133.00	-	n/a	n/a	-	n/a
2025	138.61	113.21	475.00	1,900.00	n/a	n/a	60.00	162.00	0.01	n/a	n/a	-	n/a
2026	635.65	114.47	475.00	1,900.00	n/a	n/a	90.00	183.00	9.48	n/a	n/a	-	n/a
2027	737.55	115.74	475.00	1,900.00	n/a	n/a	120.00	199.00	12.09	n/a	n/a	231.00	n/a
2028	977.48	116.89	475.00	1,900.00	n/a	n/a	150.00	211.00	16.29	n/a	n/a	400.00	n/a
2029	1,244.54	118.28	475.00	1,900.00	n/a	n/a	183.00	218.00	20.21	n/a	n/a	400.00	n/a
2030	1,420.92	119.55	861.00	3,444.00	n/a	n/a	216.00	228.00	23.24	n/a	n/a	400.00	n/a
2031	1,530.71	119.04	961.00	3,844.00	n/a	n/a	251.00	242.00	23.26	n/a	n/a	400.00	n/a
2032	1,660.15	118.41	961.00	3,844.00	n/a	n/a	285.00	252.00	23.27	n/a	n/a	400.00	n/a
2033	1,789.63	118.02	961.00	3,844.00	n/a	n/a	317.00	261.00	23.28	n/a	n/a	400.00	n/a
2034	1,924.78	117.52	961.00	3,844.00	n/a	n/a	348.00	270.00	23.29	n/a	n/a	400.00	n/a
2035	2,082.52	117.01	961.00	3,844.00	n/a	n/a	377.00	272.00	23.30	n/a	n/a	400.00	n/a
2036	2,271.88	116.40	961.00	3,844.00	n/a	n/a	404.00	287.00	23.32	n/a	n/a	400.00	n/a
2037	2,461.57	67.75	975.00	3,900.00	n/a	n/a	429.00	296.00	23.32	n/a	n/a	400.00	n/a
2038	2,639.27	41.47	1,075.00	4,300.00	n/a	n/a	452.00	303.00	23.33	n/a	n/a	400.00	n/a
2039	2,818.82	16.93	1,175.00	4,700.00	n/a	n/a	471.00	310.00	23.34	n/a	n/a	400.00	n/a
2040	2,967.85	16.93	1,275.00	5,100.00	n/a	n/a	487.00	306.00	23.35	n/a	n/a	400.00	n/a
2041	3,152.46	16.93	1,275.00	5,100.00	n/a	n/a	503.00	314.00	23.36	n/a	n/a	400.00	n/a
2042	3,239.82	16.93	1,275.00	5,100.00	n/a	n/a	514.00	330.00	23.38	n/a	n/a	400.00	n/a
2043	3,327.94	16.93	1,275.00	5,100.00	n/a	n/a	523.00	336.00	23.38	n/a	n/a	400.00	n/a

11 Portfolio11 CBRE - zero

Year	Clean energy resources (MWa) System resources	Clean energy resources (MWa) Voluntary programs	Energy Storage (MW) System resources	Energy Storage (MWh) System resources	Energy Storage (MW) Voluntary programs	Energy Storage (MWh) Voluntary programs	Energy Efficiency (MWa)	Demand Response (MW)	CBREs (MWa) System resources	CBREs (MW or MWa) Voluntary programs	Retirements (list unit)	Transmission Projects	Operational Changes
2023	n/a	85.49	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2024	138.60	112.47	-	-	n/a	n/a	30.00	133.00	-	n/a	n/a	-	n/a
2025	138.61	113.21	475.00	1,900.00	n/a	n/a	60.00	162.00	0.01	n/a	n/a	-	n/a
2026	642.49	114.47	475.00	1,900.00	n/a	n/a	90.00	183.00	0.01	n/a	n/a	-	n/a
2027	747.82	115.74	475.00	1,900.00	n/a	n/a	120.00	199.00	0.04	n/a	n/a	239.00	n/a
2028	993.72	116.89	475.00	1,900.00	n/a	n/a	150.00	211.00	0.05	n/a	n/a	400.00	n/a
2029	1,264.69	118.28	475.00	1,900.00	n/a	n/a	183.00	218.00	0.05	n/a	n/a	400.00	n/a
2030	1,445.72	119.55	975.00	3,900.00	n/a	n/a	216.00	228.00	0.06	n/a	n/a	400.00	n/a
2031	1,554.08	119.04	975.00	3,900.00	n/a	n/a	251.00	242.00	0.07	n/a	n/a	400.00	n/a
2032	1,683.53	118.41	975.00	3,900.00	n/a	n/a	285.00	252.00	0.07	n/a	n/a	400.00	n/a
2033	1,813.00	118.02	975.00	3,900.00	n/a	n/a	317.00	261.00	0.10	n/a	n/a	400.00	n/a
2034	1,948.16	117.52	975.00	3,900.00	n/a	n/a	348.00	270.00	0.11	n/a	n/a	400.00	n/a
2035	2,105.70	117.01	975.00	3,900.00	n/a	n/a	377.00	272.00	0.11	n/a	n/a	400.00	n/a
2036	2,295.07	116.40	975.00	3,900.00	n/a	n/a	404.00	287.00	0.12	n/a	n/a	400.00	n/a
2037	2,484.75	67.75	975.00	3,900.00	n/a	n/a	429.00	296.00	0.13	n/a	n/a	400.00	n/a
2038	2,662.45	41.47	1,075.00	4,300.00	n/a	n/a	452.00	303.00	0.16	n/a	n/a	400.00	n/a
2039	2,842.00	16.93	1,175.00	4,700.00	n/a	n/a	471.00	310.00	0.16	n/a	n/a	400.00	n/a
2040	2,991.03	16.93	1,275.00	5,100.00	n/a	n/a	487.00	306.00	0.17	n/a	n/a	400.00	n/a
2041	3,175.64	16.93	1,275.00	5,100.00	n/a	n/a	503.00	314.00	0.18	n/a	n/a	400.00	n/a
2042	3,263.00	16.93	1,275.00	5,100.00	n/a	n/a	514.00	330.00	0.18	n/a	n/a	400.00	n/a
2043	3,351.13	16.93	1,275.00	5,100.00	n/a	n/a	523.00	336.00	0.19	n/a	n/a	400.00	n/a

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual goals for actions over the study period

UM 2225 Order Summary/Rubric references: C.2(a)-(i), C.3

Note: This column reflects both the EE that was previously deemed cost effective by Energy Trust and any additional EE selected in this portfolio

Note: this column reflects both the DR that was previously deemed cost effective by PGE and any additional DR selected in this portfolio

12	Portfolio12	CBRE - microgrid											
	Clean energy resources (MWa)	Clean energy resources (MWa)	Energy Storage (MW)	Energy Storage (MWh)	Energy Storage (MW)	Energy Storage (MWh)			CBREs (MWa)	CBREs (MW or MWa)			
Year	System resources	Voluntary programs	System resources	System resources	Voluntary programs	Voluntary programs	Energy Efficiency (MWa)	Demand Response (MW)	System resources	Voluntary programs	Retirements (list unit)	Transmission Projects	Operational Changes
2023	n/a	85.49	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2024	138.60	112.47	-	-	n/a	n/a	30.00	133.00	-	n/a	n/a	-	n/a
2025	138.61	113.21	475.00	1,900.00	n/a	n/a	60.00	162.00	0.01	n/a	n/a	-	n/a
2026	634.94	114.47	475.00	1,900.00	n/a	n/a	90.00	183.00	7.86	n/a	n/a	-	n/a
2027	735.52	115.74	475.00	1,900.00	n/a	n/a	120.00	199.00	10.26	n/a	n/a	228.00	n/a
2028	980.75	116.89	475.00	1,900.00	n/a	n/a	150.00	211.00	13.00	n/a	n/a	400.00	n/a
2029	1,249.17	118.28	475.00	1,900.00	n/a	n/a	183.00	218.00	15.56	n/a	n/a	400.00	n/a
2030	1,425.55	119.55	840.00	3,360.00	n/a	n/a	216.00	228.00	18.31	n/a	n/a	400.00	n/a
2031	1,535.35	119.04	940.00	3,760.00	n/a	n/a	251.00	242.00	18.32	n/a	n/a	400.00	n/a
2032	1,664.76	118.41	940.00	3,760.00	n/a	n/a	285.00	252.00	18.32	n/a	n/a	400.00	n/a
2033	1,794.27	118.02	940.00	3,760.00	n/a	n/a	317.00	261.00	18.34	n/a	n/a	400.00	n/a
2034	1,929.41	117.52	940.00	3,760.00	n/a	n/a	348.00	270.00	18.35	n/a	n/a	400.00	n/a
2035	2,087.46	117.01	940.00	3,760.00	n/a	n/a	377.00	272.00	18.35	n/a	n/a	400.00	n/a
2036	2,276.82	116.40	940.00	3,760.00	n/a	n/a	404.00	287.00	18.36	n/a	n/a	400.00	n/a
2037	2,466.51	67.75	975.00	3,900.00	n/a	n/a	429.00	296.00	18.37	n/a	n/a	400.00	n/a
2038	2,644.21	41.47	1,075.00	4,300.00	n/a	n/a	452.00	303.00	18.39	n/a	n/a	400.00	n/a
2039	2,823.77	16.93	1,175.00	4,700.00	n/a	n/a	471.00	310.00	18.39	n/a	n/a	400.00	n/a
2040	2,972.80	16.93	1,275.00	5,100.00	n/a	n/a	487.00	306.00	18.40	n/a	n/a	400.00	n/a
2041	3,157.41	16.93	1,275.00	5,100.00	n/a	n/a	503.00	314.00	18.41	n/a	n/a	400.00	n/a
2042	3,244.77	16.93	1,275.00	5,100.00	n/a	n/a	514.00	330.00	18.41	n/a	n/a	400.00	n/a
2043	3,332.90	16.93	1,275.00	5,100.00	n/a	n/a	523.00	336.00	18.42	n/a	n/a	400.00	n/a

13	Portfolio13	CBRE - optimize											
	Clean energy resources (MWa)	Clean energy resources (MWa)	Energy Storage (MW)	Energy Storage (MWh)	Energy Storage (MW)	Energy Storage (MWh)			CBREs (MWa)	CBREs (MW or MWa)			
Year	System resources	Voluntary programs	System resources	System resources	Voluntary programs	Voluntary programs	Energy Efficiency (MWa)	Demand Response (MW)	System resources	Voluntary programs	Retirements (list unit)	Transmission Projects	Operational Changes
2023	n/a	85.49	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2024	138.60	112.47	-	-	n/a	n/a	30.00	133.00	-	n/a	n/a	-	n/a
2025	138.61	113.21	475.00	1,900.00	n/a	n/a	60.00	162.00	-	n/a	n/a	-	n/a
2026	633.42	114.47	475.00	1,900.00	n/a	n/a	90.00	183.00	12.51	n/a	n/a	-	n/a
2027	734.27	115.74	475.00	1,900.00	n/a	n/a	120.00	199.00	15.98	n/a	n/a	228.00	n/a
2028	972.18	116.89	475.00	1,900.00	n/a	n/a	150.00	211.00	21.55	n/a	n/a	400.00	n/a
2029	1,237.95	118.28	475.00	1,900.00	n/a	n/a	183.00	218.00	26.75	n/a	n/a	400.00	n/a
2030	1,412.73	119.55	816.00	3,264.00	n/a	n/a	216.00	228.00	30.78	n/a	n/a	400.00	n/a
2031	1,522.55	119.04	916.00	3,664.00	n/a	n/a	251.00	242.00	30.80	n/a	n/a	400.00	n/a
2032	1,651.95	118.41	916.00	3,664.00	n/a	n/a	285.00	252.00	30.80	n/a	n/a	400.00	n/a
2033	1,781.48	118.02	916.00	3,664.00	n/a	n/a	317.00	261.00	30.80	n/a	n/a	400.00	n/a
2034	1,916.63	117.52	916.00	3,664.00	n/a	n/a	348.00	270.00	30.80	n/a	n/a	400.00	n/a
2035	2,075.03	117.01	916.00	3,664.00	n/a	n/a	377.00	272.00	30.80	n/a	n/a	400.00	n/a
2036	2,264.40	116.40	916.00	3,664.00	n/a	n/a	404.00	287.00	30.80	n/a	n/a	400.00	n/a
2037	2,454.08	67.75	975.00	3,900.00	n/a	n/a	429.00	296.00	30.80	n/a	n/a	400.00	n/a
2038	2,631.79	41.47	1,075.00	4,300.00	n/a	n/a	452.00	303.00	30.80	n/a	n/a	400.00	n/a
2039	2,811.35	16.93	1,175.00	4,700.00	n/a	n/a	471.00	310.00	30.80	n/a	n/a	400.00	n/a
2040	2,960.40	16.93	1,275.00	5,100.00	n/a	n/a	487.00	306.00	30.80	n/a	n/a	400.00	n/a
2041	3,145.01	16.93	1,275.00	5,100.00	n/a	n/a	503.00	314.00	30.80	n/a	n/a	400.00	n/a
2042	3,232.38	16.93	1,275.00	5,100.00	n/a	n/a	514.00	330.00	30.80	n/a	n/a	400.00	n/a
2043	3,320.52	16.93	1,275.00	5,100.00	n/a	n/a	523.00	336.00	30.80	n/a	n/a	400.00	n/a

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual goals for actions over the study period

UM 2225 Order Summary/Rubric references: C.2(a)-(i), C.3

								Note: This column reflects both the EE that was previously deemed cost effective by Energy Trust and any additional EE selected in this portfolio	Note: this column reflects both the DR that was previously deemed cost effective by PGE and any additional DR selected in this portfolio					
14	Portfolio14	Unconstrained Tx												
	Clean energy resources (MWa)	Clean energy resources (MWa)	Energy Storage (MW)	Energy Storage (MWh)	Energy Storage (MW)	Energy Storage (MWh)				CBREs (MWa)	CBREs (MW or MWa)			
Year	System resources	Voluntary programs	System resources	System resources	Voluntary programs	Voluntary programs	Energy Efficiency (MWa)	Demand Response (MW)		System resources	Voluntary programs	Retirements (list unit)	Transmission Projects	Operational Changes
2023	n/a	85.49	n/a	n/a	n/a	n/a	n/a	n/a		n/a	n/a	n/a	n/a	n/a
2024	138.60	112.47	-	-	n/a	n/a	30.00	133.00		-	n/a	n/a	-	n/a
2025	138.60	113.21	475.00	1,900.00	n/a	n/a	60.00	162.00		-	n/a	n/a	-	n/a
2026	801.09	114.47	699.00	2,796.00	n/a	n/a	90.00	183.00		-	n/a	n/a	-	n/a
2027	812.79	115.74	828.00	3,312.00	n/a	n/a	120.00	199.00		-	n/a	n/a	-	n/a
2028	1,098.78	116.89	828.00	3,312.00	n/a	n/a	150.00	211.00		-	n/a	n/a	-	n/a
2029	1,292.46	118.28	828.00	3,312.00	n/a	n/a	183.00	218.00		-	n/a	n/a	-	n/a
2030	1,443.87	119.55	828.00	3,312.00	n/a	n/a	216.00	228.00		-	n/a	n/a	-	n/a
2031	1,652.62	119.04	850.00	3,400.00	n/a	n/a	251.00	242.00		-	n/a	n/a	-	n/a
2032	1,781.94	118.41	850.00	3,400.00	n/a	n/a	285.00	252.00		-	n/a	n/a	-	n/a
2033	1,912.79	118.02	939.00	3,756.00	n/a	n/a	317.00	261.00		-	n/a	n/a	-	n/a
2034	2,032.89	117.52	1,039.00	4,156.00	n/a	n/a	348.00	270.00		-	n/a	n/a	-	n/a
2035	2,198.26	117.01	1,075.00	4,300.00	n/a	n/a	377.00	272.00		-	n/a	n/a	-	n/a
2036	2,377.32	116.40	1,075.00	4,300.00	n/a	n/a	404.00	287.00		-	n/a	n/a	-	n/a
2037	2,486.45	67.75	1,075.00	4,300.00	n/a	n/a	429.00	296.00		-	n/a	n/a	-	n/a
2038	2,662.79	41.47	1,075.00	4,300.00	n/a	n/a	452.00	303.00		-	n/a	n/a	-	n/a
2039	2,842.31	16.93	1,175.00	4,700.00	n/a	n/a	471.00	310.00		-	n/a	n/a	-	n/a
2040	3,091.33	16.93	1,275.00	5,100.00	n/a	n/a	487.00	306.00		-	n/a	n/a	-	n/a
2041	3,176.00	16.93	1,275.00	5,100.00	n/a	n/a	503.00	314.00		-	n/a	n/a	-	n/a
2042	3,265.03	16.93	1,275.00	5,100.00	n/a	n/a	514.00	330.00		-	n/a	n/a	-	n/a
2043	3,354.10	16.93	1,275.00	5,100.00	n/a	n/a	523.00	336.00		-	n/a	n/a	-	n/a

15	Portfolio15	No Upgrades												
	Clean energy resources (MWa)	Clean energy resources (MWa)	Energy Storage (MW)	Energy Storage (MWh)	Energy Storage (MW)	Energy Storage (MWh)				CBREs (MWa)	CBREs (MW or MWa)			
Year	System resources	Voluntary programs	System resources	System resources	Voluntary programs	Voluntary programs	Energy Efficiency (MWa)	Demand Response (MW)		System resources	Voluntary programs	Retirements (list unit)	Transmission Projects	Operational Changes
2023	n/a	85.49	n/a	n/a	n/a	n/a	n/a	n/a		n/a	n/a	n/a	n/a	n/a
2024	138.60	112.47	-	-	n/a	n/a	30.00	133.00		-	n/a	n/a	-	n/a
2025	138.61	113.21	475.00	1,900.00	n/a	n/a	60.00	162.00		-	n/a	n/a	-	n/a
2026	633.41	114.47	475.00	1,900.00	n/a	n/a	90.00	183.00		12.55	n/a	n/a	-	n/a
2027	695.07	115.74	475.00	1,900.00	n/a	n/a	120.00	199.00		16.03	n/a	n/a	-	n/a
2028	972.16	116.89	475.00	1,900.00	n/a	n/a	150.00	211.00		21.59	n/a	n/a	-	n/a
2029	1,237.96	118.28	475.00	1,900.00	n/a	n/a	183.00	218.00		26.79	n/a	n/a	-	n/a
2030	1,414.98	119.55	975.00	3,900.00	n/a	n/a	216.00	228.00		30.80	n/a	n/a	-	n/a
2031	1,523.35	119.04	975.00	3,900.00	n/a	n/a	251.00	242.00		30.80	n/a	n/a	-	n/a
2032	1,652.81	118.41	975.00	3,900.00	n/a	n/a	285.00	252.00		30.80	n/a	n/a	-	n/a
2033	1,782.30	118.02	975.00	3,900.00	n/a	n/a	317.00	261.00		30.80	n/a	n/a	-	n/a
2034	1,917.46	117.52	975.00	3,900.00	n/a	n/a	348.00	270.00		30.80	n/a	n/a	-	n/a
2035	2,075.03	117.01	975.00	3,900.00	n/a	n/a	377.00	272.00		30.80	n/a	n/a	-	n/a
2036	2,264.54	116.40	975.00	3,900.00	n/a	n/a	404.00	287.00		30.80	n/a	n/a	-	n/a
2037	2,454.09	67.75	975.00	3,900.00	n/a	n/a	429.00	296.00		30.80	n/a	n/a	-	n/a
2038	2,631.80	41.47	1,075.00	4,300.00	n/a	n/a	452.00	303.00		30.80	n/a	n/a	-	n/a
2039	2,811.36	16.93	1,175.00	4,700.00	n/a	n/a	471.00	310.00		30.80	n/a	n/a	-	n/a
2040	2,960.40	16.93	1,275.00	5,100.00	n/a	n/a	487.00	306.00		30.80	n/a	n/a	-	n/a
2041	3,145.02	16.93	1,275.00	5,100.00	n/a	n/a	503.00	314.00		30.80	n/a	n/a	-	n/a
2042	3,232.39	16.93	1,275.00	5,100.00	n/a	n/a	514.00	330.00		30.80	n/a	n/a	-	n/a
2043	3,320.52	16.93	1,275.00	5,100.00	n/a	n/a	523.00	336.00		30.80	n/a	n/a	-	n/a

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual goals for actions over the study period

UM 2225 Order Summary/Rubric references: C.2(a)-(i), C.3

	16	Portfolio16	Unconstrained SoA											
		Clean energy resources (MWa)	Clean energy resources (MWa)	Energy Storage (MW)	Energy Storage (MWh)	Energy Storage (MW)	Energy Storage (MWh)			CBREs (MWa)	CBREs (MW or MWa)			
Year		System resources	Voluntary programs	System resources	System resources	Voluntary programs	Voluntary programs	Energy Efficiency (MWa)	Demand Response (MW)	System resources	Voluntary programs	Retirements (list unit)	Transmission Projects	Operational Changes
2023		n/a	85.49	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2024		138.60	112.47	-	-	n/a	n/a	30.00	133.00	-	n/a	n/a	-	n/a
2025		138.61	113.21	475.00	1,900.00	n/a	n/a	60.00	162.00	-	n/a	n/a	-	n/a
2026		589.19	114.47	707.00	2,828.00	n/a	n/a	90.00	183.00	12.54	n/a	n/a	-	n/a
2027		695.08	115.74	707.00	2,828.00	n/a	n/a	120.00	199.00	16.00	n/a	n/a	238.00	n/a
2028		975.53	116.89	707.00	2,828.00	n/a	n/a	150.00	211.00	21.56	n/a	n/a	894.00	n/a
2029		1,295.58	118.28	707.00	2,828.00	n/a	n/a	183.00	218.00	26.75	n/a	n/a	1,640.00	n/a
2030		1,418.50	119.55	707.00	2,828.00	n/a	n/a	216.00	228.00	30.75	n/a	n/a	1,940.00	n/a
2031		1,583.93	119.04	707.00	2,828.00	n/a	n/a	251.00	242.00	30.75	n/a	n/a	2,317.00	n/a
2032		1,682.31	118.41	707.00	2,828.00	n/a	n/a	285.00	252.00	30.75	n/a	n/a	2,644.00	n/a
2033		1,838.53	118.02	807.00	3,228.00	n/a	n/a	317.00	261.00	30.75	n/a	n/a	3,017.00	n/a
2034		2,000.11	117.52	907.00	3,628.00	n/a	n/a	348.00	270.00	30.75	n/a	n/a	3,516.00	n/a
2035		2,166.60	117.01	1,007.00	4,028.00	n/a	n/a	377.00	272.00	30.75	n/a	n/a	3,917.00	n/a
2036		2,346.56	116.40	1,075.00	4,300.00	n/a	n/a	404.00	287.00	30.76	n/a	n/a	4,504.00	n/a
2037		2,455.66	67.75	1,075.00	4,300.00	n/a	n/a	429.00	296.00	30.76	n/a	n/a	4,752.00	n/a
2038		2,632.01	41.47	1,075.00	4,300.00	n/a	n/a	452.00	303.00	30.76	n/a	n/a	5,486.00	n/a
2039		2,811.56	16.93	1,175.00	4,700.00	n/a	n/a	471.00	310.00	30.76	n/a	n/a	6,262.00	n/a
2040		3,060.55	16.93	1,275.00	5,100.00	n/a	n/a	487.00	306.00	30.76	n/a	n/a	7,380.00	n/a
2041		3,145.21	16.93	1,275.00	5,100.00	n/a	n/a	503.00	314.00	30.76	n/a	n/a	7,567.00	n/a
2042		3,232.55	16.93	1,275.00	5,100.00	n/a	n/a	514.00	330.00	30.76	n/a	n/a	7,776.00	n/a
2043		3,320.71	16.93	1,275.00	5,100.00	n/a	n/a	523.00	336.00	30.76	n/a	n/a	7,991.00	n/a

	17	Portfolio17	Unconstrained SoA Plus											
		Clean energy resources (MWa)	Clean energy resources (MWa)	Energy Storage (MW)	Energy Storage (MWh)	Energy Storage (MW)	Energy Storage (MWh)			CBREs (MWa)	CBREs (MW or MWa)			
Year		System resources	Voluntary programs	System resources	System resources	Voluntary programs	Voluntary programs	Energy Efficiency (MWa)	Demand Response (MW)	System resources	Voluntary programs	Retirements (list unit)	Transmission Projects	Operational Changes
2023		n/a	85.49	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2024		138.60	112.47	-	-	n/a	n/a	30.00	133.00	-	n/a	n/a	-	n/a
2025		138.60	113.21	475.00	1,900.00	n/a	n/a	60.00	162.00	-	n/a	n/a	-	n/a
2026		589.19	114.47	707.00	2,828.00	n/a	n/a	90.00	183.00	12.54	n/a	n/a	-	n/a
2027		695.08	115.74	707.00	2,828.00	n/a	n/a	120.00	199.00	16.00	n/a	n/a	238.00	n/a
2028		975.53	116.89	707.00	2,828.00	n/a	n/a	150.00	211.00	21.56	n/a	n/a	888.00	n/a
2029		1,288.67	118.28	707.00	2,828.00	n/a	n/a	183.00	218.00	26.75	n/a	n/a	1,622.00	n/a
2030		1,411.40	119.55	707.00	2,828.00	n/a	n/a	216.00	228.00	30.75	n/a	n/a	1,922.00	n/a
2031		1,577.59	119.04	707.00	2,828.00	n/a	n/a	251.00	242.00	30.75	n/a	n/a	2,300.00	n/a
2032		1,667.82	118.41	707.00	2,828.00	n/a	n/a	285.00	252.00	30.75	n/a	n/a	2,614.00	n/a
2033		1,860.27	118.02	775.00	3,100.00	n/a	n/a	317.00	261.00	30.75	n/a	n/a	3,070.00	n/a
2034		1,991.69	117.52	875.00	3,500.00	n/a	n/a	348.00	270.00	30.75	n/a	n/a	3,512.00	n/a
2035		2,139.51	117.01	975.00	3,900.00	n/a	n/a	377.00	272.00	30.75	n/a	n/a	3,881.00	n/a
2036		2,306.29	116.40	1,075.00	4,300.00	n/a	n/a	404.00	287.00	30.76	n/a	n/a	4,447.00	n/a
2037		2,460.32	67.75	1,075.00	4,300.00	n/a	n/a	429.00	296.00	30.76	n/a	n/a	5,058.00	n/a
2038		2,632.02	41.47	1,075.00	4,300.00	n/a	n/a	452.00	303.00	30.76	n/a	n/a	5,825.00	n/a
2039		2,811.57	16.93	1,175.00	4,700.00	n/a	n/a	471.00	310.00	30.76	n/a	n/a	6,510.00	n/a
2040		3,060.59	16.93	1,275.00	5,100.00	n/a	n/a	487.00	306.00	30.76	n/a	n/a	7,192.00	n/a
2041		3,145.24	16.93	1,275.00	5,100.00	n/a	n/a	503.00	314.00	30.76	n/a	n/a	7,380.00	n/a
2042		3,232.58	16.93	1,275.00	5,100.00	n/a	n/a	514.00	330.00	30.76	n/a	n/a	7,589.00	n/a
2043		3,320.73	16.93	1,275.00	5,100.00	n/a	n/a	523.00	336.00	30.76	n/a	n/a	7,804.00	n/a

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual goals for actions over the study period

UM 2225 Order Summary/Rubric references: C.2(a)-(i), C.3

								Note: This column reflects both the EE that was previously deemed cost effective by Energy Trust and any additional EE selected in this portfolio	Note: this column reflects both the DR that was previously deemed cost effective by PGE and any additional DR selected in this portfolio					
18	Portfolio18	SoA in 2027								CBREs (MWa)	CBREs (MW or MWa)			
Year	Clean energy resources (MWa) System resources	Clean energy resources (MWa) Voluntary programs	Energy Storage (MW) System resources	Energy Storage (MWh) System resources	Energy Storage (MW) Voluntary programs	Energy Storage (MWh) Voluntary programs	Energy Efficiency (MWa)	Demand Response (MW)	System resources	Voluntary programs	Retirements (list unit)	Transmission Projects	Operational Changes
2023	n/a	85.49	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2024	138.60	112.47	-	-	n/a	n/a	30.00	133.00	-	n/a	n/a	-	n/a
2025	138.61	113.21	475.00	1,900.00	n/a	n/a	60.00	162.00	-	n/a	n/a	-	n/a
2026	633.42	114.47	475.00	1,900.00	n/a	n/a	90.00	183.00	12.55	n/a	n/a	-	n/a
2027	806.90	115.74	475.00	1,900.00	n/a	n/a	120.00	199.00	16.01	n/a	n/a	400.00	n/a
2028	972.18	116.89	475.00	1,900.00	n/a	n/a	150.00	211.00	21.57	n/a	n/a	400.00	n/a
2029	1,237.96	118.28	475.00	1,900.00	n/a	n/a	183.00	218.00	26.77	n/a	n/a	400.00	n/a
2030	1,412.73	119.55	816.00	3,264.00	n/a	n/a	216.00	228.00	30.80	n/a	n/a	400.00	n/a
2031	1,522.55	119.04	916.00	3,664.00	n/a	n/a	251.00	242.00	30.80	n/a	n/a	400.00	n/a
2032	1,651.95	118.41	916.00	3,664.00	n/a	n/a	285.00	252.00	30.80	n/a	n/a	400.00	n/a
2033	1,781.48	118.02	916.00	3,664.00	n/a	n/a	317.00	261.00	30.80	n/a	n/a	400.00	n/a
2034	1,916.63	117.52	916.00	3,664.00	n/a	n/a	348.00	270.00	30.80	n/a	n/a	400.00	n/a
2035	2,075.03	117.01	916.00	3,664.00	n/a	n/a	377.00	272.00	30.80	n/a	n/a	400.00	n/a
2036	2,264.40	116.40	916.00	3,664.00	n/a	n/a	404.00	287.00	30.80	n/a	n/a	400.00	n/a
2037	2,454.08	67.75	975.00	3,900.00	n/a	n/a	429.00	296.00	30.80	n/a	n/a	400.00	n/a
2038	2,631.79	41.47	1,075.00	4,300.00	n/a	n/a	452.00	303.00	30.80	n/a	n/a	400.00	n/a
2039	2,811.35	16.93	1,175.00	4,700.00	n/a	n/a	471.00	310.00	30.80	n/a	n/a	400.00	n/a
2040	2,960.40	16.93	1,275.00	5,100.00	n/a	n/a	487.00	306.00	30.80	n/a	n/a	400.00	n/a
2041	3,145.01	16.93	1,275.00	5,100.00	n/a	n/a	503.00	314.00	30.80	n/a	n/a	400.00	n/a
2042	3,232.38	16.93	1,275.00	5,100.00	n/a	n/a	514.00	330.00	30.80	n/a	n/a	400.00	n/a
2043	3,320.52	16.93	1,275.00	5,100.00	n/a	n/a	523.00	336.00	30.80	n/a	n/a	400.00	n/a

19	Portfolio19	SoA in 2029							CBREs (MWa)	CBREs (MW or MWa)			
Year	Clean energy resources (MWa) System resources	Clean energy resources (MWa) Voluntary programs	Energy Storage (MW) System resources	Energy Storage (MWh) System resources	Energy Storage (MW) Voluntary programs	Energy Storage (MWh) Voluntary programs	Energy Efficiency (MWa)	Demand Response (MW)	System resources	Voluntary programs	Retirements (list unit)	Transmission Projects	Operational Changes
2023	n/a	85.49	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2024	138.60	112.47	-	-	n/a	n/a	30.00	133.00	-	n/a	n/a	-	n/a
2025	138.61	113.21	475.00	1,900.00	n/a	n/a	60.00	162.00	-	n/a	n/a	-	n/a
2026	633.42	114.47	475.00	1,900.00	n/a	n/a	90.00	183.00	12.54	n/a	n/a	-	n/a
2027	695.09	115.74	475.00	1,900.00	n/a	n/a	120.00	199.00	16.02	n/a	n/a	-	n/a
2028	972.16	116.89	475.00	1,900.00	n/a	n/a	150.00	211.00	21.59	n/a	n/a	-	n/a
2029	1,237.95	118.28	475.00	1,900.00	n/a	n/a	183.00	218.00	26.78	n/a	n/a	400.00	n/a
2030	1,412.73	119.55	816.00	3,264.00	n/a	n/a	216.00	228.00	30.80	n/a	n/a	400.00	n/a
2031	1,522.55	119.04	916.00	3,664.00	n/a	n/a	251.00	242.00	30.80	n/a	n/a	400.00	n/a
2032	1,651.95	118.41	916.00	3,664.00	n/a	n/a	285.00	252.00	30.80	n/a	n/a	400.00	n/a
2033	1,781.48	118.02	916.00	3,664.00	n/a	n/a	317.00	261.00	30.80	n/a	n/a	400.00	n/a
2034	1,916.63	117.52	916.00	3,664.00	n/a	n/a	348.00	270.00	30.80	n/a	n/a	400.00	n/a
2035	2,075.03	117.01	916.00	3,664.00	n/a	n/a	377.00	272.00	30.80	n/a	n/a	400.00	n/a
2036	2,264.40	116.40	916.00	3,664.00	n/a	n/a	404.00	287.00	30.80	n/a	n/a	400.00	n/a
2037	2,454.08	67.75	975.00	3,900.00	n/a	n/a	429.00	296.00	30.80	n/a	n/a	400.00	n/a
2038	2,631.79	41.47	1,075.00	4,300.00	n/a	n/a	452.00	303.00	30.80	n/a	n/a	400.00	n/a
2039	2,811.36	16.93	1,175.00	4,700.00	n/a	n/a	471.00	310.00	30.80	n/a	n/a	400.00	n/a
2040	2,960.40	16.93	1,275.00	5,100.00	n/a	n/a	487.00	306.00	30.80	n/a	n/a	400.00	n/a
2041	3,145.01	16.93	1,275.00	5,100.00	n/a	n/a	503.00	314.00	30.80	n/a	n/a	400.00	n/a
2042	3,232.39	16.93	1,275.00	5,100.00	n/a	n/a	514.00	330.00	30.80	n/a	n/a	400.00	n/a
2043	3,320.52	16.93	1,275.00	5,100.00	n/a	n/a	523.00	336.00	30.80	n/a	n/a	400.00	n/a

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual goals for actions over the study period

UM 2225 Order Summary/Rubric references: C.2(a)-(i), C.3

Note: This column reflects both the EE that was previously deemed cost effective by Energy Trust and any additional EE selected in this portfolio

Note: this column reflects both the DR that was previously deemed cost effective by PGE and any additional DR selected in this portfolio

20	Portfolio20	WY in 2026											
	Clean energy resources (MWa)	Clean energy resources (MWa)	Energy Storage (MW)	Energy Storage (MWh)	Energy Storage (MW)	Energy Storage (MWh)			CBREs (MWa)	CBREs (MW or MWa)			
Year	System resources	Voluntary programs	System resources	System resources	Voluntary programs	Voluntary programs	Energy Efficiency (MWa)	Demand Response (MW)	System resources	Voluntary programs	Retirements (list unit)	Transmission Projects	Operational Changes
2023	n/a	85.49	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2024	138.60	112.47	-	-	n/a	n/a	30.00	133.00	-	n/a	n/a	-	n/a
2025	138.61	113.21	475.00	1,900.00	n/a	n/a	60.00	162.00	-	n/a	n/a	-	n/a
2026	724.98	114.47	475.00	1,900.00	n/a	n/a	90.00	183.00	12.54	n/a	n/a	400.00	n/a
2027	726.08	115.74	475.00	1,900.00	n/a	n/a	120.00	199.00	16.00	n/a	n/a	400.00	n/a
2028	972.18	116.89	475.00	1,900.00	n/a	n/a	150.00	211.00	21.56	n/a	n/a	400.00	n/a
2029	1,237.96	118.28	475.00	1,900.00	n/a	n/a	183.00	218.00	26.77	n/a	n/a	400.00	n/a
2030	1,409.78	119.55	607.00	2,428.00	n/a	n/a	216.00	228.00	30.80	n/a	n/a	400.00	n/a
2031	1,519.72	119.04	707.00	2,828.00	n/a	n/a	251.00	242.00	30.80	n/a	n/a	400.00	n/a
2032	1,650.35	118.41	807.00	3,228.00	n/a	n/a	285.00	252.00	30.80	n/a	n/a	400.00	n/a
2033	1,780.93	118.02	875.00	3,500.00	n/a	n/a	317.00	261.00	30.80	n/a	n/a	400.00	n/a
2034	1,916.05	117.52	875.00	3,500.00	n/a	n/a	348.00	270.00	30.80	n/a	n/a	400.00	n/a
2035	2,075.03	117.01	875.00	3,500.00	n/a	n/a	377.00	272.00	30.80	n/a	n/a	400.00	n/a
2036	2,264.39	116.40	875.00	3,500.00	n/a	n/a	404.00	287.00	30.80	n/a	n/a	400.00	n/a
2037	2,454.08	67.75	975.00	3,900.00	n/a	n/a	429.00	296.00	30.80	n/a	n/a	400.00	n/a
2038	2,631.79	41.47	1,075.00	4,300.00	n/a	n/a	452.00	303.00	30.80	n/a	n/a	400.00	n/a
2039	2,811.35	16.93	1,175.00	4,700.00	n/a	n/a	471.00	310.00	30.80	n/a	n/a	400.00	n/a
2040	2,960.39	16.93	1,275.00	5,100.00	n/a	n/a	487.00	306.00	30.80	n/a	n/a	400.00	n/a
2041	3,145.02	16.93	1,275.00	5,100.00	n/a	n/a	503.00	314.00	30.80	n/a	n/a	400.00	n/a
2042	3,232.39	16.93	1,275.00	5,100.00	n/a	n/a	514.00	330.00	30.80	n/a	n/a	400.00	n/a
2043	3,320.52	16.93	1,275.00	5,100.00	n/a	n/a	523.00	336.00	30.80	n/a	n/a	400.00	n/a

21	Portfolio21	NV in 2026											
	Clean energy resources (MWa)	Clean energy resources (MWa)	Energy Storage (MW)	Energy Storage (MWh)	Energy Storage (MW)	Energy Storage (MWh)			CBREs (MWa)	CBREs (MW or MWa)			
Year	System resources	Voluntary programs	System resources	System resources	Voluntary programs	Voluntary programs	Energy Efficiency (MWa)	Demand Response (MW)	System resources	Voluntary programs	Retirements (list unit)	Transmission Projects	Operational Changes
2023	n/a	85.49	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2024	138.60	112.47	-	-	n/a	n/a	30.00	133.00	-	n/a	n/a	-	n/a
2025	138.61	113.21	475.00	1,900.00	n/a	n/a	60.00	162.00	-	n/a	n/a	-	n/a
2026	674.91	114.47	475.00	1,900.00	n/a	n/a	90.00	183.00	12.54	n/a	n/a	400.00	n/a
2027	691.75	115.74	475.00	1,900.00	n/a	n/a	120.00	199.00	16.00	n/a	n/a	400.00	n/a
2028	972.16	116.89	475.00	1,900.00	n/a	n/a	150.00	211.00	21.56	n/a	n/a	400.00	n/a
2029	1,237.95	118.28	475.00	1,900.00	n/a	n/a	183.00	218.00	26.76	n/a	n/a	400.00	n/a
2030	1,409.78	119.55	607.00	2,428.00	n/a	n/a	216.00	228.00	30.79	n/a	n/a	400.00	n/a
2031	1,519.72	119.04	707.00	2,828.00	n/a	n/a	251.00	242.00	30.80	n/a	n/a	400.00	n/a
2032	1,650.35	118.41	807.00	3,228.00	n/a	n/a	285.00	252.00	30.80	n/a	n/a	400.00	n/a
2033	1,780.93	118.02	875.00	3,500.00	n/a	n/a	317.00	261.00	30.80	n/a	n/a	400.00	n/a
2034	1,916.05	117.52	875.00	3,500.00	n/a	n/a	348.00	270.00	30.80	n/a	n/a	400.00	n/a
2035	2,075.04	117.01	875.00	3,500.00	n/a	n/a	377.00	272.00	30.80	n/a	n/a	400.00	n/a
2036	2,264.25	116.40	875.00	3,500.00	n/a	n/a	404.00	287.00	30.80	n/a	n/a	400.00	n/a
2037	2,454.09	67.75	975.00	3,900.00	n/a	n/a	429.00	296.00	30.80	n/a	n/a	400.00	n/a
2038	2,631.80	41.47	1,075.00	4,300.00	n/a	n/a	452.00	303.00	30.80	n/a	n/a	400.00	n/a
2039	2,811.35	16.93	1,175.00	4,700.00	n/a	n/a	471.00	310.00	30.80	n/a	n/a	400.00	n/a
2040	2,960.40	16.93	1,275.00	5,100.00	n/a	n/a	487.00	306.00	30.80	n/a	n/a	400.00	n/a
2041	3,145.02	16.93	1,275.00	5,100.00	n/a	n/a	503.00	314.00	30.80	n/a	n/a	400.00	n/a
2042	3,232.39	16.93	1,275.00	5,100.00	n/a	n/a	514.00	330.00	30.80	n/a	n/a	400.00	n/a
2043	3,320.52	16.93	1,275.00	5,100.00	n/a	n/a	523.00	336.00	30.80	n/a	n/a	400.00	n/a

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual goals for actions over the study period

UM 2225 Order Summary/Rubric references: C.2(a)-(i), C.3

Note: This column reflects both the EE that was previously deemed cost effective by Energy Trust and any additional EE selected in this portfolio

Note: this column reflects both the DR that was previously deemed cost effective by PGE and any additional DR selected in this portfolio

22 Portfolio22 WY in 2028

Year	Clean energy resources (MWa) System resources	Clean energy resources (MWa) Voluntary programs	Energy Storage (MW) System resources	Energy Storage (MWh) System resources	Energy Storage (MW) Voluntary programs	Energy Storage (MWh) Voluntary programs	Energy Efficiency (MWa)	Demand Response (MW)	CBREs (MWa) System resources	CBREs (MW or MWa) Voluntary programs	Retirements (list unit)	Transmission Projects	Operational Changes
2023	n/a	85.49	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2024	138.60	112.47	-	-	n/a	n/a	30.00	133.00	-	n/a	n/a	-	n/a
2025	138.61	113.21	475.00	1,900.00	n/a	n/a	60.00	162.00	-	n/a	n/a	-	n/a
2026	633.42	114.47	475.00	1,900.00	n/a	n/a	90.00	183.00	12.54	n/a	n/a	-	n/a
2027	696.48	115.74	475.00	1,900.00	n/a	n/a	120.00	199.00	16.01	n/a	n/a	-	n/a
2028	972.16	116.89	475.00	1,900.00	n/a	n/a	150.00	211.00	21.57	n/a	n/a	400.00	n/a
2029	1,237.96	118.28	475.00	1,900.00	n/a	n/a	183.00	218.00	26.77	n/a	n/a	400.00	n/a
2030	1,409.78	119.55	607.00	2,428.00	n/a	n/a	216.00	228.00	30.80	n/a	n/a	400.00	n/a
2031	1,519.72	119.04	707.00	2,828.00	n/a	n/a	251.00	242.00	30.80	n/a	n/a	400.00	n/a
2032	1,650.35	118.41	807.00	3,228.00	n/a	n/a	285.00	252.00	30.80	n/a	n/a	400.00	n/a
2033	1,780.93	118.02	875.00	3,500.00	n/a	n/a	317.00	261.00	30.80	n/a	n/a	400.00	n/a
2034	1,916.05	117.52	875.00	3,500.00	n/a	n/a	348.00	270.00	30.80	n/a	n/a	400.00	n/a
2035	2,075.04	117.01	875.00	3,500.00	n/a	n/a	377.00	272.00	30.80	n/a	n/a	400.00	n/a
2036	2,264.39	116.40	875.00	3,500.00	n/a	n/a	404.00	287.00	30.80	n/a	n/a	400.00	n/a
2037	2,454.08	67.75	975.00	3,900.00	n/a	n/a	429.00	296.00	30.80	n/a	n/a	400.00	n/a
2038	2,631.79	41.47	1,075.00	4,300.00	n/a	n/a	452.00	303.00	30.80	n/a	n/a	400.00	n/a
2039	2,811.35	16.93	1,175.00	4,700.00	n/a	n/a	471.00	310.00	30.80	n/a	n/a	400.00	n/a
2040	2,960.40	16.93	1,275.00	5,100.00	n/a	n/a	487.00	306.00	30.80	n/a	n/a	400.00	n/a
2041	3,145.02	16.93	1,275.00	5,100.00	n/a	n/a	503.00	314.00	30.80	n/a	n/a	400.00	n/a
2042	3,232.39	16.93	1,275.00	5,100.00	n/a	n/a	514.00	330.00	30.80	n/a	n/a	400.00	n/a
2043	3,320.52	16.93	1,275.00	5,100.00	n/a	n/a	523.00	336.00	30.80	n/a	n/a	400.00	n/a

23 Portfolio23 NV in 2028

Year	Clean energy resources (MWa) System resources	Clean energy resources (MWa) Voluntary programs	Energy Storage (MW) System resources	Energy Storage (MWh) System resources	Energy Storage (MW) Voluntary programs	Energy Storage (MWh) Voluntary programs	Energy Efficiency (MWa)	Demand Response (MW)	CBREs (MWa) System resources	CBREs (MW or MWa) Voluntary programs	Retirements (list unit)	Transmission Projects	Operational Changes
2023	n/a	85.49	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2024	138.60	112.47	-	-	n/a	n/a	30.00	133.00	-	n/a	n/a	-	n/a
2025	138.61	113.21	475.00	1,900.00	n/a	n/a	60.00	162.00	-	n/a	n/a	-	n/a
2026	633.41	114.47	475.00	1,900.00	n/a	n/a	90.00	183.00	12.55	n/a	n/a	-	n/a
2027	695.10	115.74	475.00	1,900.00	n/a	n/a	120.00	199.00	16.01	n/a	n/a	-	n/a
2028	972.16	116.89	475.00	1,900.00	n/a	n/a	150.00	211.00	21.57	n/a	n/a	400.00	n/a
2029	1,237.95	118.28	475.00	1,900.00	n/a	n/a	183.00	218.00	26.77	n/a	n/a	400.00	n/a
2030	1,409.78	119.55	607.00	2,428.00	n/a	n/a	216.00	228.00	30.79	n/a	n/a	400.00	n/a
2031	1,519.72	119.04	707.00	2,828.00	n/a	n/a	251.00	242.00	30.80	n/a	n/a	400.00	n/a
2032	1,650.35	118.41	807.00	3,228.00	n/a	n/a	285.00	252.00	30.80	n/a	n/a	400.00	n/a
2033	1,780.93	118.02	875.00	3,500.00	n/a	n/a	317.00	261.00	30.80	n/a	n/a	400.00	n/a
2034	1,916.05	117.52	875.00	3,500.00	n/a	n/a	348.00	270.00	30.80	n/a	n/a	400.00	n/a
2035	2,075.04	117.01	875.00	3,500.00	n/a	n/a	377.00	272.00	30.80	n/a	n/a	400.00	n/a
2036	2,264.25	116.40	875.00	3,500.00	n/a	n/a	404.00	287.00	30.80	n/a	n/a	400.00	n/a
2037	2,454.09	67.75	975.00	3,900.00	n/a	n/a	429.00	296.00	30.80	n/a	n/a	400.00	n/a
2038	2,631.80	41.47	1,075.00	4,300.00	n/a	n/a	452.00	303.00	30.80	n/a	n/a	400.00	n/a
2039	2,811.35	16.93	1,175.00	4,700.00	n/a	n/a	471.00	310.00	30.80	n/a	n/a	400.00	n/a
2040	2,960.40	16.93	1,275.00	5,100.00	n/a	n/a	487.00	306.00	30.80	n/a	n/a	400.00	n/a
2041	3,145.02	16.93	1,275.00	5,100.00	n/a	n/a	503.00	314.00	30.80	n/a	n/a	400.00	n/a
2042	3,232.39	16.93	1,275.00	5,100.00	n/a	n/a	514.00	330.00	30.80	n/a	n/a	400.00	n/a
2043	3,320.52	16.93	1,275.00	5,100.00	n/a	n/a	523.00	336.00	30.80	n/a	n/a	400.00	n/a

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual goals for actions over the study period

UM 2225 Order Summary/Rubric references: C.2(a)-(i), C.3

Note: This column reflects both the EE that was previously deemed cost effective by Energy Trust and any additional EE selected in this portfolio

Note: this column reflects both the DR that was previously deemed cost effective by PGE and any additional DR selected in this portfolio

24	Portfolio24	Oregon-only resources											
	Clean energy resources (MWa)	Clean energy resources (MWa)	Energy Storage (MW)	Energy Storage (MWh)	Energy Storage (MW)	Energy Storage (MWh)			CBREs (MWa)	CBREs (MW or MWa)			
Year	System resources	Voluntary programs	System resources	System resources	Voluntary programs	Voluntary programs	Energy Efficiency (MWa)	Demand Response (MW)	System resources	Voluntary programs	Retirements (list unit)	Transmission Projects	Operational Changes
2023	n/a	85.49	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2024	138.60	112.47	-	-	n/a	n/a	30.00	133.00	-	n/a	n/a	-	n/a
2025	138.61	113.21	475.00	1,900.00	n/a	n/a	60.00	162.00	-	n/a	n/a	-	n/a
2026	633.43	114.47	475.00	1,900.00	n/a	n/a	90.00	183.00	12.54	n/a	n/a	-	n/a
2027	743.16	115.74	475.00	1,900.00	n/a	n/a	120.00	199.00	16.00	n/a	n/a	250.00	n/a
2028	972.17	116.89	475.00	1,900.00	n/a	n/a	150.00	211.00	21.56	n/a	n/a	400.00	n/a
2029	1,237.94	118.28	475.00	1,900.00	n/a	n/a	183.00	218.00	26.77	n/a	n/a	400.00	n/a
2030	1,414.95	119.55	975.00	3,900.00	n/a	n/a	216.00	228.00	30.80	n/a	n/a	400.00	n/a
2031	1,523.34	119.04	975.00	3,900.00	n/a	n/a	251.00	242.00	30.80	n/a	n/a	400.00	n/a
2032	1,652.78	118.41	975.00	3,900.00	n/a	n/a	285.00	252.00	30.80	n/a	n/a	400.00	n/a
2033	1,782.27	118.02	975.00	3,900.00	n/a	n/a	317.00	261.00	30.80	n/a	n/a	400.00	n/a
2034	1,917.45	117.52	975.00	3,900.00	n/a	n/a	348.00	270.00	30.80	n/a	n/a	400.00	n/a
2035	2,075.03	117.01	975.00	3,900.00	n/a	n/a	377.00	272.00	30.80	n/a	n/a	400.00	n/a
2036	2,264.29	116.40	975.00	3,900.00	n/a	n/a	404.00	287.00	30.80	n/a	n/a	400.00	n/a
2037	2,454.06	67.75	975.00	3,900.00	n/a	n/a	429.00	296.00	30.80	n/a	n/a	400.00	n/a
2038	2,631.78	41.47	1,075.00	4,300.00	n/a	n/a	452.00	303.00	30.80	n/a	n/a	400.00	n/a
2039	2,811.33	16.93	1,175.00	4,700.00	n/a	n/a	471.00	310.00	30.80	n/a	n/a	400.00	n/a
2040	2,960.37	16.93	1,275.00	5,100.00	n/a	n/a	487.00	306.00	30.80	n/a	n/a	400.00	n/a
2041	3,145.00	16.93	1,275.00	5,100.00	n/a	n/a	503.00	314.00	30.80	n/a	n/a	400.00	n/a
2042	3,232.36	16.93	1,275.00	5,100.00	n/a	n/a	514.00	330.00	30.80	n/a	n/a	400.00	n/a
2043	3,320.50	16.93	1,275.00	5,100.00	n/a	n/a	523.00	336.00	30.80	n/a	n/a	400.00	n/a

25	Portfolio25	Physical RPS											
	Clean energy resources (MWa)	Clean energy resources (MWa)	Energy Storage (MW)	Energy Storage (MWh)	Energy Storage (MW)	Energy Storage (MWh)			CBREs (MWa)	CBREs (MW or MWa)			
Year	System resources	Voluntary programs	System resources	System resources	Voluntary programs	Voluntary programs	Energy Efficiency (MWa)	Demand Response (MW)	System resources	Voluntary programs	Retirements (list unit)	Transmission Projects	Operational Changes
2023	n/a	85.49	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2024	138.60	112.47	-	-	n/a	n/a	30.00	133.00	-	n/a	n/a	-	n/a
2025	138.61	113.21	475.00	1,900.00	n/a	n/a	60.00	162.00	-	n/a	n/a	-	n/a
2026	633.42	114.47	475.00	1,900.00	n/a	n/a	90.00	183.00	12.54	n/a	n/a	-	n/a
2027	734.27	115.74	475.00	1,900.00	n/a	n/a	120.00	199.00	16.01	n/a	n/a	228.00	n/a
2028	972.18	116.89	475.00	1,900.00	n/a	n/a	150.00	211.00	21.56	n/a	n/a	400.00	n/a
2029	1,237.96	118.28	475.00	1,900.00	n/a	n/a	183.00	218.00	26.77	n/a	n/a	400.00	n/a
2030	1,412.73	119.55	816.00	3,264.00	n/a	n/a	216.00	228.00	30.80	n/a	n/a	400.00	n/a
2031	1,522.55	119.04	916.00	3,664.00	n/a	n/a	251.00	242.00	30.80	n/a	n/a	400.00	n/a
2032	1,651.95	118.41	916.00	3,664.00	n/a	n/a	285.00	252.00	30.80	n/a	n/a	400.00	n/a
2033	1,781.48	118.02	916.00	3,664.00	n/a	n/a	317.00	261.00	30.80	n/a	n/a	400.00	n/a
2034	1,916.63	117.52	916.00	3,664.00	n/a	n/a	348.00	270.00	30.80	n/a	n/a	400.00	n/a
2035	2,075.03	117.01	916.00	3,664.00	n/a	n/a	377.00	272.00	30.80	n/a	n/a	400.00	n/a
2036	2,264.40	116.40	916.00	3,664.00	n/a	n/a	404.00	287.00	30.80	n/a	n/a	400.00	n/a
2037	2,454.08	67.75	975.00	3,900.00	n/a	n/a	429.00	296.00	30.80	n/a	n/a	400.00	n/a
2038	2,631.79	41.47	1,075.00	4,300.00	n/a	n/a	452.00	303.00	30.80	n/a	n/a	400.00	n/a
2039	2,811.35	16.93	1,175.00	4,700.00	n/a	n/a	471.00	310.00	30.80	n/a	n/a	400.00	n/a
2040	2,960.40	16.93	1,275.00	5,100.00	n/a	n/a	487.00	306.00	30.80	n/a	n/a	400.00	n/a
2041	3,145.01	16.93	1,275.00	5,100.00	n/a	n/a	503.00	314.00	30.80	n/a	n/a	400.00	n/a
2042	3,232.38	16.93	1,275.00	5,100.00	n/a	n/a	514.00	330.00	30.80	n/a	n/a	400.00	n/a
2043	3,320.52	16.93	1,275.00	5,100.00	n/a	n/a	523.00	336.00	30.80	n/a	n/a	400.00	n/a

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual goals for actions over the study period

UM 2225 Order Summary/Rubric references: C.2(a)-(i), C.3

Note: This column reflects both the EE that was previously deemed cost effective by Energy Trust and any additional EE selected in this portfolio

Note: this column reflects both the DR that was previously deemed cost effective by PGE and any additional DR selected in this portfolio

26	Portfolio26	Hydrogen blending											
	Clean energy resources (MWa)	Clean energy resources (MWa)	Energy Storage (MW)	Energy Storage (MWh)	Energy Storage (MW)	Energy Storage (MWh)			CBREs (MWa)	CBREs (MW or MWa)			
Year	System resources	Voluntary programs	System resources	System resources	Voluntary programs	Voluntary programs	Energy Efficiency (MWa)	Demand Response (MW)	System resources	Voluntary programs	Retirements (list unit)	Transmission Projects	Operational Changes
2023	n/a	85.49	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2024	138.60	112.47	-	-	n/a	n/a	30.00	133.00	rush,	n/a	n/a	-	n/a
2025	138.61	113.21	475.00	1,900.00	n/a	n/a	60.00	162.00	-	n/a	n/a	-	n/a
2026	633.42	114.47	475.00	1,900.00	n/a	n/a	90.00	183.00	12.54	n/a	n/a	-	n/a
2027	734.27	115.74	475.00	1,900.00	n/a	n/a	120.00	199.00	16.01	n/a	n/a	228.00	n/a
2028	972.18	116.89	475.00	1,900.00	n/a	n/a	150.00	211.00	21.56	n/a	n/a	400.00	n/a
2029	1,125.96	118.28	475.00	1,900.00	n/a	n/a	183.00	218.00	26.76	n/a	n/a	400.00	n/a
2030	1,303.22	119.55	921.00	3,684.00	n/a	n/a	216.00	228.00	30.79	n/a	n/a	400.00	n/a
2031	1,413.35	119.04	975.00	3,900.00	n/a	n/a	251.00	242.00	30.80	n/a	n/a	400.00	n/a
2032	1,549.81	118.41	975.00	3,900.00	n/a	n/a	285.00	252.00	30.80	n/a	n/a	400.00	n/a
2033	1,682.29	118.02	975.00	3,900.00	n/a	n/a	317.00	261.00	30.80	n/a	n/a	400.00	n/a
2034	1,821.46	117.52	975.00	3,900.00	n/a	n/a	348.00	270.00	30.80	n/a	n/a	400.00	n/a
2035	2,012.42	117.01	975.00	3,900.00	n/a	n/a	377.00	272.00	30.80	n/a	n/a	400.00	n/a
2036	2,201.78	116.40	975.00	3,900.00	n/a	n/a	404.00	287.00	30.80	n/a	n/a	400.00	n/a
2037	2,391.47	67.75	975.00	3,900.00	n/a	n/a	429.00	296.00	30.80	n/a	n/a	400.00	n/a
2038	2,580.29	41.47	1,075.00	4,300.00	n/a	n/a	452.00	303.00	30.80	n/a	n/a	400.00	n/a
2039	2,770.81	16.93	1,175.00	4,700.00	n/a	n/a	471.00	310.00	30.80	n/a	n/a	400.00	n/a
2040	2,960.40	16.93	1,275.00	5,100.00	n/a	n/a	487.00	306.00	30.80	n/a	n/a	400.00	n/a
2041	3,145.01	16.93	1,275.00	5,100.00	n/a	n/a	503.00	314.00	30.80	n/a	n/a	400.00	n/a
2042	3,232.38	16.93	1,275.00	5,100.00	n/a	n/a	514.00	330.00	30.80	n/a	n/a	400.00	n/a
2043	3,320.52	16.93	1,275.00	5,100.00	n/a	n/a	523.00	336.00	30.80	n/a	n/a	400.00	n/a

27	Portfolio27	Hydrogen building											
	Clean energy resources (MWa)	Clean energy resources (MWa)	Energy Storage (MW)	Energy Storage (MWh)	Energy Storage (MW)	Energy Storage (MWh)			CBREs (MWa)	CBREs (MW or MWa)			
Year	System resources	Voluntary programs	System resources	System resources	Voluntary programs	Voluntary programs	Energy Efficiency (MWa)	Demand Response (MW)	System resources	Voluntary programs	Retirements (list unit)	Transmission Projects	Operational Changes
2023	n/a	85.49	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2024	138.60	112.47	-	-	n/a	n/a	30.00	133.00	-	n/a	n/a	-	n/a
2025	138.61	113.21	475.00	1,900.00	n/a	n/a	60.00	162.00	-	n/a	n/a	-	n/a
2026	633.43	114.47	475.00	1,900.00	n/a	n/a	90.00	183.00	12.54	n/a	n/a	-	n/a
2027	734.29	115.74	475.00	1,900.00	n/a	n/a	120.00	199.00	16.01	n/a	n/a	228.00	n/a
2028	972.18	116.89	475.00	1,900.00	n/a	n/a	150.00	211.00	21.56	n/a	n/a	400.00	n/a
2029	1,237.95	118.28	475.00	1,900.00	n/a	n/a	183.00	218.00	26.77	n/a	n/a	400.00	n/a
2030	1,409.77	119.55	607.00	2,428.00	n/a	n/a	216.00	228.00	30.80	n/a	n/a	400.00	n/a
2031	1,519.72	119.04	707.00	2,828.00	n/a	n/a	251.00	242.00	30.80	n/a	n/a	400.00	n/a
2032	1,650.37	118.41	807.00	3,228.00	n/a	n/a	285.00	252.00	30.80	n/a	n/a	400.00	n/a
2033	1,780.93	118.02	875.00	3,500.00	n/a	n/a	317.00	261.00	30.80	n/a	n/a	400.00	n/a
2034	1,916.05	117.52	875.00	3,500.00	n/a	n/a	348.00	270.00	30.80	n/a	n/a	400.00	n/a
2035	2,074.15	117.01	875.00	3,500.00	n/a	n/a	377.00	272.00	30.80	n/a	n/a	400.00	n/a
2036	2,263.67	116.40	875.00	3,500.00	n/a	n/a	404.00	287.00	30.80	n/a	n/a	400.00	n/a
2037	2,454.07	67.75	975.00	3,900.00	n/a	n/a	429.00	296.00	30.80	n/a	n/a	400.00	n/a
2038	2,631.80	41.47	1,075.00	4,300.00	n/a	n/a	452.00	303.00	30.80	n/a	n/a	400.00	n/a
2039	2,811.36	16.93	1,175.00	4,700.00	n/a	n/a	471.00	310.00	30.80	n/a	n/a	400.00	n/a
2040	2,960.40	16.93	1,275.00	5,100.00	n/a	n/a	487.00	306.00	30.80	n/a	n/a	400.00	n/a
2041	3,145.01	16.93	1,275.00	5,100.00	n/a	n/a	503.00	314.00	30.80	n/a	n/a	400.00	n/a
2042	3,232.39	16.93	1,275.00	5,100.00	n/a	n/a	514.00	330.00	30.80	n/a	n/a	400.00	n/a
2043	3,320.53	16.93	1,275.00	5,100.00	n/a	n/a	523.00	336.00	30.80	n/a	n/a	400.00	n/a

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual goals for actions over the study period

UM 2225 Order Summary/Rubric references: C.2(a)-(i), C.3

28	Portfolio28	Offshore wind												
	Clean energy resources (MWa)	Clean energy resources (MWa)	Energy Storage (MW)	Energy Storage (MWh)	Energy Storage (MW)	Energy Storage (MWh)			CBREs (MWa)	CBREs (MW or MWa)				
Year	System resources	Voluntary programs	System resources	System resources	Voluntary programs	Voluntary programs	Energy Efficiency (MWa)	Demand Response (MW)	System resources	Voluntary programs	Retirements (list unit)	Transmission Projects	Operational Changes	
2023	n/a	85.49	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	
2024	138.60	112.47	-	-	n/a	n/a	30.00	133.00	-	n/a	n/a	-	n/a	
2025	138.60	113.21	475.00	1,900.00	n/a	n/a	60.00	162.00	-	n/a	n/a	-	n/a	
2026	633.41	114.47	475.00	1,900.00	n/a	n/a	90.00	183.00	12.54	n/a	n/a	-	n/a	
2027	734.24	115.74	475.00	1,900.00	n/a	n/a	120.00	199.00	16.01	n/a	n/a	228.00	n/a	
2028	972.19	116.89	475.00	1,900.00	n/a	n/a	150.00	211.00	21.56	n/a	n/a	400.00	n/a	
2029	1,237.95	118.28	475.00	1,900.00	n/a	n/a	183.00	218.00	26.77	n/a	n/a	400.00	n/a	
2030	1,412.73	119.55	816.00	3,264.00	n/a	n/a	216.00	228.00	30.80	n/a	n/a	400.00	n/a	
2031	1,480.10	119.04	916.00	3,664.00	n/a	n/a	251.00	242.00	30.80	n/a	n/a	400.00	n/a	
2032	1,753.45	118.41	1,016.00	4,064.00	n/a	n/a	285.00	252.00	30.80	n/a	n/a	400.00	n/a	
2033	1,782.91	118.02	1,016.00	4,064.00	n/a	n/a	317.00	261.00	30.80	n/a	n/a	400.00	n/a	
2034	1,918.09	117.52	1,016.00	4,064.00	n/a	n/a	348.00	270.00	30.80	n/a	n/a	400.00	n/a	
2035	2,075.66	117.01	1,016.00	4,064.00	n/a	n/a	377.00	272.00	30.80	n/a	n/a	400.00	n/a	
2036	2,265.11	116.40	1,016.00	4,064.00	n/a	n/a	404.00	287.00	30.80	n/a	n/a	400.00	n/a	
2037	2,454.69	67.75	1,016.00	4,064.00	n/a	n/a	429.00	296.00	30.80	n/a	n/a	400.00	n/a	
2038	2,631.85	41.47	1,075.00	4,300.00	n/a	n/a	452.00	303.00	30.80	n/a	n/a	400.00	n/a	
2039	2,811.40	16.93	1,175.00	4,700.00	n/a	n/a	471.00	310.00	30.80	n/a	n/a	400.00	n/a	
2040	2,960.45	16.93	1,275.00	5,100.00	n/a	n/a	487.00	306.00	30.80	n/a	n/a	400.00	n/a	
2041	3,145.08	16.93	1,275.00	5,100.00	n/a	n/a	503.00	314.00	30.80	n/a	n/a	400.00	n/a	
2042	3,232.43	16.93	1,275.00	5,100.00	n/a	n/a	514.00	330.00	30.80	n/a	n/a	400.00	n/a	
2043	3,320.59	16.93	1,275.00	5,100.00	n/a	n/a	523.00	336.00	30.80	n/a	n/a	400.00	n/a	

29	Portfolio29	Long Duration Storage												
	Clean energy resources (MWa)	Clean energy resources (MWa)	Energy Storage (MW)	Energy Storage (MWh)	Energy Storage (MW)	Energy Storage (MWh)			CBREs (MWa)	CBREs (MW or MWa)				
Year	System resources	Voluntary programs	System resources	System resources	Voluntary programs	Voluntary programs	Energy Efficiency (MWa)	Demand Response (MW)	System resources	Voluntary programs	Retirements (list unit)	Transmission Projects	Operational Changes	
2023	n/a	85.49	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	
2024	138.60	112.47	-	-	n/a	n/a	30.00	133.00	-	n/a	n/a	-	n/a	
2025	138.61	113.21	475.00	1,900.00	n/a	n/a	60.00	162.00	-	n/a	n/a	-	n/a	
2026	633.44	114.47	475.00	1,900.00	n/a	n/a	90.00	183.00	12.54	n/a	n/a	-	n/a	
2027	734.29	115.74	475.00	1,900.00	n/a	n/a	120.00	199.00	16.01	n/a	n/a	228.00	n/a	
2028	977.74	116.89	614.00	5,236.00	n/a	n/a	150.00	211.00	21.56	n/a	n/a	400.00	n/a	
2029	1,243.68	118.28	614.00	5,236.00	n/a	n/a	183.00	218.00	26.77	n/a	n/a	400.00	n/a	
2030	1,415.86	119.55	747.00	5,236.00	n/a	n/a	216.00	228.00	30.80	n/a	n/a	400.00	n/a	
2031	1,525.55	119.04	847.00	5,236.00	n/a	n/a	251.00	242.00	30.80	n/a	n/a	400.00	n/a	
2032	1,656.44	118.41	947.00	5,236.00	n/a	n/a	285.00	252.00	30.80	n/a	n/a	400.00	n/a	
2033	1,787.08	118.02	1,014.00	5,236.00	n/a	n/a	317.00	261.00	30.80	n/a	n/a	400.00	n/a	
2034	1,922.48	117.52	1,014.00	5,236.00	n/a	n/a	348.00	270.00	30.80	n/a	n/a	400.00	n/a	
2035	2,080.79	117.01	1,014.00	5,236.00	n/a	n/a	377.00	272.00	30.80	n/a	n/a	400.00	n/a	
2036	2,270.15	116.40	1,014.00	5,236.00	n/a	n/a	404.00	287.00	30.80	n/a	n/a	400.00	n/a	
2037	2,459.83	67.75	1,114.00	5,236.00	n/a	n/a	429.00	296.00	30.80	n/a	n/a	400.00	n/a	
2038	2,637.35	41.47	1,214.00	5,236.00	n/a	n/a	452.00	303.00	30.80	n/a	n/a	400.00	n/a	
2039	2,817.18	16.93	1,314.00	5,236.00	n/a	n/a	471.00	310.00	30.80	n/a	n/a	400.00	n/a	
2040	2,966.61	16.93	1,414.00	5,236.00	n/a	n/a	487.00	306.00	30.80	n/a	n/a	400.00	n/a	
2041	3,151.06	16.93	1,414.00	5,236.00	n/a	n/a	503.00	314.00	30.80	n/a	n/a	400.00	n/a	
2042	3,238.86	16.93	1,414.00	5,236.00	n/a	n/a	514.00	330.00	30.80	n/a	n/a	400.00	n/a	
2043	3,326.89	16.93	1,414.00	5,236.00	n/a	n/a	523.00	336.00	30.80	n/a	n/a	400.00	n/a	

Note: This column reflects both the EE that was previously deemed cost effective by Energy Trust and any additional EE selected in this portfolio

Note: this column reflects both the DR that was previously deemed cost effective by PGE and any additional DR selected in this portfolio

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual goals for actions over the study period

UM 2225 Order Summary/Rubric references: C.2(a)-(i), C.3

Note: This column reflects both the EE that was previously deemed cost effective by Energy Trust and any additional EE selected in this portfolio

Note: this column reflects both the DR that was previously deemed cost effective by PGE and any additional DR selected in this portfolio

30 Portfolio30 Pumped hydro

Year	Clean energy resources (MWa) System resources	Clean energy resources (MWa) Voluntary programs	Energy Storage (MW) System resources	Energy Storage (MWh) System resources	Energy Storage (MW) Voluntary programs	Energy Storage (MWh) Voluntary programs	Energy Efficiency (MWa)	Demand Response (MW)	CBREs (MWa) System resources	CBREs (MW or MWa) Voluntary programs	Retirements (list unit)	Transmission Projects	Operational Changes
2023	n/a	85.49	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2024	138.60	112.47	-	-	n/a	n/a	30.00	133.00	-	n/a	n/a	-	n/a
2025	138.61	113.21	475.00	1,900.00	n/a	n/a	60.00	162.00	-	n/a	n/a	-	n/a
2026	633.44	114.47	475.00	1,900.00	n/a	n/a	90.00	183.00	12.54	n/a	n/a	-	n/a
2027	734.30	115.74	475.00	1,900.00	n/a	n/a	120.00	199.00	16.01	n/a	n/a	228.00	n/a
2028	983.78	116.89	808.00	5,230.00	n/a	n/a	150.00	211.00	21.56	n/a	n/a	400.00	n/a
2029	1,249.76	118.28	808.00	5,230.00	n/a	n/a	183.00	218.00	26.76	n/a	n/a	400.00	n/a
2030	1,423.14	119.55	941.00	5,762.00	n/a	n/a	216.00	228.00	30.79	n/a	n/a	400.00	n/a
2031	1,532.48	119.04	1,041.00	6,162.00	n/a	n/a	251.00	242.00	30.80	n/a	n/a	400.00	n/a
2032	1,663.98	118.41	1,141.00	6,562.00	n/a	n/a	285.00	252.00	30.80	n/a	n/a	400.00	n/a
2033	1,795.45	118.02	1,208.00	6,830.00	n/a	n/a	317.00	261.00	30.80	n/a	n/a	400.00	n/a
2034	1,931.44	117.52	1,208.00	6,830.00	n/a	n/a	348.00	270.00	30.80	n/a	n/a	400.00	n/a
2035	2,088.10	117.01	1,208.00	6,830.00	n/a	n/a	377.00	272.00	30.80	n/a	n/a	400.00	n/a
2036	2,277.46	116.40	1,208.00	6,830.00	n/a	n/a	404.00	287.00	30.80	n/a	n/a	400.00	n/a
2037	2,467.14	67.75	1,308.00	7,230.00	n/a	n/a	429.00	296.00	30.80	n/a	n/a	400.00	n/a
2038	2,644.88	41.47	1,408.00	7,630.00	n/a	n/a	452.00	303.00	30.80	n/a	n/a	400.00	n/a
2039	2,824.64	16.93	1,508.00	8,030.00	n/a	n/a	471.00	310.00	30.80	n/a	n/a	400.00	n/a
2040	2,974.86	16.93	1,608.00	8,430.00	n/a	n/a	487.00	306.00	30.80	n/a	n/a	400.00	n/a
2041	3,159.53	16.93	1,608.00	8,430.00	n/a	n/a	503.00	314.00	30.80	n/a	n/a	400.00	n/a
2042	3,248.48	16.93	1,608.00	8,430.00	n/a	n/a	514.00	330.00	30.80	n/a	n/a	400.00	n/a
2043	3,336.08	16.93	1,608.00	8,430.00	n/a	n/a	523.00	336.00	30.80	n/a	n/a	400.00	n/a

31 Portfolio31 RTO

Year	Clean energy resources (MWa) System resources	Clean energy resources (MWa) Voluntary programs	Energy Storage (MW) System resources	Energy Storage (MWh) System resources	Energy Storage (MW) Voluntary programs	Energy Storage (MWh) Voluntary programs	Energy Efficiency (MWa)	Demand Response (MW)	CBREs (MWa) System resources	CBREs (MW or MWa) Voluntary programs	Retirements (list unit)	Transmission Projects	Operational Changes
2023	n/a	85.49	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2024	138.60	112.47	-	-	n/a	n/a	30.00	133.00	-	n/a	n/a	-	n/a
2025	138.61	113.21	475.00	1,900.00	n/a	n/a	60.00	162.00	-	n/a	n/a	-	n/a
2026	633.42	114.47	475.00	1,900.00	n/a	n/a	90.00	183.00	12.54	n/a	n/a	-	n/a
2027	734.27	115.74	475.00	1,900.00	n/a	n/a	120.00	199.00	16.01	n/a	n/a	228.00	n/a
2028	972.18	116.89	475.00	1,900.00	n/a	n/a	150.00	211.00	21.56	n/a	n/a	400.00	n/a
2029	1,237.96	118.28	475.00	1,900.00	n/a	n/a	183.00	218.00	26.77	n/a	n/a	400.00	n/a
2030	1,412.73	119.55	816.00	3,264.00	n/a	n/a	216.00	228.00	30.80	n/a	n/a	400.00	n/a
2031	1,522.55	119.04	916.00	3,664.00	n/a	n/a	251.00	242.00	30.80	n/a	n/a	400.00	n/a
2032	1,651.95	118.41	916.00	3,664.00	n/a	n/a	285.00	252.00	30.80	n/a	n/a	400.00	n/a
2033	1,781.48	118.02	916.00	3,664.00	n/a	n/a	317.00	261.00	30.80	n/a	n/a	400.00	n/a
2034	1,916.63	117.52	916.00	3,664.00	n/a	n/a	348.00	270.00	30.80	n/a	n/a	400.00	n/a
2035	2,075.03	117.01	916.00	3,664.00	n/a	n/a	377.00	272.00	30.80	n/a	n/a	400.00	n/a
2036	2,264.40	116.40	916.00	3,664.00	n/a	n/a	404.00	287.00	30.80	n/a	n/a	400.00	n/a
2037	2,454.08	67.75	975.00	3,900.00	n/a	n/a	429.00	296.00	30.80	n/a	n/a	400.00	n/a
2038	2,631.79	41.47	1,075.00	4,300.00	n/a	n/a	452.00	303.00	30.80	n/a	n/a	400.00	n/a
2039	2,811.35	16.93	1,175.00	4,700.00	n/a	n/a	471.00	310.00	30.80	n/a	n/a	400.00	n/a
2040	2,960.40	16.93	1,275.00	5,100.00	n/a	n/a	487.00	306.00	30.80	n/a	n/a	400.00	n/a
2041	3,145.01	16.93	1,275.00	5,100.00	n/a	n/a	503.00	314.00	30.80	n/a	n/a	400.00	n/a
2042	3,232.38	16.93	1,275.00	5,100.00	n/a	n/a	514.00	330.00	30.80	n/a	n/a	400.00	n/a
2043	3,320.52	16.93	1,275.00	5,100.00	n/a	n/a	523.00	336.00	30.80	n/a	n/a	400.00	n/a

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual goals for actions over the study period

UM 2225 Order Summary/Rubric references: C.2(a)-(i), C.3

								Note: This column reflects both the EE that was previously deemed cost effective by Energy Trust and any additional EE selected in this portfolio	Note: this column reflects both the DR that was previously deemed cost effective by PGE and any additional DR selected in this portfolio					
32	Portfolio32	Min Avg LT cost												
	Clean energy resources (MWa)	Clean energy resources (MWa)	Energy Storage (MW)	Energy Storage (MWh)	Energy Storage (MW)	Energy Storage (MWh)				CBREs (MWa)	CBREs (MW or MWa)			
Year	System resources	Voluntary programs	System resources	System resources	Voluntary programs	Voluntary programs	Energy Efficiency (MWa)	Demand Response (MW)		System resources	Voluntary programs	Retirements (list unit)	Transmission Projects	Operational Changes
2023	n/a	85.49	n/a	n/a	n/a	n/a	n/a	n/a		n/a	n/a	n/a	n/a	n/a
2024	138.60	112.47	-	-	n/a	n/a	30.00	133.00		-	n/a	n/a	-	n/a
2025	138.61	113.21	475.00	1,900.00	n/a	n/a	60.00	162.00		-	n/a	n/a	-	n/a
2026	633.42	114.47	475.00	1,900.00	n/a	n/a	90.00	183.00		12.54	n/a	n/a	-	n/a
2027	734.27	115.74	475.00	1,900.00	n/a	n/a	120.00	199.00		16.01	n/a	n/a	228.00	n/a
2028	972.18	116.89	475.00	1,900.00	n/a	n/a	150.00	211.00		21.56	n/a	n/a	400.00	n/a
2029	1,237.96	118.28	475.00	1,900.00	n/a	n/a	183.00	218.00		26.77	n/a	n/a	400.00	n/a
2030	1,412.73	119.55	816.00	3,264.00	n/a	n/a	216.00	228.00		30.80	n/a	n/a	400.00	n/a
2031	1,522.55	119.04	916.00	3,664.00	n/a	n/a	251.00	242.00		30.80	n/a	n/a	400.00	n/a
2032	1,651.95	118.41	916.00	3,664.00	n/a	n/a	285.00	252.00		30.80	n/a	n/a	400.00	n/a
2033	1,781.48	118.02	916.00	3,664.00	n/a	n/a	317.00	261.00		30.80	n/a	n/a	400.00	n/a
2034	1,916.63	117.52	916.00	3,664.00	n/a	n/a	348.00	270.00		30.80	n/a	n/a	400.00	n/a
2035	2,075.03	117.01	916.00	3,664.00	n/a	n/a	377.00	272.00		30.80	n/a	n/a	400.00	n/a
2036	2,264.40	116.40	916.00	3,664.00	n/a	n/a	404.00	287.00		30.80	n/a	n/a	400.00	n/a
2037	2,454.08	67.75	975.00	3,900.00	n/a	n/a	429.00	296.00		30.80	n/a	n/a	400.00	n/a
2038	2,631.79	41.47	1,075.00	4,300.00	n/a	n/a	452.00	303.00		30.80	n/a	n/a	400.00	n/a
2039	2,811.35	16.93	1,175.00	4,700.00	n/a	n/a	471.00	310.00		30.80	n/a	n/a	400.00	n/a
2040	2,960.40	16.93	1,275.00	5,100.00	n/a	n/a	487.00	306.00		30.80	n/a	n/a	400.00	n/a
2041	3,145.01	16.93	1,275.00	5,100.00	n/a	n/a	503.00	314.00		30.80	n/a	n/a	400.00	n/a
2042	3,232.38	16.93	1,275.00	5,100.00	n/a	n/a	514.00	330.00		30.80	n/a	n/a	400.00	n/a
2043	3,320.52	16.93	1,275.00	5,100.00	n/a	n/a	523.00	336.00		30.80	n/a	n/a	400.00	n/a

33	Portfolio33	Min Avg ST cost												
	Clean energy resources (MWa)	Clean energy resources (MWa)	Energy Storage (MW)	Energy Storage (MWh)	Energy Storage (MW)	Energy Storage (MWh)				CBREs (MWa)	CBREs (MW or MWa)			
Year	System resources	Voluntary programs	System resources	System resources	Voluntary programs	Voluntary programs	Energy Efficiency (MWa)	Demand Response (MW)		System resources	Voluntary programs	Retirements (list unit)	Transmission Projects	Operational Changes
2023	n/a	85.49	n/a	n/a	n/a	n/a	n/a	n/a		n/a	n/a	n/a	n/a	n/a
2024	138.60	112.47	-	-	n/a	n/a	30.00	133.00		-	n/a	n/a	-	n/a
2025	138.61	113.21	475.00	1,900.00	n/a	n/a	60.00	162.00		-	n/a	n/a	-	n/a
2026	442.55	114.47	649.00	2,596.00	n/a	n/a	90.00	183.00		12.54	n/a	n/a	-	n/a
2027	502.30	115.74	649.00	2,596.00	n/a	n/a	120.00	199.00		16.00	n/a	n/a	137.00	n/a
2028	627.69	116.89	649.00	2,596.00	n/a	n/a	150.00	211.00		21.56	n/a	n/a	253.00	n/a
2029	871.47	118.28	649.00	2,596.00	n/a	n/a	183.00	218.00		26.77	n/a	n/a	400.00	n/a
2030	1,016.00	119.55	684.00	2,736.00	n/a	n/a	216.00	228.00		30.80	n/a	n/a	400.00	n/a
2031	1,116.35	119.04	784.00	3,136.00	n/a	n/a	251.00	242.00		30.80	n/a	n/a	400.00	n/a
2032	1,225.52	118.41	884.00	3,536.00	n/a	n/a	285.00	252.00		30.80	n/a	n/a	400.00	n/a
2033	1,334.43	118.02	984.00	3,936.00	n/a	n/a	317.00	261.00		30.80	n/a	n/a	400.00	n/a
2034	1,443.95	117.52	1,084.00	4,336.00	n/a	n/a	348.00	270.00		30.80	n/a	n/a	400.00	n/a
2035	1,565.72	117.01	1,184.00	4,736.00	n/a	n/a	377.00	272.00		30.80	n/a	n/a	400.00	n/a
2036	1,755.01	116.40	1,275.00	5,100.00	n/a	n/a	404.00	287.00		30.80	n/a	n/a	400.00	n/a
2037	1,899.87	67.75	1,275.00	5,100.00	n/a	n/a	429.00	296.00		30.80	n/a	n/a	400.00	n/a
2038	2,088.99	41.47	1,275.00	5,100.00	n/a	n/a	452.00	303.00		30.80	n/a	n/a	400.00	n/a
2039	2,234.96	16.93	1,275.00	5,100.00	n/a	n/a	471.00	310.00		30.80	n/a	n/a	400.00	n/a
2040	2,424.47	16.93	1,275.00	5,100.00	n/a	n/a	487.00	306.00		30.80	n/a	n/a	400.00	n/a
2041	2,513.33	16.93	1,275.00	5,100.00	n/a	n/a	503.00	314.00		30.80	n/a	n/a	400.00	n/a
2042	2,648.57	16.93	1,275.00	5,100.00	n/a	n/a	514.00	330.00		30.80	n/a	n/a	400.00	n/a
2043	2,647.98	16.93	1,275.00	5,100.00	n/a	n/a	523.00	336.00		30.80	n/a	n/a	400.00	n/a

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual goals for actions over the study period

UM 2225 Order Summary/Rubric references: C.2(a)-(i), C.3

								Note: This column reflects both the EE that was previously deemed cost effective by Energy Trust and any additional EE selected in this portfolio	Note: this column reflects both the DR that was previously deemed cost effective by PGE and any additional DR selected in this portfolio					
34	Portfolio34	Min Ref ST cost												
	Clean energy resources (MWa)	Clean energy resources (MWa)	Energy Storage (MW)	Energy Storage (MWh)	Energy Storage (MW)	Energy Storage (MWh)				CBREs (MWa)	CBREs (MW or MWa)			
Year	System resources	Voluntary programs	System resources	System resources	Voluntary programs	Voluntary programs	Energy Efficiency (MWa)	Demand Response (MW)		System resources	Voluntary programs	Retirements (list unit)	Transmission Projects	Operational Changes
2023	n/a	85.49	n/a	n/a	n/a	n/a	n/a	n/a		n/a	n/a	n/a	n/a	n/a
2024	138.60	112.47	-	-	n/a	n/a	30.00	133.00		-	n/a	n/a	-	n/a
2025	138.61	113.21	475.00	1,900.00	n/a	n/a	60.00	162.00		-	n/a	n/a	-	n/a
2026	675.99	114.47	475.00	1,900.00	n/a	n/a	90.00	183.00		12.54	n/a	n/a	-	n/a
2027	773.28	115.74	475.00	1,900.00	n/a	n/a	120.00	199.00		16.00	n/a	n/a	220.00	n/a
2028	972.22	116.89	475.00	1,900.00	n/a	n/a	150.00	211.00		21.56	n/a	n/a	400.00	n/a
2029	1,237.99	118.28	475.00	1,900.00	n/a	n/a	183.00	218.00		26.77	n/a	n/a	400.00	n/a
2030	1,418.61	119.55	1,231.00	4,924.00	n/a	n/a	216.00	228.00		30.80	n/a	n/a	400.00	n/a
2031	1,627.47	119.04	1,275.00	5,100.00	n/a	n/a	251.00	242.00		30.80	n/a	n/a	400.00	n/a
2032	1,657.29	118.41	1,275.00	5,100.00	n/a	n/a	285.00	252.00		30.80	n/a	n/a	400.00	n/a
2033	1,786.57	118.02	1,275.00	5,100.00	n/a	n/a	317.00	261.00		30.80	n/a	n/a	400.00	n/a
2034	1,975.10	117.52	1,275.00	5,100.00	n/a	n/a	348.00	270.00		30.80	n/a	n/a	400.00	n/a
2035	2,160.07	117.01	1,275.00	5,100.00	n/a	n/a	377.00	272.00		30.80	n/a	n/a	400.00	n/a
2036	2,349.36	116.40	1,275.00	5,100.00	n/a	n/a	404.00	287.00		30.80	n/a	n/a	400.00	n/a
2037	2,539.48	67.75	1,275.00	5,100.00	n/a	n/a	429.00	296.00		30.80	n/a	n/a	400.00	n/a
2038	2,728.56	41.47	1,275.00	5,100.00	n/a	n/a	452.00	303.00		30.80	n/a	n/a	400.00	n/a
2039	2,813.18	16.93	1,275.00	5,100.00	n/a	n/a	471.00	310.00		30.80	n/a	n/a	400.00	n/a
2040	2,960.77	16.93	1,275.00	5,100.00	n/a	n/a	487.00	306.00		30.80	n/a	n/a	400.00	n/a
2041	3,145.40	16.93	1,275.00	5,100.00	n/a	n/a	503.00	314.00		30.80	n/a	n/a	400.00	n/a
2042	3,232.74	16.93	1,275.00	5,100.00	n/a	n/a	514.00	330.00		30.80	n/a	n/a	400.00	n/a
2043	3,320.88	16.93	1,275.00	5,100.00	n/a	n/a	523.00	336.00		30.80	n/a	n/a	400.00	n/a

35	Portfolio35	SoA in 2027 Plus												
	Clean energy resources (MWa)	Clean energy resources (MWa)	Energy Storage (MW)	Energy Storage (MWh)	Energy Storage (MW)	Energy Storage (MWh)				CBREs (MWa)	CBREs (MW or MWa)			
Year	System resources	Voluntary programs	System resources	System resources	Voluntary programs	Voluntary programs	Energy Efficiency (MWa)	Demand Response (MW)		System resources	Voluntary programs	Retirements (list unit)	Transmission Projects	Operational Changes
2023	n/a	85.49	n/a	n/a	n/a	n/a	n/a	n/a		n/a	n/a	n/a	n/a	n/a
2024	138.60	112.47	-	-	n/a	n/a	30.00	133.00		-	n/a	n/a	-	n/a
2025	138.61	113.21	475.00	1,900.00	n/a	n/a	60.00	162.00		-	n/a	n/a	-	n/a
2026	618.32	114.47	475.00	1,900.00	n/a	n/a	90.00	183.00		12.55	n/a	n/a	-	n/a
2027	791.80	115.74	475.00	1,900.00	n/a	n/a	120.00	199.00		16.01	n/a	n/a	400.00	n/a
2028	972.18	116.89	475.00	1,900.00	n/a	n/a	150.00	211.00		21.57	n/a	n/a	400.00	n/a
2029	1,237.95	118.28	475.00	1,900.00	n/a	n/a	183.00	218.00		26.76	n/a	n/a	953.00	n/a
2030	1,407.90	119.55	475.00	1,900.00	n/a	n/a	216.00	228.00		30.78	n/a	n/a	1,200.00	n/a
2031	1,516.56	119.04	475.00	1,900.00	n/a	n/a	251.00	242.00		30.79	n/a	n/a	1,200.00	n/a
2032	1,645.98	118.41	507.00	2,028.00	n/a	n/a	285.00	252.00		30.80	n/a	n/a	1,200.00	n/a
2033	1,777.26	118.02	607.00	2,428.00	n/a	n/a	317.00	261.00		30.80	n/a	n/a	1,200.00	n/a
2034	1,913.67	117.52	707.00	2,828.00	n/a	n/a	348.00	270.00		30.80	n/a	n/a	1,200.00	n/a
2035	2,074.89	117.01	775.00	3,100.00	n/a	n/a	377.00	272.00		30.80	n/a	n/a	1,200.00	n/a
2036	2,263.80	116.40	875.00	3,500.00	n/a	n/a	404.00	287.00		30.80	n/a	n/a	1,200.00	n/a
2037	2,454.08	67.75	975.00	3,900.00	n/a	n/a	429.00	296.00		30.80	n/a	n/a	1,200.00	n/a
2038	2,631.78	41.47	1,075.00	4,300.00	n/a	n/a	452.00	303.00		30.80	n/a	n/a	1,200.00	n/a
2039	2,811.34	16.93	1,175.00	4,700.00	n/a	n/a	471.00	310.00		30.80	n/a	n/a	1,200.00	n/a
2040	2,960.38	16.93	1,275.00	5,100.00	n/a	n/a	487.00	306.00		30.80	n/a	n/a	1,200.00	n/a
2041	3,145.01	16.93	1,275.00	5,100.00	n/a	n/a	503.00	314.00		30.80	n/a	n/a	1,200.00	n/a
2042	3,232.37	16.93	1,275.00	5,100.00	n/a	n/a	514.00	330.00		30.80	n/a	n/a	1,200.00	n/a
2043	3,320.50	16.93	1,275.00	5,100.00	n/a	n/a	523.00	336.00		30.80	n/a	n/a	1,200.00	n/a

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual goals for actions over the study period

UM 2225 Order Summary/Rubric references: C.2(a)-(i), C.3

36	Portfolio36	50 Mwa EE						Note: This column reflects both the EE that was previously deemed cost effective by Energy Trust and any additional EE selected in this portfolio	Note: this column reflects both the DR that was previously deemed cost effective by PGE and any additional DR selected in this portfolio					
	Clean energy resources (MWa)	Clean energy resources (MWa)	Energy Storage (MW)	Energy Storage (MWh)	Energy Storage (MW)	Energy Storage (MWh)			CBREs (MWa)	CBREs (MW or MWa)				
Year	System resources	Voluntary programs	System resources	System resources	Voluntary programs	Voluntary programs	Energy Efficiency (MWa)	Demand Response (MW)	System resources	Voluntary programs	Retirements (list unit)	Transmission Projects	Operational Changes	
2023	n/a	85.49	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	
2024	138.60	112.47	-	-	n/a	n/a	30.00	133.00	-	n/a	n/a	-	n/a	
2025	138.61	113.21	475.00	1,900.00	n/a	n/a	60.00	162.00	-	n/a	n/a	-	n/a	
2026	630.17	114.47	475.00	1,900.00	n/a	n/a	100.06	183.00	12.55	n/a	n/a	-	n/a	
2027	716.16	115.74	475.00	1,900.00	n/a	n/a	140.09	199.00	16.01	n/a	n/a	194.00	n/a	
2028	942.18	116.89	475.00	1,900.00	n/a	n/a	180.12	211.00	21.57	n/a	n/a	400.00	n/a	
2029	1,197.96	118.28	475.00	1,900.00	n/a	n/a	223.15	218.00	26.76	n/a	n/a	400.00	n/a	
2030	1,360.18	119.55	636.00	2,544.00	n/a	n/a	266.18	228.00	30.79	n/a	n/a	400.00	n/a	
2031	1,470.11	119.04	736.00	2,944.00	n/a	n/a	301.23	242.00	30.80	n/a	n/a	400.00	n/a	
2032	1,600.78	118.41	836.00	3,344.00	n/a	n/a	335.28	252.00	30.80	n/a	n/a	400.00	n/a	
2033	1,730.93	118.02	875.00	3,500.00	n/a	n/a	367.33	261.00	30.80	n/a	n/a	400.00	n/a	
2034	1,866.05	117.52	875.00	3,500.00	n/a	n/a	398.38	270.00	30.80	n/a	n/a	400.00	n/a	
2035	2,025.03	117.01	875.00	3,500.00	n/a	n/a	427.43	272.00	30.80	n/a	n/a	400.00	n/a	
2036	2,214.40	116.40	875.00	3,500.00	n/a	n/a	454.48	287.00	30.80	n/a	n/a	400.00	n/a	
2037	2,404.08	67.75	975.00	3,900.00	n/a	n/a	479.53	296.00	30.80	n/a	n/a	400.00	n/a	
2038	2,581.79	41.47	1,075.00	4,300.00	n/a	n/a	502.58	303.00	30.80	n/a	n/a	400.00	n/a	
2039	2,761.36	16.93	1,175.00	4,700.00	n/a	n/a	521.63	310.00	30.80	n/a	n/a	400.00	n/a	
2040	2,910.40	16.93	1,275.00	5,100.00	n/a	n/a	537.68	306.00	30.80	n/a	n/a	400.00	n/a	
2041	3,095.01	16.93	1,275.00	5,100.00	n/a	n/a	553.73	314.00	30.80	n/a	n/a	400.00	n/a	
2042	3,182.39	16.93	1,275.00	5,100.00	n/a	n/a	564.78	330.00	30.80	n/a	n/a	400.00	n/a	
2043	3,270.52	16.93	1,275.00	5,100.00	n/a	n/a	573.83	336.00	30.80	n/a	n/a	400.00	n/a	

37	Portfolio37	25 Mwa EE												
	Clean energy resources (MWa)	Clean energy resources (MWa)	Energy Storage (MW)	Energy Storage (MWh)	Energy Storage (MW)	Energy Storage (MWh)			CBREs (MWa)	CBREs (MW or MWa)				
Year	System resources	Voluntary programs	System resources	System resources	Voluntary programs	Voluntary programs	Energy Efficiency (MWa)	Demand Response (MW)	System resources	Voluntary programs	Retirements (list unit)	Transmission Projects	Operational Changes	
2023	n/a	85.49	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	
2024	138.60	112.47	-	-	n/a	n/a	30.00	133.00	-	n/a	n/a	-	n/a	
2025	138.61	113.21	475.00	1,900.00	n/a	n/a	60.00	162.00	-	n/a	n/a	-	n/a	
2026	631.80	114.47	475.00	1,900.00	n/a	n/a	95.06	183.00	12.55	n/a	n/a	-	n/a	
2027	725.96	115.74	475.00	1,900.00	n/a	n/a	130.09	199.00	16.01	n/a	n/a	213.00	n/a	
2028	957.18	116.89	475.00	1,900.00	n/a	n/a	165.12	211.00	21.57	n/a	n/a	400.00	n/a	
2029	1,217.96	118.28	475.00	1,900.00	n/a	n/a	203.15	218.00	26.77	n/a	n/a	400.00	n/a	
2030	1,385.99	119.55	693.00	2,772.00	n/a	n/a	241.18	228.00	30.80	n/a	n/a	400.00	n/a	
2031	1,495.89	119.04	793.00	3,172.00	n/a	n/a	276.23	242.00	30.80	n/a	n/a	400.00	n/a	
2032	1,626.35	118.41	875.00	3,500.00	n/a	n/a	310.28	252.00	30.80	n/a	n/a	400.00	n/a	
2033	1,755.93	118.02	875.00	3,500.00	n/a	n/a	342.33	261.00	30.80	n/a	n/a	400.00	n/a	
2034	1,891.05	117.52	875.00	3,500.00	n/a	n/a	373.38	270.00	30.80	n/a	n/a	400.00	n/a	
2035	2,050.03	117.01	875.00	3,500.00	n/a	n/a	402.43	272.00	30.80	n/a	n/a	400.00	n/a	
2036	2,239.40	116.40	875.00	3,500.00	n/a	n/a	429.48	287.00	30.80	n/a	n/a	400.00	n/a	
2037	2,429.08	67.75	975.00	3,900.00	n/a	n/a	454.53	296.00	30.80	n/a	n/a	400.00	n/a	
2038	2,606.79	41.47	1,075.00	4,300.00	n/a	n/a	477.58	303.00	30.80	n/a	n/a	400.00	n/a	
2039	2,786.36	16.93	1,175.00	4,700.00	n/a	n/a	496.63	310.00	30.80	n/a	n/a	400.00	n/a	
2040	2,935.40	16.93	1,275.00	5,100.00	n/a	n/a	512.68	306.00	30.80	n/a	n/a	400.00	n/a	
2041	3,120.01	16.93	1,275.00	5,100.00	n/a	n/a	528.73	314.00	30.80	n/a	n/a	400.00	n/a	
2042	3,207.39	16.93	1,275.00	5,100.00	n/a	n/a	539.78	330.00	30.80	n/a	n/a	400.00	n/a	
2043	3,295.52	16.93	1,275.00	5,100.00	n/a	n/a	548.83	336.00	30.80	n/a	n/a	400.00	n/a	

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual goals for actions over the study period

UM 2225 Order Summary/Rubric references: C.2(a)-(i), C.3

38	Portfolio38	70 Mwa EE						Note: This column reflects both the EE that was previously deemed cost effective by Energy Trust and any additional EE selected in this portfolio	Note: this column reflects both the DR that was previously deemed cost effective by PGE and any additional DR selected in this portfolio					
	Clean energy resources (MWa)	Clean energy resources (MWa)	Energy Storage (MW)	Energy Storage (MWh)	Energy Storage (MW)	Energy Storage (MWh)			CBREs (MWa)	CBREs (MW or MWa)				
Year	System resources	Voluntary programs	System resources	System resources	Voluntary programs	Voluntary programs	Energy Efficiency (MWa)	Demand Response (MW)	System resources	Voluntary programs	Retirements (list unit)	Transmission Projects	Operational Changes	
2023	n/a	85.49	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	
2024	138.60	112.47	-	-	n/a	n/a	30.00	133.00	-	n/a	n/a	-	n/a	
2025	138.61	113.21	475.00	1,900.00	n/a	n/a	60.00	162.00	-	n/a	n/a	-	n/a	
2026	628.62	114.47	475.00	1,900.00	n/a	n/a	106.04	183.00	12.55	n/a	n/a	-	n/a	
2027	705.32	115.74	475.00	1,900.00	n/a	n/a	149.05	199.00	16.01	n/a	n/a	173.00	n/a	
2028	930.24	116.89	475.00	1,900.00	n/a	n/a	192.06	211.00	21.57	n/a	n/a	400.00	n/a	
2029	1,181.04	118.28	475.00	1,900.00	n/a	n/a	240.07	218.00	26.76	n/a	n/a	400.00	n/a	
2030	1,339.88	119.55	607.00	2,428.00	n/a	n/a	286.08	228.00	30.79	n/a	n/a	400.00	n/a	
2031	1,449.82	119.04	707.00	2,828.00	n/a	n/a	321.13	242.00	30.80	n/a	n/a	400.00	n/a	
2032	1,580.46	118.41	807.00	3,228.00	n/a	n/a	355.18	252.00	30.80	n/a	n/a	400.00	n/a	
2033	1,711.03	118.02	875.00	3,500.00	n/a	n/a	387.23	261.00	30.80	n/a	n/a	400.00	n/a	
2034	1,846.15	117.52	875.00	3,500.00	n/a	n/a	418.28	270.00	30.80	n/a	n/a	400.00	n/a	
2035	2,005.13	117.01	875.00	3,500.00	n/a	n/a	447.33	272.00	30.80	n/a	n/a	400.00	n/a	
2036	2,194.50	116.40	875.00	3,500.00	n/a	n/a	474.38	287.00	30.80	n/a	n/a	400.00	n/a	
2037	2,384.18	67.75	975.00	3,900.00	n/a	n/a	499.43	296.00	30.80	n/a	n/a	400.00	n/a	
2038	2,561.89	41.47	1,075.00	4,300.00	n/a	n/a	522.48	303.00	30.80	n/a	n/a	400.00	n/a	
2039	2,741.46	16.93	1,175.00	4,700.00	n/a	n/a	541.53	310.00	30.80	n/a	n/a	400.00	n/a	
2040	2,890.50	16.93	1,275.00	5,100.00	n/a	n/a	557.58	306.00	30.80	n/a	n/a	400.00	n/a	
2041	3,075.11	16.93	1,275.00	5,100.00	n/a	n/a	573.63	314.00	30.80	n/a	n/a	400.00	n/a	
2042	3,162.49	16.93	1,275.00	5,100.00	n/a	n/a	584.68	330.00	30.80	n/a	n/a	400.00	n/a	
2043	3,250.62	16.93	1,275.00	5,100.00	n/a	n/a	593.73	336.00	30.80	n/a	n/a	400.00	n/a	

39	Portfolio39	Optimized												
	Clean energy resources (MWa)	Clean energy resources (MWa)	Energy Storage (MW)	Energy Storage (MWh)	Energy Storage (MW)	Energy Storage (MWh)			CBREs (MWa)	CBREs (MW or MWa)				
Year	System resources	Voluntary programs	System resources	System resources	Voluntary programs	Voluntary programs	Energy Efficiency (MWa)	Demand Response (MW)	System resources	Voluntary programs	Retirements (list unit)	Transmission Projects	Operational Changes	
2023	n/a	85.49	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	
2024	138.60	112.47	-	-	n/a	n/a	30.00	133.00	-	n/a	n/a	-	n/a	
2025	138.61	113.21	475.00	1,900.00	n/a	n/a	60.00	162.00	-	n/a	n/a	-	n/a	
2026	629.89	114.47	475.00	1,900.00	n/a	n/a	102.00	183.00	12.50	n/a	n/a	-	n/a	
2027	712.91	115.74	475.00	1,900.00	n/a	n/a	142.00	199.00	15.96	n/a	n/a	187.00	n/a	
2028	940.17	116.89	475.00	1,900.00	n/a	n/a	182.00	211.00	21.53	n/a	n/a	400.00	n/a	
2029	1,194.95	118.28	475.00	1,900.00	n/a	n/a	226.00	218.00	26.73	n/a	n/a	817.00	n/a	
2030	1,354.90	119.55	475.00	1,900.00	n/a	n/a	269.00	228.00	30.76	n/a	n/a	1,171.00	n/a	
2031	1,463.55	119.04	475.00	1,900.00	n/a	n/a	304.00	242.00	30.77	n/a	n/a	1,171.00	n/a	
2032	1,592.51	118.41	475.00	1,900.00	n/a	n/a	338.00	252.00	30.77	n/a	n/a	1,171.00	n/a	
2033	1,723.81	118.02	575.00	2,300.00	n/a	n/a	370.00	261.00	30.78	n/a	n/a	1,171.00	n/a	
2034	1,860.23	117.52	675.00	2,700.00	n/a	n/a	401.00	270.00	30.80	n/a	n/a	1,171.00	n/a	
2035	2,012.62	117.01	775.00	3,100.00	n/a	n/a	430.00	272.00	30.80	n/a	n/a	1,171.00	n/a	
2036	2,201.56	116.40	875.00	3,500.00	n/a	n/a	457.00	287.00	30.80	n/a	n/a	1,171.00	n/a	
2037	2,401.07	67.75	975.00	3,900.00	n/a	n/a	483.00	296.00	30.80	n/a	n/a	1,200.00	n/a	
2038	2,578.79	41.47	1,075.00	4,300.00	n/a	n/a	506.00	303.00	30.80	n/a	n/a	1,200.00	n/a	
2039	2,758.34	16.93	1,175.00	4,700.00	n/a	n/a	525.00	310.00	30.80	n/a	n/a	1,200.00	n/a	
2040	2,907.39	16.93	1,275.00	5,100.00	n/a	n/a	541.00	306.00	30.80	n/a	n/a	1,200.00	n/a	
2041	3,092.02	16.93	1,275.00	5,100.00	n/a	n/a	557.00	314.00	30.80	n/a	n/a	1,200.00	n/a	
2042	3,179.37	16.93	1,275.00	5,100.00	n/a	n/a	568.00	330.00	30.80	n/a	n/a	1,200.00	n/a	
2043	3,267.50	16.93	1,275.00	5,100.00	n/a	n/a	577.00	336.00	30.80	n/a	n/a	1,200.00	n/a	

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual GHG emissions based on the DEQ methodology over the study period under Reference Case assumptions
For each year, break out the contributions of individual fossil fuel resources, market purchases, and market sales to the total GHG emissions per the DEQ methodology
UM 2225 Order Summary/Rubric references: C.4(a)

PGE note: Forecasts of generation from existing thermal output are based on economic dispatch using prices forecasted in this CEP/IRP. Forecasts of unspecified and other emitting market purchases are a function of historical purchases and a linear decline emission reduction glidepath. Neither reflect operational realities.

40	Portfolio40	Preferred		PGE owned GHG emitting generation (retail)					
		Included in retail total	*Not included in retail total*	Beaver	Carty	Coyote	PW1	PW2	Colstrip
Year	Total Retail GHG Emissions (metric tons)	Market Purchases (metric tons)	Market sales (metric tons)	Fossil fuel resource 1 (metric tons)	Fossil fuel resource 2 (metric tons)	Fossil fuel resource 3 (metric tons)	Fossil fuel resource 4 (metric tons)	Fossil fuel resource 5 (metric tons)	Fossil fuel resource 6 (metric tons)
2023	5,887,117	2,351,875	2,097,049	41,539	919,175	509,985	641,895	130,219	1,292,430
2024	5,308,316	1,802,933	1,865,467	137,208	879,158	490,395	635,821	175,051	1,187,749
2025	5,049,607	1,705,195	1,790,077	142,367	837,292	463,866	563,301	176,532	1,161,054
2026	4,363,686	1,366,816	2,265,765	167,981	721,455	393,273	519,881	156,078	1,038,201
2027	3,677,764	1,091,731	2,920,645	222,701	579,927	317,101	480,068	167,172	819,064
2028	2,991,843	811,290	3,817,679	360,534	435,432	240,102	385,570	187,487	571,428
2029	2,305,921	629,845	4,198,793	276,854	338,557	187,835	295,418	144,426	432,985
2030	1,620,000	550,194	2,882,753	231,882	295,412	164,415	256,135	121,962	-
2031	1,458,000	496,626	2,957,038	213,644	262,290	145,762	230,531	109,147	-
2032	1,296,000	461,739	2,823,141	187,525	226,122	127,262	199,112	94,241	-
2033	1,134,000	410,730	2,828,792	158,824	200,937	109,031	171,174	83,304	-
2034	972,000	361,878	2,780,984	136,906	165,578	93,414	144,128	70,096	-
2035	810,000	303,939	2,825,533	109,880	140,332	77,564	120,283	58,001	-
2036	648,000	254,336	2,695,013	78,402	113,496	62,321	95,522	43,923	-
2037	486,000	192,423	2,732,068	66,499	80,170	44,470	68,615	33,822	-
2038	324,000	133,719	2,617,541	40,467	52,898	29,551	46,191	21,175	-
2039	162,000	68,292	2,594,418	18,400	26,833	14,838	23,117	10,520	-
2040	-	-	2,475,750	-	-	-	-	-	-
2041	-	-	2,459,879	-	-	-	-	-	-
2042	-	-	2,209,453	-	-	-	-	-	-
2043	-	-	2,300,472	-	-	-	-	-	-
sources:	GHG model_linear decline: retail CO2	GHG model_linear decline: market gas, market landfill, market waste, market wood, market ACS, market unspecified	GHG model_linear decline: wholesale carbon of thermal plants, market gas, market landfill, market waste, market wood, market ACS, market unspecified	GHG model_linear decline: retail carbon	GHG model_linear decline: retail carbon	GHG model_linear decline: retail carbon	GHG model_linear decline: retail carbon	GHG model_linear decline: retail carbon	GHG model_linear decline: retail carbon

1	Portfolio1	Linear decline		PGE owned GHG emitting generation (retail)					
		Included in retail total	*Not included in retail total*	Beaver	Carty	Coyote	PW1	PW2	Colstrip
Year	Total Retail GHG Emissions (metric tons)	Market Purchases (metric tons)	Market sales (metric tons)	Fossil fuel resource 1 (metric tons)	Fossil fuel resource 2 (metric tons)	Fossil fuel resource 3 (metric tons)	Fossil fuel resource 4 (metric tons)	Fossil fuel resource 5 (metric tons)	Fossil fuel resource 6 (metric tons)
2023	5,887,117	2,351,875	2,097,049	41,539	919,175	509,985	641,895	130,219	1,292,430
2024	5,308,316	1,802,933	1,865,467	137,208	879,158	490,395	635,821	175,051	1,187,749
2025	5,049,607	1,705,195	1,790,077	142,367	837,292	463,866	563,301	176,532	1,161,054
2026	4,363,686	1,366,816	2,265,765	167,981	721,455	393,273	519,881	156,078	1,038,201
2027	3,677,764	1,091,731	2,920,645	222,701	579,927	317,101	480,068	167,172	819,064
2028	2,991,843	811,290	3,817,679	360,534	435,432	240,102	385,570	187,487	571,428
2029	2,305,921	629,845	4,198,793	276,854	338,557	187,835	295,418	144,426	432,985
2030	1,620,000	550,194	2,882,753	231,882	295,412	164,415	256,135	121,962	-
2031	1,458,000	496,626	2,957,038	213,644	262,290	145,762	230,531	109,147	-
2032	1,296,000	461,739	2,823,141	187,525	226,122	127,262	199,112	94,241	-
2033	1,134,000	410,730	2,828,792	158,824	200,937	109,031	171,174	83,304	-
2034	972,000	361,878	2,780,984	136,906	165,578	93,414	144,128	70,096	-
2035	810,000	303,939	2,825,533	109,880	140,332	77,564	120,283	58,001	-
2036	648,000	254,336	2,695,013	78,402	113,496	62,321	95,522	43,923	-
2037	486,000	192,423	2,732,068	66,499	80,170	44,470	68,615	33,822	-
2038	324,000	133,719	2,617,541	40,467	52,898	29,551	46,191	21,175	-
2039	162,000	68,292	2,594,418	18,400	26,833	14,838	23,117	10,520	-
2040	-	-	2,475,750	-	-	-	-	-	-
2041	-	-	2,459,879	-	-	-	-	-	-
2042	-	-	2,209,453	-	-	-	-	-	-
2043	-	-	2,300,472	-	-	-	-	-	-

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual GHG emissions based on the DEQ methodology over the study period under Reference Case assumptions
For each year, break out the contributions of individual fossil fuel resources, market purchases, and market sales to the total GHG emissions per the DEQ methodology
UM 2225 Order Summary/Rubric references: C.4(a)

PGE note: Forecasts of generation from existing thermal output are based on economic dispatch using prices forecasted in this CEP/IRP. Forecasts of unspecified and other emitting market purchases are a function of historical purchases and a linear decline emission reduction glidepath. Neither reflect operational realities.

2	Portfolio2	Front-loaded decline		PGE owned GHG emitting generation (retail)					
		Included in retail total	*Not included in retail total*	Beaver	Carty	Coyote	PW1	PW2	Colstrip
Year	Total Retail GHG Emissions (metric tons)	Market Purchases (metric tons)	Market sales (metric tons)	Fossil fuel resource 1 (metric tons)	Fossil fuel resource 2 (metric tons)	Fossil fuel resource 3 (metric tons)	Fossil fuel resource 4 (metric tons)	Fossil fuel resource 5 (metric tons)	Fossil fuel resource 6 (metric tons)
2023	5,887,117	2,351,875	2,097,049	41,539	919,175	509,985	641,895	130,219	1,292,430
2024	5,308,316	1,802,933	1,865,467	137,208	879,158	490,395	635,821	175,051	1,187,749
2025	5,049,607	1,705,195	1,790,077	142,367	837,292	463,866	563,301	176,532	1,161,054
2026	3,279,487	1,027,218	2,899,475	126,245	542,203	295,561	390,712	117,299	780,250
2027	2,394,427	710,777	3,698,634	144,991	377,565	206,450	312,551	108,838	533,256
2028	1,951,897	529,291	4,483,543	235,214	284,079	156,644	251,548	122,318	372,803
2029	1,730,632	472,709	4,565,636	207,784	254,093	140,973	221,716	108,394	324,963
2030	1,620,000	550,194	2,882,753	231,882	295,412	164,415	256,135	121,962	-
2031	1,458,000	496,626	2,957,038	213,644	262,290	145,762	230,531	109,147	-
2032	1,296,000	461,739	2,823,141	187,525	226,122	127,262	199,112	94,241	-
2033	1,134,000	410,730	2,828,792	158,824	200,937	109,031	171,174	83,304	-
2034	972,000	361,878	2,780,984	136,906	165,578	93,414	144,128	70,096	-
2035	810,000	303,939	2,825,533	109,880	140,332	77,564	120,283	58,001	-
2036	648,000	254,336	2,695,013	78,402	113,496	62,321	95,522	43,923	-
2037	486,000	192,423	2,732,068	66,499	80,170	44,470	68,615	33,822	-
2038	324,000	133,719	2,617,541	40,467	52,898	29,551	46,191	21,175	-
2039	162,000	68,292	2,594,418	18,400	26,833	14,838	23,117	10,520	-
2040	-	-	2,475,750	-	-	-	-	-	-
2041	-	-	2,459,879	-	-	-	-	-	-
2042	-	-	2,209,453	-	-	-	-	-	-
2043	-	-	2,300,472	-	-	-	-	-	-

3	Portfolio3	Back-loaded decline		PGE owned GHG emitting generation (retail)					
		Included in retail total	*Not included in retail total*	Beaver	Carty	Coyote	PW1	PW2	Colstrip
Year	Total Retail GHG Emissions (metric tons)	Market Purchases (metric tons)	Market sales (metric tons)	Fossil fuel resource 1 (metric tons)	Fossil fuel resource 2 (metric tons)	Fossil fuel resource 3 (metric tons)	Fossil fuel resource 4 (metric tons)	Fossil fuel resource 5 (metric tons)	Fossil fuel resource 6 (metric tons)
2023	5,887,117	2,351,875	2,097,049	41,539	919,175	509,985	641,895	130,219	1,292,430
2024	5,308,316	1,802,933	1,865,467	137,208	879,158	490,395	635,821	175,051	1,187,749
2025	5,049,607	1,705,195	1,790,077	142,367	837,292	463,866	563,301	176,532	1,161,054
2026	4,938,974	1,547,011	1,929,510	190,127	816,568	445,120	588,420	176,655	1,175,073
2027	4,717,710	1,400,435	2,290,206	285,673	743,911	406,767	615,815	214,443	1,050,667
2028	4,275,180	1,159,289	2,995,974	515,183	622,209	343,092	550,958	267,909	816,539
2029	3,390,120	925,985	3,507,435	407,026	497,740	276,151	434,318	212,333	636,566
2030	1,620,000	550,194	2,882,753	231,882	295,412	164,415	256,135	121,962	-
2031	1,458,000	496,626	2,957,038	213,644	262,290	145,762	230,531	109,147	-
2032	1,296,000	461,739	2,823,141	187,525	226,122	127,262	199,112	94,241	-
2033	1,134,000	410,730	2,828,792	158,824	200,937	109,031	171,174	83,304	-
2034	972,000	361,878	2,780,984	136,906	165,578	93,414	144,128	70,096	-
2035	810,000	303,939	2,825,533	109,880	140,332	77,564	120,283	58,001	-
2036	648,000	254,336	2,695,013	78,402	113,496	62,321	95,522	43,923	-
2037	486,000	192,423	2,732,068	66,499	80,170	44,470	68,615	33,822	-
2038	324,000	133,719	2,617,541	40,467	52,898	29,551	46,191	21,175	-
2039	162,000	68,292	2,594,418	18,400	26,833	14,838	23,117	10,520	-
2040	-	-	2,475,750	-	-	-	-	-	-
2041	-	-	2,459,879	-	-	-	-	-	-
2042	-	-	2,209,453	-	-	-	-	-	-
2043	-	-	2,300,472	-	-	-	-	-	-

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual GHG emissions based on the DEQ methodology over the study period under Reference Case assumptions
For each year, break out the contributions of individual fossil fuel resources, market purchases, and market sales to the total GHG emissions per the DEQ methodology
UM 2225 Order Summary/Rubric references: C.4(a)

PGE note: Forecasts of generation from existing thermal output are based on economic dispatch using prices forecasted in this CEP/IRP. Forecasts of unspecified and other emitting market purchases are a function of historical purchases and a linear decline emission reduction glidepath. Neither reflect operational realities.

4	Portfolio4	100% emissions reduction by 2035		PGE owned GHG emitting generation (retail)					
	Included in retail total	*Not included in retail total*		Beaver	Carty	Coyote	PW1	PW2	Colstrip
Year	Total Retail GHG Emissions (metric tons)	Market Purchases (metric tons)	Market sales (metric tons)	Fossil fuel resource 1 (metric tons)	Fossil fuel resource 2 (metric tons)	Fossil fuel resource 3 (metric tons)	Fossil fuel resource 4 (metric tons)	Fossil fuel resource 5 (metric tons)	Fossil fuel resource 6 (metric tons)
2023	5,887,117	2,351,875	2,097,049	41,539	919,175	509,985	641,895	130,219	1,292,430
2024	5,308,316	1,802,933	1,865,467	137,208	879,158	490,395	635,821	175,051	1,187,749
2025	5,049,607	1,705,195	1,790,077	142,367	837,292	463,866	563,301	176,532	1,161,054
2026	4,363,686	1,366,816	2,265,765	167,981	721,455	393,273	519,881	156,078	1,038,201
2027	3,677,764	1,091,731	2,920,645	222,701	579,927	317,101	480,068	167,172	819,064
2028	2,991,843	811,290	3,817,679	360,534	435,432	240,102	385,570	187,487	571,428
2029	2,305,921	629,845	4,198,793	276,854	338,557	187,835	295,418	144,426	432,985
2030	1,620,000	550,194	2,882,753	231,882	295,412	164,415	256,135	121,962	-
2031	1,296,000	441,446	3,045,839	189,906	233,147	129,566	204,917	97,019	-
2032	972,000	346,304	2,994,013	140,644	169,591	95,446	149,334	70,681	-
2033	648,000	234,703	3,081,286	90,757	114,821	62,303	97,814	47,602	-
2034	324,000	120,626	3,108,955	45,635	55,193	31,138	48,043	23,365	-
2035	-	-	3,221,129	-	-	-	-	-	-
2036	-	-	2,994,410	-	-	-	-	-	-
2037	-	-	2,951,594	-	-	-	-	-	-
2038	-	-	2,752,941	-	-	-	-	-	-
2039	-	-	2,654,609	-	-	-	-	-	-
2040	-	-	2,475,750	-	-	-	-	-	-
2041	-	-	2,459,879	-	-	-	-	-	-
2042	-	-	2,209,453	-	-	-	-	-	-
2043	-	-	2,300,472	-	-	-	-	-	-

5	Portfolio5	2-yr forward shift in targets		PGE owned GHG emitting generation (retail)					
	Included in retail total	*Not included in retail total*		Beaver	Carty	Coyote	PW1	PW2	Colstrip
Year	Total Retail GHG Emissions (metric tons)	Market Purchases (metric tons)	Market sales (metric tons)	Fossil fuel resource 1 (metric tons)	Fossil fuel resource 2 (metric tons)	Fossil fuel resource 3 (metric tons)	Fossil fuel resource 4 (metric tons)	Fossil fuel resource 5 (metric tons)	Fossil fuel resource 6 (metric tons)
2023	5,887,117	2,351,875	2,097,049	41,539	919,175	509,985	641,895	130,219	1,292,430
2024	5,308,316	1,802,933	1,865,467	137,208	879,158	490,395	635,821	175,051	1,187,749
2025	5,049,607	1,705,195	1,790,077	142,367	837,292	463,866	563,301	176,532	1,161,054
2026	3,906,405	1,223,584	2,533,044	150,378	645,852	352,061	465,402	139,723	929,406
2027	2,763,202	820,246	3,475,074	167,321	435,715	238,247	360,688	125,601	615,384
2028	1,620,000	439,291	4,696,053	195,219	235,774	130,009	208,775	101,519	309,412
2029	1,458,000	398,241	4,739,485	175,051	214,065	118,765	186,789	91,319	273,770
2030	1,296,000	440,155	3,060,783	185,505	236,329	131,532	204,908	97,570	-
2031	1,134,000	386,265	3,134,640	166,168	204,003	113,370	179,302	84,892	-
2032	972,000	346,304	2,994,013	140,644	169,591	95,446	149,334	70,681	-
2033	810,000	293,378	2,997,121	113,446	143,527	77,879	122,267	59,503	-
2034	648,000	241,252	2,944,970	91,271	110,385	62,276	96,086	46,731	-
2035	486,000	182,364	2,988,259	65,928	84,199	46,539	72,170	34,801	-
2036	324,000	127,168	2,850,321	39,201	56,748	31,161	47,761	21,961	-
2037	162,000	64,141	2,885,898	22,166	26,723	14,823	22,872	11,274	-
2038	-	-	2,752,941	-	-	-	-	-	-
2039	-	-	2,654,609	-	-	-	-	-	-
2040	-	-	2,475,750	-	-	-	-	-	-
2041	-	-	2,459,879	-	-	-	-	-	-
2042	-	-	2,209,453	-	-	-	-	-	-
2043	-	-	2,300,472	-	-	-	-	-	-

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual GHG emissions based on the DEQ methodology over the study period under Reference Case assumptions
For each year, break out the contributions of individual fossil fuel resources, market purchases, and market sales to the total GHG emissions per the DEQ methodology
UM 2225 Order Summary/Rubric references: C.4(a)

PGE note: Forecasts of generation from existing thermal output are based on economic dispatch using prices forecasted in this CEP/IRP. Forecasts of unspecified and other emitting market purchases are a function of historical purchases and a linear decline emission reduction glidepath. Neither reflect operational realities.

6	Portfolio6	Optimize NCE		PGE owned GHG emitting generation (retail)					
		Included in retail total	*Not included in retail total*	Beaver	Carty	Coyote	PW1	PW2	Colstrip
Year	Total Retail GHG Emissions (metric tons)	Market Purchases (metric tons)	Market sales (metric tons)	Fossil fuel resource 1 (metric tons)	Fossil fuel resource 2 (metric tons)	Fossil fuel resource 3 (metric tons)	Fossil fuel resource 4 (metric tons)	Fossil fuel resource 5 (metric tons)	Fossil fuel resource 6 (metric tons)
2023	5,887,117	2,351,875	2,097,049	41,539	919,175	509,985	641,895	130,219	1,292,430
2024	5,308,316	1,802,933	1,865,467	137,208	879,158	490,395	635,821	175,051	1,187,749
2025	5,049,607	1,705,195	1,790,077	142,367	837,292	463,866	563,301	176,532	1,161,054
2026	4,363,686	1,366,816	2,265,765	167,981	721,455	393,273	519,881	156,078	1,038,201
2027	3,677,764	1,091,731	2,920,645	222,701	579,927	317,101	480,068	167,172	819,064
2028	2,991,843	811,290	3,817,679	360,534	435,432	240,102	385,570	187,487	571,428
2029	2,305,921	629,845	4,198,793	276,854	338,557	187,835	295,418	144,426	432,985
2030	1,620,000	550,194	2,882,753	231,882	295,412	164,415	256,135	121,962	-
2031	1,458,000	496,626	2,957,038	213,644	262,290	145,762	230,531	109,147	-
2032	1,296,000	461,739	2,823,141	187,525	226,122	127,262	199,112	94,241	-
2033	1,134,000	410,730	2,828,792	158,824	200,937	109,031	171,174	83,304	-
2034	972,000	361,878	2,780,984	136,906	165,578	93,414	144,128	70,096	-
2035	810,000	303,939	2,825,533	109,880	140,332	77,564	120,283	58,001	-
2036	648,000	254,336	2,695,013	78,402	113,496	62,321	95,522	43,923	-
2037	486,000	192,423	2,732,068	66,499	80,170	44,470	68,615	33,822	-
2038	324,000	133,719	2,617,541	40,467	52,898	29,551	46,191	21,175	-
2039	162,000	68,292	2,594,418	18,400	26,833	14,838	23,117	10,520	-
2040	-	-	2,475,750	-	-	-	-	-	-
2041	-	-	2,459,879	-	-	-	-	-	-
2042	-	-	2,209,453	-	-	-	-	-	-
2043	-	-	2,300,472	-	-	-	-	-	-

7	Portfolio7	Zero NCE		PGE owned GHG emitting generation (retail)					
		Included in retail total	*Not included in retail total*	Beaver	Carty	Coyote	PW1	PW2	Colstrip
Year	Total Retail GHG Emissions (metric tons)	Market Purchases (metric tons)	Market sales (metric tons)	Fossil fuel resource 1 (metric tons)	Fossil fuel resource 2 (metric tons)	Fossil fuel resource 3 (metric tons)	Fossil fuel resource 4 (metric tons)	Fossil fuel resource 5 (metric tons)	Fossil fuel resource 6 (metric tons)
2023	5,887,117	2,351,875	2,097,049	41,539	919,175	509,985	641,895	130,219	1,292,430
2024	5,308,316	1,802,933	1,865,467	137,208	879,158	490,395	635,821	175,051	1,187,749
2025	5,049,607	1,705,195	1,790,077	142,367	837,292	463,866	563,301	176,532	1,161,054
2026	4,363,686	1,366,816	2,265,765	167,981	721,455	393,273	519,881	156,078	1,038,201
2027	3,677,764	1,091,731	2,920,645	222,701	579,927	317,101	480,068	167,172	819,064
2028	2,991,843	811,290	3,817,679	360,534	435,432	240,102	385,570	187,487	571,428
2029	2,305,921	629,845	4,198,793	276,854	338,557	187,835	295,418	144,426	432,985
2030	1,620,000	550,194	2,882,753	231,882	295,412	164,415	256,135	121,962	-
2031	1,458,000	496,626	2,957,038	213,644	262,290	145,762	230,531	109,147	-
2032	1,296,000	461,739	2,823,141	187,525	226,122	127,262	199,112	94,241	-
2033	1,134,000	410,730	2,828,792	158,824	200,937	109,031	171,174	83,304	-
2034	972,000	361,878	2,780,984	136,906	165,578	93,414	144,128	70,096	-
2035	810,000	303,939	2,825,533	109,880	140,332	77,564	120,283	58,001	-
2036	648,000	254,336	2,695,013	78,402	113,496	62,321	95,522	43,923	-
2037	486,000	192,423	2,732,068	66,499	80,170	44,470	68,615	33,822	-
2038	324,000	133,719	2,617,541	40,467	52,898	29,551	46,191	21,175	-
2039	162,000	68,292	2,594,418	18,400	26,833	14,838	23,117	10,520	-
2040	-	-	2,475,750	-	-	-	-	-	-
2041	-	-	2,459,879	-	-	-	-	-	-
2042	-	-	2,209,453	-	-	-	-	-	-
2043	-	-	2,300,472	-	-	-	-	-	-

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual GHG emissions based on the DEQ methodology over the study period under Reference Case assumptions
For each year, break out the contributions of individual fossil fuel resources, market purchases, and market sales to the total GHG emissions per the DEQ methodology
UM 2225 Order Summary/Rubric references: C.4(a)

PGE note: Forecasts of generation from existing thermal output are based on economic dispatch using prices forecasted in this CEP/IRP. Forecasts of unspecified and other emitting market purchases are a function of historical purchases and a linear decline emission reduction glidepath. Neither reflect operational realities.

8	Portfolio8	60 MWa EE		PGE owned GHG emitting generation (retail)					
		Included in retail total	*Not included in retail total*	Beaver	Carty	Coyote	PW1	PW2	Colstrip
Year	Total Retail GHG Emissions (metric tons)	Market Purchases (metric tons)	Market sales (metric tons)	Fossil fuel resource 1 (metric tons)	Fossil fuel resource 2 (metric tons)	Fossil fuel resource 3 (metric tons)	Fossil fuel resource 4 (metric tons)	Fossil fuel resource 5 (metric tons)	Fossil fuel resource 6 (metric tons)
2023	5,887,117	2,351,875	2,097,049	41,539	919,175	509,985	641,895	130,219	1,292,430
2024	5,308,316	1,802,933	1,865,467	137,208	879,158	490,395	635,821	175,051	1,187,749
2025	5,049,607	1,705,195	1,790,077	142,367	837,292	463,866	563,301	176,532	1,161,054
2026	4,363,686	1,366,816	2,265,765	167,981	721,455	393,273	519,881	156,078	1,038,201
2027	3,677,764	1,091,731	2,920,645	222,701	579,927	317,101	480,068	167,172	819,064
2028	2,991,843	811,290	3,817,679	360,534	435,432	240,102	385,570	187,487	571,428
2029	2,305,921	629,845	4,198,793	276,854	338,557	187,835	295,418	144,426	432,985
2030	1,620,000	550,194	2,882,753	231,882	295,412	164,415	256,135	121,962	-
2031	1,458,000	496,626	2,957,038	213,644	262,290	145,762	230,531	109,147	-
2032	1,296,000	461,739	2,823,141	187,525	226,122	127,262	199,112	94,241	-
2033	1,134,000	410,730	2,828,792	158,824	200,937	109,031	171,174	83,304	-
2034	972,000	361,878	2,780,984	136,906	165,578	93,414	144,128	70,096	-
2035	810,000	303,939	2,825,533	109,880	140,332	77,564	120,283	58,001	-
2036	648,000	254,336	2,695,013	78,402	113,496	62,321	95,522	43,923	-
2037	486,000	192,423	2,732,068	66,499	80,170	44,470	68,615	33,822	-
2038	324,000	133,719	2,617,541	40,467	52,898	29,551	46,191	21,175	-
2039	162,000	68,292	2,594,418	18,400	26,833	14,838	23,117	10,520	-
2040	-	-	2,475,750	-	-	-	-	-	-
2041	-	-	2,459,879	-	-	-	-	-	-
2042	-	-	2,209,453	-	-	-	-	-	-
2043	-	-	2,300,472	-	-	-	-	-	-

9	Portfolio9	Default CBREs		PGE owned GHG emitting generation (retail)					
		Included in retail total	*Not included in retail total*	Beaver	Carty	Coyote	PW1	PW2	Colstrip
Year	Total Retail GHG Emissions (metric tons)	Market Purchases (metric tons)	Market sales (metric tons)	Fossil fuel resource 1 (metric tons)	Fossil fuel resource 2 (metric tons)	Fossil fuel resource 3 (metric tons)	Fossil fuel resource 4 (metric tons)	Fossil fuel resource 5 (metric tons)	Fossil fuel resource 6 (metric tons)
2023	5,887,117	2,351,875	2,097,049	41,539	919,175	509,985	641,895	130,219	1,292,430
2024	5,308,316	1,802,933	1,865,467	137,208	879,158	490,395	635,821	175,051	1,187,749
2025	5,049,607	1,705,195	1,790,077	142,367	837,292	463,866	563,301	176,532	1,161,054
2026	4,363,686	1,366,816	2,265,765	167,981	721,455	393,273	519,881	156,078	1,038,201
2027	3,677,764	1,091,731	2,920,645	222,701	579,927	317,101	480,068	167,172	819,064
2028	2,991,843	811,290	3,817,679	360,534	435,432	240,102	385,570	187,487	571,428
2029	2,305,921	629,845	4,198,793	276,854	338,557	187,835	295,418	144,426	432,985
2030	1,620,000	550,194	2,882,753	231,882	295,412	164,415	256,135	121,962	-
2031	1,458,000	496,626	2,957,038	213,644	262,290	145,762	230,531	109,147	-
2032	1,296,000	461,739	2,823,141	187,525	226,122	127,262	199,112	94,241	-
2033	1,134,000	410,730	2,828,792	158,824	200,937	109,031	171,174	83,304	-
2034	972,000	361,878	2,780,984	136,906	165,578	93,414	144,128	70,096	-
2035	810,000	303,939	2,825,533	109,880	140,332	77,564	120,283	58,001	-
2036	648,000	254,336	2,695,013	78,402	113,496	62,321	95,522	43,923	-
2037	486,000	192,423	2,732,068	66,499	80,170	44,470	68,615	33,822	-
2038	324,000	133,719	2,617,541	40,467	52,898	29,551	46,191	21,175	-
2039	162,000	68,292	2,594,418	18,400	26,833	14,838	23,117	10,520	-
2040	-	-	2,475,750	-	-	-	-	-	-
2041	-	-	2,459,879	-	-	-	-	-	-
2042	-	-	2,209,453	-	-	-	-	-	-
2043	-	-	2,300,472	-	-	-	-	-	-

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual GHG emissions based on the DEQ methodology over the study period under Reference Case assumptions
For each year, break out the contributions of individual fossil fuel resources, market purchases, and market sales to the total GHG emissions per the DEQ methodology
UM 2225 Order Summary/Rubric references: C.4(a)

PGE note: Forecasts of generation from existing thermal output are based on economic dispatch using prices forecasted in this CEP/IRP. Forecasts of unspecified and other emitting market purchases are a function of historical purchases and a linear decline emission reduction glidepath. Neither reflect operational realities.

10	Portfolio10	CBRE - 75%		PGE owned GHG emitting generation (retail)					
		Included in retail total	*Not included in retail total*	Beaver	Carty	Coyote	PW1	PW2	Colstrip
Year	Total Retail GHG Emissions (metric tons)	Market Purchases (metric tons)	Market sales (metric tons)	Fossil fuel resource 1 (metric tons)	Fossil fuel resource 2 (metric tons)	Fossil fuel resource 3 (metric tons)	Fossil fuel resource 4 (metric tons)	Fossil fuel resource 5 (metric tons)	Fossil fuel resource 6 (metric tons)
2023	5,887,117	2,351,875	2,097,049	41,539	919,175	509,985	641,895	130,219	1,292,430
2024	5,308,316	1,802,933	1,865,467	137,208	879,158	490,395	635,821	175,051	1,187,749
2025	5,049,607	1,705,195	1,790,077	142,367	837,292	463,866	563,301	176,532	1,161,054
2026	4,363,686	1,366,816	2,265,765	167,981	721,455	393,273	519,881	156,078	1,038,201
2027	3,677,764	1,091,731	2,920,645	222,701	579,927	317,101	480,068	167,172	819,064
2028	2,991,843	811,290	3,817,679	360,534	435,432	240,102	385,570	187,487	571,428
2029	2,305,921	629,845	4,198,793	276,854	338,557	187,835	295,418	144,426	432,985
2030	1,620,000	550,194	2,882,753	231,882	295,412	164,415	256,135	121,962	-
2031	1,458,000	496,626	2,957,038	213,644	262,290	145,762	230,531	109,147	-
2032	1,296,000	461,739	2,823,141	187,525	226,122	127,262	199,112	94,241	-
2033	1,134,000	410,730	2,828,792	158,824	200,937	109,031	171,174	83,304	-
2034	972,000	361,878	2,780,984	136,906	165,578	93,414	144,128	70,096	-
2035	810,000	303,939	2,825,533	109,880	140,332	77,564	120,283	58,001	-
2036	648,000	254,336	2,695,013	78,402	113,496	62,321	95,522	43,923	-
2037	486,000	192,423	2,732,068	66,499	80,170	44,470	68,615	33,822	-
2038	324,000	133,719	2,617,541	40,467	52,898	29,551	46,191	21,175	-
2039	162,000	68,292	2,594,418	18,400	26,833	14,838	23,117	10,520	-
2040	-	-	2,475,750	-	-	-	-	-	-
2041	-	-	2,459,879	-	-	-	-	-	-
2042	-	-	2,209,453	-	-	-	-	-	-
2043	-	-	2,300,472	-	-	-	-	-	-

11	Portfolio11	CBRE - zero		PGE owned GHG emitting generation (retail)					
		Included in retail total	*Not included in retail total*	Beaver	Carty	Coyote	PW1	PW2	Colstrip
Year	Total Retail GHG Emissions (metric tons)	Market Purchases (metric tons)	Market sales (metric tons)	Fossil fuel resource 1 (metric tons)	Fossil fuel resource 2 (metric tons)	Fossil fuel resource 3 (metric tons)	Fossil fuel resource 4 (metric tons)	Fossil fuel resource 5 (metric tons)	Fossil fuel resource 6 (metric tons)
2023	5,887,117	2,351,875	2,097,049	41,539	919,175	509,985	641,895	130,219	1,292,430
2024	5,308,316	1,802,933	1,865,467	137,208	879,158	490,395	635,821	175,051	1,187,749
2025	5,049,607	1,705,195	1,790,077	142,367	837,292	463,866	563,301	176,532	1,161,054
2026	4,363,686	1,366,816	2,265,765	167,981	721,455	393,273	519,881	156,078	1,038,201
2027	3,677,764	1,091,731	2,920,645	222,701	579,927	317,101	480,068	167,172	819,064
2028	2,991,843	811,290	3,817,679	360,534	435,432	240,102	385,570	187,487	571,428
2029	2,305,921	629,845	4,198,793	276,854	338,557	187,835	295,418	144,426	432,985
2030	1,620,000	550,194	2,882,753	231,882	295,412	164,415	256,135	121,962	-
2031	1,458,000	496,626	2,957,038	213,644	262,290	145,762	230,531	109,147	-
2032	1,296,000	461,739	2,823,141	187,525	226,122	127,262	199,112	94,241	-
2033	1,134,000	410,730	2,828,792	158,824	200,937	109,031	171,174	83,304	-
2034	972,000	361,878	2,780,984	136,906	165,578	93,414	144,128	70,096	-
2035	810,000	303,939	2,825,533	109,880	140,332	77,564	120,283	58,001	-
2036	648,000	254,336	2,695,013	78,402	113,496	62,321	95,522	43,923	-
2037	486,000	192,423	2,732,068	66,499	80,170	44,470	68,615	33,822	-
2038	324,000	133,719	2,617,541	40,467	52,898	29,551	46,191	21,175	-
2039	162,000	68,292	2,594,418	18,400	26,833	14,838	23,117	10,520	-
2040	-	-	2,475,750	-	-	-	-	-	-
2041	-	-	2,459,879	-	-	-	-	-	-
2042	-	-	2,209,453	-	-	-	-	-	-
2043	-	-	2,300,472	-	-	-	-	-	-

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual GHG emissions based on the DEQ methodology over the study period under Reference Case assumptions
For each year, break out the contributions of individual fossil fuel resources, market purchases, and market sales to the total GHG emissions per the DEQ methodology
UM 2225 Order Summary/Rubric references: C.4(a)

PGE note: Forecasts of generation from existing thermal output are based on economic dispatch using prices forecasted in this CEP/IRP. Forecasts of unspecified and other emitting market purchases are a function of historical purchases and a linear decline emission reduction glidepath. Neither reflect operational realities.

12	Portfolio12	CBRE - microgrid			PGE owned GHG emitting generation (retail)					
		Included in retail total	*Not included in retail total*		Beaver	Carty	Coyote	PW1	PW2	Colstrip
Year	Total Retail GHG Emissions (metric tons)	Market Purchases (metric tons)	Market sales (metric tons)		Fossil fuel resource 1 (metric tons)	Fossil fuel resource 2 (metric tons)	Fossil fuel resource 3 (metric tons)	Fossil fuel resource 4 (metric tons)	Fossil fuel resource 5 (metric tons)	Fossil fuel resource 6 (metric tons)
2023	5,887,117	2,351,875	2,097,049		41,539	919,175	509,985	641,895	130,219	1,292,430
2024	5,308,316	1,802,933	1,865,467		137,208	879,158	490,395	635,821	175,051	1,187,749
2025	5,049,607	1,705,195	1,790,077		142,367	837,292	463,866	563,301	176,532	1,161,054
2026	4,363,686	1,366,816	2,265,765		167,981	721,455	393,273	519,881	156,078	1,038,201
2027	3,677,764	1,091,731	2,920,645		222,701	579,927	317,101	480,068	167,172	819,064
2028	2,991,843	811,290	3,817,679		360,534	435,432	240,102	385,570	187,487	571,428
2029	2,305,921	629,845	4,198,793		276,854	338,557	187,835	295,418	144,426	432,985
2030	1,620,000	550,194	2,882,753		231,882	295,412	164,415	256,135	121,962	-
2031	1,458,000	496,626	2,957,038		213,644	262,290	145,762	230,531	109,147	-
2032	1,296,000	461,739	2,823,141		187,525	226,122	127,262	199,112	94,241	-
2033	1,134,000	410,730	2,828,792		158,824	200,937	109,031	171,174	83,304	-
2034	972,000	361,878	2,780,984		136,906	165,578	93,414	144,128	70,096	-
2035	810,000	303,939	2,825,533		109,880	140,332	77,564	120,283	58,001	-
2036	648,000	254,336	2,695,013		78,402	113,496	62,321	95,522	43,923	-
2037	486,000	192,423	2,732,068		66,499	80,170	44,470	68,615	33,822	-
2038	324,000	133,719	2,617,541		40,467	52,898	29,551	46,191	21,175	-
2039	162,000	68,292	2,594,418		18,400	26,833	14,838	23,117	10,520	-
2040	-	-	2,475,750		-	-	-	-	-	-
2041	-	-	2,459,879		-	-	-	-	-	-
2042	-	-	2,209,453		-	-	-	-	-	-
2043	-	-	2,300,472		-	-	-	-	-	-

13	Portfolio13	CBRE - optimize			PGE owned GHG emitting generation (retail)					
		Included in retail total	*Not included in retail total*		Beaver	Carty	Coyote	PW1	PW2	Colstrip
Year	Total Retail GHG Emissions (metric tons)	Market Purchases (metric tons)	Market sales (metric tons)		Fossil fuel resource 1 (metric tons)	Fossil fuel resource 2 (metric tons)	Fossil fuel resource 3 (metric tons)	Fossil fuel resource 4 (metric tons)	Fossil fuel resource 5 (metric tons)	Fossil fuel resource 6 (metric tons)
2023	5,887,117	2,351,875	2,097,049		41,539	919,175	509,985	641,895	130,219	1,292,430
2024	5,308,316	1,802,933	1,865,467		137,208	879,158	490,395	635,821	175,051	1,187,749
2025	5,049,607	1,705,195	1,790,077		142,367	837,292	463,866	563,301	176,532	1,161,054
2026	4,363,686	1,366,816	2,265,765		167,981	721,455	393,273	519,881	156,078	1,038,201
2027	3,677,764	1,091,731	2,920,645		222,701	579,927	317,101	480,068	167,172	819,064
2028	2,991,843	811,290	3,817,679		360,534	435,432	240,102	385,570	187,487	571,428
2029	2,305,921	629,845	4,198,793		276,854	338,557	187,835	295,418	144,426	432,985
2030	1,620,000	550,194	2,882,753		231,882	295,412	164,415	256,135	121,962	-
2031	1,458,000	496,626	2,957,038		213,644	262,290	145,762	230,531	109,147	-
2032	1,296,000	461,739	2,823,141		187,525	226,122	127,262	199,112	94,241	-
2033	1,134,000	410,730	2,828,792		158,824	200,937	109,031	171,174	83,304	-
2034	972,000	361,878	2,780,984		136,906	165,578	93,414	144,128	70,096	-
2035	810,000	303,939	2,825,533		109,880	140,332	77,564	120,283	58,001	-
2036	648,000	254,336	2,695,013		78,402	113,496	62,321	95,522	43,923	-
2037	486,000	192,423	2,732,068		66,499	80,170	44,470	68,615	33,822	-
2038	324,000	133,719	2,617,541		40,467	52,898	29,551	46,191	21,175	-
2039	162,000	68,292	2,594,418		18,400	26,833	14,838	23,117	10,520	-
2040	-	-	2,475,750		-	-	-	-	-	-
2041	-	-	2,459,879		-	-	-	-	-	-
2042	-	-	2,209,453		-	-	-	-	-	-
2043	-	-	2,300,472		-	-	-	-	-	-

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual GHG emissions based on the DEQ methodology over the study period under Reference Case assumptions
For each year, break out the contributions of individual fossil fuel resources, market purchases, and market sales to the total GHG emissions per the DEQ methodology
UM 2225 Order Summary/Rubric references: C.4(a)

PGE note: Forecasts of generation from existing thermal output are based on economic dispatch using prices forecasted in this CEP/IRP. Forecasts of unspecified and other emitting market purchases are a function of historical purchases and a linear decline emission reduction glidepath. Neither reflect operational realities.

14	Portfolio14	Unconstrained Tx			PGE owned GHG emitting generation (retail)					
		Included in retail total	*Not included in retail total*		Beaver	Carty	Coyote	PW1	PW2	Colstrip
Year	Total Retail GHG Emissions (metric tons)	Market Purchases (metric tons)	Market sales (metric tons)		Fossil fuel resource 1 (metric tons)	Fossil fuel resource 2 (metric tons)	Fossil fuel resource 3 (metric tons)	Fossil fuel resource 4 (metric tons)	Fossil fuel resource 5 (metric tons)	Fossil fuel resource 6 (metric tons)
2023	5,887,117	2,351,875	2,097,049		41,539	919,175	509,985	641,895	130,219	1,292,430
2024	5,308,316	1,802,933	1,865,467		137,208	879,158	490,395	635,821	175,051	1,187,749
2025	5,049,607	1,705,195	1,790,077		142,367	837,292	463,866	563,301	176,532	1,161,054
2026	4,363,686	1,366,816	2,265,765		167,981	721,455	393,273	519,881	156,078	1,038,201
2027	3,677,764	1,091,731	2,920,645		222,701	579,927	317,101	480,068	167,172	819,064
2028	2,991,843	811,290	3,817,679		360,534	435,432	240,102	385,570	187,487	571,428
2029	2,305,921	629,845	4,198,793		276,854	338,557	187,835	295,418	144,426	432,985
2030	1,620,000	550,194	2,882,753		231,882	295,412	164,415	256,135	121,962	-
2031	1,458,000	496,626	2,957,038		213,644	262,290	145,762	230,531	109,147	-
2032	1,296,000	461,739	2,823,141		187,525	226,122	127,262	199,112	94,241	-
2033	1,134,000	410,730	2,828,792		158,824	200,937	109,031	171,174	83,304	-
2034	972,000	361,878	2,780,984		136,906	165,578	93,414	144,128	70,096	-
2035	810,000	303,939	2,825,533		109,880	140,332	77,564	120,283	58,001	-
2036	648,000	254,336	2,695,013		78,402	113,496	62,321	95,522	43,923	-
2037	486,000	192,423	2,732,068		66,499	80,170	44,470	68,615	33,822	-
2038	324,000	133,719	2,617,541		40,467	52,898	29,551	46,191	21,175	-
2039	162,000	68,292	2,594,418		18,400	26,833	14,838	23,117	10,520	-
2040	-	-	2,475,750		-	-	-	-	-	-
2041	-	-	2,459,879		-	-	-	-	-	-
2042	-	-	2,209,453		-	-	-	-	-	-
2043	-	-	2,300,472		-	-	-	-	-	-

15	Portfolio15	No Upgrades			PGE owned GHG emitting generation (retail)					
		Included in retail total	*Not included in retail total*		Beaver	Carty	Coyote	PW1	PW2	Colstrip
Year	Total Retail GHG Emissions (metric tons)	Market Purchases (metric tons)	Market sales (metric tons)		Fossil fuel resource 1 (metric tons)	Fossil fuel resource 2 (metric tons)	Fossil fuel resource 3 (metric tons)	Fossil fuel resource 4 (metric tons)	Fossil fuel resource 5 (metric tons)	Fossil fuel resource 6 (metric tons)
2023	5,887,117	2,351,875	2,097,049		41,539	919,175	509,985	641,895	130,219	1,292,430
2024	5,308,316	1,802,933	1,865,467		137,208	879,158	490,395	635,821	175,051	1,187,749
2025	5,049,607	1,705,195	1,790,077		142,367	837,292	463,866	563,301	176,532	1,161,054
2026	4,363,686	1,366,816	2,265,765		167,981	721,455	393,273	519,881	156,078	1,038,201
2027	3,677,764	1,091,731	2,920,645		222,701	579,927	317,101	480,068	167,172	819,064
2028	2,991,843	811,290	3,817,679		360,534	435,432	240,102	385,570	187,487	571,428
2029	2,305,921	629,845	4,198,793		276,854	338,557	187,835	295,418	144,426	432,985
2030	1,620,000	550,194	2,882,753		231,882	295,412	164,415	256,135	121,962	-
2031	1,458,000	496,626	2,957,038		213,644	262,290	145,762	230,531	109,147	-
2032	1,296,000	461,739	2,823,141		187,525	226,122	127,262	199,112	94,241	-
2033	1,134,000	410,730	2,828,792		158,824	200,937	109,031	171,174	83,304	-
2034	972,000	361,878	2,780,984		136,906	165,578	93,414	144,128	70,096	-
2035	810,000	303,939	2,825,533		109,880	140,332	77,564	120,283	58,001	-
2036	648,000	254,336	2,695,013		78,402	113,496	62,321	95,522	43,923	-
2037	486,000	192,423	2,732,068		66,499	80,170	44,470	68,615	33,822	-
2038	324,000	133,719	2,617,541		40,467	52,898	29,551	46,191	21,175	-
2039	162,000	68,292	2,594,418		18,400	26,833	14,838	23,117	10,520	-
2040	-	-	2,475,750		-	-	-	-	-	-
2041	-	-	2,459,879		-	-	-	-	-	-
2042	-	-	2,209,453		-	-	-	-	-	-
2043	-	-	2,300,472		-	-	-	-	-	-

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual GHG emissions based on the DEQ methodology over the study period under Reference Case assumptions
For each year, break out the contributions of individual fossil fuel resources, market purchases, and market sales to the total GHG emissions per the DEQ methodology
UM 2225 Order Summary/Rubric references: C.4(a)

PGE note: Forecasts of generation from existing thermal output are based on economic dispatch using prices forecasted in this CEP/IRP. Forecasts of unspecified and other emitting market purchases are a function of historical purchases and a linear decline emission reduction glidepath. Neither reflect operational realities.

16	Portfolio16	Unconstrained SoA		PGE owned GHG emitting generation (retail)					
	Included in retail total	*Not included in retail total*		Beaver	Carty	Coyote	PW1	PW2	Colstrip
Year	Total Retail GHG Emissions (metric tons)	Market Purchases (metric tons)	Market sales (metric tons)	Fossil fuel resource 1 (metric tons)	Fossil fuel resource 2 (metric tons)	Fossil fuel resource 3 (metric tons)	Fossil fuel resource 4 (metric tons)	Fossil fuel resource 5 (metric tons)	Fossil fuel resource 6 (metric tons)
2023	5,887,117	2,351,875	2,097,049	41,539	919,175	509,985	641,895	130,219	1,292,430
2024	5,308,316	1,802,933	1,865,467	137,208	879,158	490,395	635,821	175,051	1,187,749
2025	5,049,607	1,705,195	1,790,077	142,367	837,292	463,866	563,301	176,532	1,161,054
2026	4,363,686	1,366,816	2,265,765	167,981	721,455	393,273	519,881	156,078	1,038,201
2027	3,677,764	1,091,731	2,920,645	222,701	579,927	317,101	480,068	167,172	819,064
2028	2,991,843	811,290	3,817,679	360,534	435,432	240,102	385,570	187,487	571,428
2029	2,305,921	629,845	4,198,793	276,854	338,557	187,835	295,418	144,426	432,985
2030	1,620,000	550,194	2,882,753	231,882	295,412	164,415	256,135	121,962	-
2031	1,458,000	496,626	2,957,038	213,644	262,290	145,762	230,531	109,147	-
2032	1,296,000	461,739	2,823,141	187,525	226,122	127,262	199,112	94,241	-
2033	1,134,000	410,730	2,828,792	158,824	200,937	109,031	171,174	83,304	-
2034	972,000	361,878	2,780,984	136,906	165,578	93,414	144,128	70,096	-
2035	810,000	303,939	2,825,533	109,880	140,332	77,564	120,283	58,001	-
2036	648,000	254,336	2,695,013	78,402	113,496	62,321	95,522	43,923	-
2037	486,000	192,423	2,732,068	66,499	80,170	44,470	68,615	33,822	-
2038	324,000	133,719	2,617,541	40,467	52,898	29,551	46,191	21,175	-
2039	162,000	68,292	2,594,418	18,400	26,833	14,838	23,117	10,520	-
2040	-	-	2,475,750	-	-	-	-	-	-
2041	-	-	2,459,879	-	-	-	-	-	-
2042	-	-	2,209,453	-	-	-	-	-	-
2043	-	-	2,300,472	-	-	-	-	-	-

17	Portfolio17	Unconstrained SoA Plus		PGE owned GHG emitting generation (retail)					
	Included in retail total	*Not included in retail total*		Beaver	Carty	Coyote	PW1	PW2	Colstrip
Year	Total Retail GHG Emissions (metric tons)	Market Purchases (metric tons)	Market sales (metric tons)	Fossil fuel resource 1 (metric tons)	Fossil fuel resource 2 (metric tons)	Fossil fuel resource 3 (metric tons)	Fossil fuel resource 4 (metric tons)	Fossil fuel resource 5 (metric tons)	Fossil fuel resource 6 (metric tons)
2023	5,887,117	2,351,875	2,097,049	41,539	919,175	509,985	641,895	130,219	1,292,430
2024	5,308,316	1,802,933	1,865,467	137,208	879,158	490,395	635,821	175,051	1,187,749
2025	5,049,607	1,705,195	1,790,077	142,367	837,292	463,866	563,301	176,532	1,161,054
2026	4,363,686	1,366,816	2,265,765	167,981	721,455	393,273	519,881	156,078	1,038,201
2027	3,677,764	1,091,731	2,920,645	222,701	579,927	317,101	480,068	167,172	819,064
2028	2,991,843	811,290	3,817,679	360,534	435,432	240,102	385,570	187,487	571,428
2029	2,305,921	629,845	4,198,793	276,854	338,557	187,835	295,418	144,426	432,985
2030	1,620,000	550,194	2,882,753	231,882	295,412	164,415	256,135	121,962	-
2031	1,458,000	496,626	2,957,038	213,644	262,290	145,762	230,531	109,147	-
2032	1,296,000	461,739	2,823,141	187,525	226,122	127,262	199,112	94,241	-
2033	1,134,000	410,730	2,828,792	158,824	200,937	109,031	171,174	83,304	-
2034	972,000	361,878	2,780,984	136,906	165,578	93,414	144,128	70,096	-
2035	810,000	303,939	2,825,533	109,880	140,332	77,564	120,283	58,001	-
2036	648,000	254,336	2,695,013	78,402	113,496	62,321	95,522	43,923	-
2037	486,000	192,423	2,732,068	66,499	80,170	44,470	68,615	33,822	-
2038	324,000	133,719	2,617,541	40,467	52,898	29,551	46,191	21,175	-
2039	162,000	68,292	2,594,418	18,400	26,833	14,838	23,117	10,520	-
2040	-	-	2,475,750	-	-	-	-	-	-
2041	-	-	2,459,879	-	-	-	-	-	-
2042	-	-	2,209,453	-	-	-	-	-	-
2043	-	-	2,300,472	-	-	-	-	-	-

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual GHG emissions based on the DEQ methodology over the study period under Reference Case assumptions
For each year, break out the contributions of individual fossil fuel resources, market purchases, and market sales to the total GHG emissions per the DEQ methodology
UM 2225 Order Summary/Rubric references: C.4(a)

PGE note: Forecasts of generation from existing thermal output are based on economic dispatch using prices forecasted in this CEP/IRP. Forecasts of unspecified and other emitting market purchases are a function of historical purchases and a linear decline emission reduction glidepath. Neither reflect operational realities.

18	Portfolio18	SoA in 2027		PGE owned GHG emitting generation (retail)					
		Included in retail total	*Not included in retail total*	Beaver	Carty	Coyote	PW1	PW2	Colstrip
Year	Total Retail GHG Emissions (metric tons)	Market Purchases (metric tons)	Market sales (metric tons)	Fossil fuel resource 1 (metric tons)	Fossil fuel resource 2 (metric tons)	Fossil fuel resource 3 (metric tons)	Fossil fuel resource 4 (metric tons)	Fossil fuel resource 5 (metric tons)	Fossil fuel resource 6 (metric tons)
2023	5,887,117	2,351,875	2,097,049	41,539	919,175	509,985	641,895	130,219	1,292,430
2024	5,308,316	1,802,933	1,865,467	137,208	879,158	490,395	635,821	175,051	1,187,749
2025	5,049,607	1,705,195	1,790,077	142,367	837,292	463,866	563,301	176,532	1,161,054
2026	4,363,686	1,366,816	2,265,765	167,981	721,455	393,273	519,881	156,078	1,038,201
2027	3,677,764	1,091,731	2,920,645	222,701	579,927	317,101	480,068	167,172	819,064
2028	2,991,843	811,290	3,817,679	360,534	435,432	240,102	385,570	187,487	571,428
2029	2,305,921	629,845	4,198,793	276,854	338,557	187,835	295,418	144,426	432,985
2030	1,620,000	550,194	2,882,753	231,882	295,412	164,415	256,135	121,962	-
2031	1,458,000	496,626	2,957,038	213,644	262,290	145,762	230,531	109,147	-
2032	1,296,000	461,739	2,823,141	187,525	226,122	127,262	199,112	94,241	-
2033	1,134,000	410,730	2,828,792	158,824	200,937	109,031	171,174	83,304	-
2034	972,000	361,878	2,780,984	136,906	165,578	93,414	144,128	70,096	-
2035	810,000	303,939	2,825,533	109,880	140,332	77,564	120,283	58,001	-
2036	648,000	254,336	2,695,013	78,402	113,496	62,321	95,522	43,923	-
2037	486,000	192,423	2,732,068	66,499	80,170	44,470	68,615	33,822	-
2038	324,000	133,719	2,617,541	40,467	52,898	29,551	46,191	21,175	-
2039	162,000	68,292	2,594,418	18,400	26,833	14,838	23,117	10,520	-
2040	-	-	2,475,750	-	-	-	-	-	-
2041	-	-	2,459,879	-	-	-	-	-	-
2042	-	-	2,209,453	-	-	-	-	-	-
2043	-	-	2,300,472	-	-	-	-	-	-

19	Portfolio19	SoA in 2029		PGE owned GHG emitting generation (retail)					
		Included in retail total	*Not included in retail total*	Beaver	Carty	Coyote	PW1	PW2	Colstrip
Year	Total Retail GHG Emissions (metric tons)	Market Purchases (metric tons)	Market sales (metric tons)	Fossil fuel resource 1 (metric tons)	Fossil fuel resource 2 (metric tons)	Fossil fuel resource 3 (metric tons)	Fossil fuel resource 4 (metric tons)	Fossil fuel resource 5 (metric tons)	Fossil fuel resource 6 (metric tons)
2023	5,887,117	2,351,875	2,097,049	41,539	919,175	509,985	641,895	130,219	1,292,430
2024	5,308,316	1,802,933	1,865,467	137,208	879,158	490,395	635,821	175,051	1,187,749
2025	5,049,607	1,705,195	1,790,077	142,367	837,292	463,866	563,301	176,532	1,161,054
2026	4,363,686	1,366,816	2,265,765	167,981	721,455	393,273	519,881	156,078	1,038,201
2027	3,677,764	1,091,731	2,920,645	222,701	579,927	317,101	480,068	167,172	819,064
2028	2,991,843	811,290	3,817,679	360,534	435,432	240,102	385,570	187,487	571,428
2029	2,305,921	629,845	4,198,793	276,854	338,557	187,835	295,418	144,426	432,985
2030	1,620,000	550,194	2,882,753	231,882	295,412	164,415	256,135	121,962	-
2031	1,458,000	496,626	2,957,038	213,644	262,290	145,762	230,531	109,147	-
2032	1,296,000	461,739	2,823,141	187,525	226,122	127,262	199,112	94,241	-
2033	1,134,000	410,730	2,828,792	158,824	200,937	109,031	171,174	83,304	-
2034	972,000	361,878	2,780,984	136,906	165,578	93,414	144,128	70,096	-
2035	810,000	303,939	2,825,533	109,880	140,332	77,564	120,283	58,001	-
2036	648,000	254,336	2,695,013	78,402	113,496	62,321	95,522	43,923	-
2037	486,000	192,423	2,732,068	66,499	80,170	44,470	68,615	33,822	-
2038	324,000	133,719	2,617,541	40,467	52,898	29,551	46,191	21,175	-
2039	162,000	68,292	2,594,418	18,400	26,833	14,838	23,117	10,520	-
2040	-	-	2,475,750	-	-	-	-	-	-
2041	-	-	2,459,879	-	-	-	-	-	-
2042	-	-	2,209,453	-	-	-	-	-	-
2043	-	-	2,300,472	-	-	-	-	-	-

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual GHG emissions based on the DEQ methodology over the study period under Reference Case assumptions
For each year, break out the contributions of individual fossil fuel resources, market purchases, and market sales to the total GHG emissions per the DEQ methodology
UM 2225 Order Summary/Rubric references: C.4(a)

PGE note: Forecasts of generation from existing thermal output are based on economic dispatch using prices forecasted in this CEP/IRP. Forecasts of unspecified and other emitting market purchases are a function of historical purchases and a linear decline emission reduction glidepath. Neither reflect operational realities.

20	Portfolio20	WY in 2026		PGE owned GHG emitting generation (retail)					
		Included in retail total	*Not included in retail total*	Beaver	Carty	Coyote	PW1	PW2	Colstrip
Year	Total Retail GHG Emissions (metric tons)	Market Purchases (metric tons)	Market sales (metric tons)	Fossil fuel resource 1 (metric tons)	Fossil fuel resource 2 (metric tons)	Fossil fuel resource 3 (metric tons)	Fossil fuel resource 4 (metric tons)	Fossil fuel resource 5 (metric tons)	Fossil fuel resource 6 (metric tons)
2023	5,887,117	2,351,875	2,097,049	41,539	919,175	509,985	641,895	130,219	1,292,430
2024	5,308,316	1,802,933	1,865,467	137,208	879,158	490,395	635,821	175,051	1,187,749
2025	5,049,607	1,705,195	1,790,077	142,367	837,292	463,866	563,301	176,532	1,161,054
2026	4,363,686	1,366,816	2,265,765	167,981	721,455	393,273	519,881	156,078	1,038,201
2027	3,677,764	1,091,731	2,920,645	222,701	579,927	317,101	480,068	167,172	819,064
2028	2,991,843	811,290	3,817,679	360,534	435,432	240,102	385,570	187,487	571,428
2029	2,305,921	629,845	4,198,793	276,854	338,557	187,835	295,418	144,426	432,985
2030	1,620,000	550,194	2,882,753	231,882	295,412	164,415	256,135	121,962	-
2031	1,458,000	496,626	2,957,038	213,644	262,290	145,762	230,531	109,147	-
2032	1,296,000	461,739	2,823,141	187,525	226,122	127,262	199,112	94,241	-
2033	1,134,000	410,730	2,828,792	158,824	200,937	109,031	171,174	83,304	-
2034	972,000	361,878	2,780,984	136,906	165,578	93,414	144,128	70,096	-
2035	810,000	303,939	2,825,533	109,880	140,332	77,564	120,283	58,001	-
2036	648,000	254,336	2,695,013	78,402	113,496	62,321	95,522	43,923	-
2037	486,000	192,423	2,732,068	66,499	80,170	44,470	68,615	33,822	-
2038	324,000	133,719	2,617,541	40,467	52,898	29,551	46,191	21,175	-
2039	162,000	68,292	2,594,418	18,400	26,833	14,838	23,117	10,520	-
2040	-	-	2,475,750	-	-	-	-	-	-
2041	-	-	2,459,879	-	-	-	-	-	-
2042	-	-	2,209,453	-	-	-	-	-	-
2043	-	-	2,300,472	-	-	-	-	-	-

21	Portfolio21	NV in 2026		PGE owned GHG emitting generation (retail)					
		Included in retail total	*Not included in retail total*	Beaver	Carty	Coyote	PW1	PW2	Colstrip
Year	Total Retail GHG Emissions (metric tons)	Market Purchases (metric tons)	Market sales (metric tons)	Fossil fuel resource 1 (metric tons)	Fossil fuel resource 2 (metric tons)	Fossil fuel resource 3 (metric tons)	Fossil fuel resource 4 (metric tons)	Fossil fuel resource 5 (metric tons)	Fossil fuel resource 6 (metric tons)
2023	5,887,117	2,351,875	2,097,049	41,539	919,175	509,985	641,895	130,219	1,292,430
2024	5,308,316	1,802,933	1,865,467	137,208	879,158	490,395	635,821	175,051	1,187,749
2025	5,049,607	1,705,195	1,790,077	142,367	837,292	463,866	563,301	176,532	1,161,054
2026	4,363,686	1,366,816	2,265,765	167,981	721,455	393,273	519,881	156,078	1,038,201
2027	3,677,764	1,091,731	2,920,645	222,701	579,927	317,101	480,068	167,172	819,064
2028	2,991,843	811,290	3,817,679	360,534	435,432	240,102	385,570	187,487	571,428
2029	2,305,921	629,845	4,198,793	276,854	338,557	187,835	295,418	144,426	432,985
2030	1,620,000	550,194	2,882,753	231,882	295,412	164,415	256,135	121,962	-
2031	1,458,000	496,626	2,957,038	213,644	262,290	145,762	230,531	109,147	-
2032	1,296,000	461,739	2,823,141	187,525	226,122	127,262	199,112	94,241	-
2033	1,134,000	410,730	2,828,792	158,824	200,937	109,031	171,174	83,304	-
2034	972,000	361,878	2,780,984	136,906	165,578	93,414	144,128	70,096	-
2035	810,000	303,939	2,825,533	109,880	140,332	77,564	120,283	58,001	-
2036	648,000	254,336	2,695,013	78,402	113,496	62,321	95,522	43,923	-
2037	486,000	192,423	2,732,068	66,499	80,170	44,470	68,615	33,822	-
2038	324,000	133,719	2,617,541	40,467	52,898	29,551	46,191	21,175	-
2039	162,000	68,292	2,594,418	18,400	26,833	14,838	23,117	10,520	-
2040	-	-	2,475,750	-	-	-	-	-	-
2041	-	-	2,459,879	-	-	-	-	-	-
2042	-	-	2,209,453	-	-	-	-	-	-
2043	-	-	2,300,472	-	-	-	-	-	-

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual GHG emissions based on the DEQ methodology over the study period under Reference Case assumptions
For each year, break out the contributions of individual fossil fuel resources, market purchases, and market sales to the total GHG emissions per the DEQ methodology
UM 2225 Order Summary/Rubric references: C.4(a)

PGE note: Forecasts of generation from existing thermal output are based on economic dispatch using prices forecasted in this CEP/IRP. Forecasts of unspecified and other emitting market purchases are a function of historical purchases and a linear decline emission reduction glidepath. Neither reflect operational realities.

22	Portfolio22	WY in 2028		PGE owned GHG emitting generation (retail)					
		Included in retail total	*Not included in retail total*	Beaver	Carty	Coyote	PW1	PW2	Colstrip
Year	Total Retail GHG Emissions (metric tons)	Market Purchases (metric tons)	Market sales (metric tons)	Fossil fuel resource 1 (metric tons)	Fossil fuel resource 2 (metric tons)	Fossil fuel resource 3 (metric tons)	Fossil fuel resource 4 (metric tons)	Fossil fuel resource 5 (metric tons)	Fossil fuel resource 6 (metric tons)
2023	5,887,117	2,351,875	2,097,049	41,539	919,175	509,985	641,895	130,219	1,292,430
2024	5,308,316	1,802,933	1,865,467	137,208	879,158	490,395	635,821	175,051	1,187,749
2025	5,049,607	1,705,195	1,790,077	142,367	837,292	463,866	563,301	176,532	1,161,054
2026	4,363,686	1,366,816	2,265,765	167,981	721,455	393,273	519,881	156,078	1,038,201
2027	3,677,764	1,091,731	2,920,645	222,701	579,927	317,101	480,068	167,172	819,064
2028	2,991,843	811,290	3,817,679	360,534	435,432	240,102	385,570	187,487	571,428
2029	2,305,921	629,845	4,198,793	276,854	338,557	187,835	295,418	144,426	432,985
2030	1,620,000	550,194	2,882,753	231,882	295,412	164,415	256,135	121,962	-
2031	1,458,000	496,626	2,957,038	213,644	262,290	145,762	230,531	109,147	-
2032	1,296,000	461,739	2,823,141	187,525	226,122	127,262	199,112	94,241	-
2033	1,134,000	410,730	2,828,792	158,824	200,937	109,031	171,174	83,304	-
2034	972,000	361,878	2,780,984	136,906	165,578	93,414	144,128	70,096	-
2035	810,000	303,939	2,825,533	109,880	140,332	77,564	120,283	58,001	-
2036	648,000	254,336	2,695,013	78,402	113,496	62,321	95,522	43,923	-
2037	486,000	192,423	2,732,068	66,499	80,170	44,470	68,615	33,822	-
2038	324,000	133,719	2,617,541	40,467	52,898	29,551	46,191	21,175	-
2039	162,000	68,292	2,594,418	18,400	26,833	14,838	23,117	10,520	-
2040	-	-	2,475,750	-	-	-	-	-	-
2041	-	-	2,459,879	-	-	-	-	-	-
2042	-	-	2,209,453	-	-	-	-	-	-
2043	-	-	2,300,472	-	-	-	-	-	-

23	Portfolio23	NV in 2028		PGE owned GHG emitting generation (retail)					
		Included in retail total	*Not included in retail total*	Beaver	Carty	Coyote	PW1	PW2	Colstrip
Year	Total Retail GHG Emissions (metric tons)	Market Purchases (metric tons)	Market sales (metric tons)	Fossil fuel resource 1 (metric tons)	Fossil fuel resource 2 (metric tons)	Fossil fuel resource 3 (metric tons)	Fossil fuel resource 4 (metric tons)	Fossil fuel resource 5 (metric tons)	Fossil fuel resource 6 (metric tons)
2023	5,887,117	2,351,875	2,097,049	41,539	919,175	509,985	641,895	130,219	1,292,430
2024	5,308,316	1,802,933	1,865,467	137,208	879,158	490,395	635,821	175,051	1,187,749
2025	5,049,607	1,705,195	1,790,077	142,367	837,292	463,866	563,301	176,532	1,161,054
2026	4,363,686	1,366,816	2,265,765	167,981	721,455	393,273	519,881	156,078	1,038,201
2027	3,677,764	1,091,731	2,920,645	222,701	579,927	317,101	480,068	167,172	819,064
2028	2,991,843	811,290	3,817,679	360,534	435,432	240,102	385,570	187,487	571,428
2029	2,305,921	629,845	4,198,793	276,854	338,557	187,835	295,418	144,426	432,985
2030	1,620,000	550,194	2,882,753	231,882	295,412	164,415	256,135	121,962	-
2031	1,458,000	496,626	2,957,038	213,644	262,290	145,762	230,531	109,147	-
2032	1,296,000	461,739	2,823,141	187,525	226,122	127,262	199,112	94,241	-
2033	1,134,000	410,730	2,828,792	158,824	200,937	109,031	171,174	83,304	-
2034	972,000	361,878	2,780,984	136,906	165,578	93,414	144,128	70,096	-
2035	810,000	303,939	2,825,533	109,880	140,332	77,564	120,283	58,001	-
2036	648,000	254,336	2,695,013	78,402	113,496	62,321	95,522	43,923	-
2037	486,000	192,423	2,732,068	66,499	80,170	44,470	68,615	33,822	-
2038	324,000	133,719	2,617,541	40,467	52,898	29,551	46,191	21,175	-
2039	162,000	68,292	2,594,418	18,400	26,833	14,838	23,117	10,520	-
2040	-	-	2,475,750	-	-	-	-	-	-
2041	-	-	2,459,879	-	-	-	-	-	-
2042	-	-	2,209,453	-	-	-	-	-	-
2043	-	-	2,300,472	-	-	-	-	-	-

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual GHG emissions based on the DEQ methodology over the study period under Reference Case assumptions
For each year, break out the contributions of individual fossil fuel resources, market purchases, and market sales to the total GHG emissions per the DEQ methodology
UM 2225 Order Summary/Rubric references: C.4(a)

PGE note: Forecasts of generation from existing thermal output are based on economic dispatch using prices forecasted in this CEP/IRP. Forecasts of unspecified and other emitting market purchases are a function of historical purchases and a linear decline emission reduction glidepath. Neither reflect operational realities.

24	Portfolio24	Oregon-only resources		PGE owned GHG emitting generation (retail)					
		Included in retail total	*Not included in retail total*	Beaver	Carty	Coyote	PW1	PW2	Colstrip
Year	Total Retail GHG Emissions (metric tons)	Market Purchases (metric tons)	Market sales (metric tons)	Fossil fuel resource 1 (metric tons)	Fossil fuel resource 2 (metric tons)	Fossil fuel resource 3 (metric tons)	Fossil fuel resource 4 (metric tons)	Fossil fuel resource 5 (metric tons)	Fossil fuel resource 6 (metric tons)
2023	5,887,117	2,351,875	2,097,049	41,539	919,175	509,985	641,895	130,219	1,292,430
2024	5,308,316	1,802,933	1,865,467	137,208	879,158	490,395	635,821	175,051	1,187,749
2025	5,049,607	1,705,195	1,790,077	142,367	837,292	463,866	563,301	176,532	1,161,054
2026	4,363,686	1,366,816	2,265,765	167,981	721,455	393,273	519,881	156,078	1,038,201
2027	3,677,764	1,091,731	2,920,645	222,701	579,927	317,101	480,068	167,172	819,064
2028	2,991,843	811,290	3,817,679	360,534	435,432	240,102	385,570	187,487	571,428
2029	2,305,921	629,845	4,198,793	276,854	338,557	187,835	295,418	144,426	432,985
2030	1,620,000	550,194	2,882,753	231,882	295,412	164,415	256,135	121,962	-
2031	1,458,000	496,626	2,957,038	213,644	262,290	145,762	230,531	109,147	-
2032	1,296,000	461,739	2,823,141	187,525	226,122	127,262	199,112	94,241	-
2033	1,134,000	410,730	2,828,792	158,824	200,937	109,031	171,174	83,304	-
2034	972,000	361,878	2,780,984	136,906	165,578	93,414	144,128	70,096	-
2035	810,000	303,939	2,825,533	109,880	140,332	77,564	120,283	58,001	-
2036	648,000	254,336	2,695,013	78,402	113,496	62,321	95,522	43,923	-
2037	486,000	192,423	2,732,068	66,499	80,170	44,470	68,615	33,822	-
2038	324,000	133,719	2,617,541	40,467	52,898	29,551	46,191	21,175	-
2039	162,000	68,292	2,594,418	18,400	26,833	14,838	23,117	10,520	-
2040	-	-	2,475,750	-	-	-	-	-	-
2041	-	-	2,459,879	-	-	-	-	-	-
2042	-	-	2,209,453	-	-	-	-	-	-
2043	-	-	2,300,472	-	-	-	-	-	-

25	Portfolio25	Physical RPS		PGE owned GHG emitting generation (retail)					
		Included in retail total	*Not included in retail total*	Beaver	Carty	Coyote	PW1	PW2	Colstrip
Year	Total Retail GHG Emissions (metric tons)	Market Purchases (metric tons)	Market sales (metric tons)	Fossil fuel resource 1 (metric tons)	Fossil fuel resource 2 (metric tons)	Fossil fuel resource 3 (metric tons)	Fossil fuel resource 4 (metric tons)	Fossil fuel resource 5 (metric tons)	Fossil fuel resource 6 (metric tons)
2023	5,887,117	2,351,875	2,097,049	41,539	919,175	509,985	641,895	130,219	1,292,430
2024	5,308,316	1,802,933	1,865,467	137,208	879,158	490,395	635,821	175,051	1,187,749
2025	5,049,607	1,705,195	1,790,077	142,367	837,292	463,866	563,301	176,532	1,161,054
2026	4,363,686	1,366,816	2,265,765	167,981	721,455	393,273	519,881	156,078	1,038,201
2027	3,677,764	1,091,731	2,920,645	222,701	579,927	317,101	480,068	167,172	819,064
2028	2,991,843	811,290	3,817,679	360,534	435,432	240,102	385,570	187,487	571,428
2029	2,305,921	629,845	4,198,793	276,854	338,557	187,835	295,418	144,426	432,985
2030	1,620,000	550,194	2,882,753	231,882	295,412	164,415	256,135	121,962	-
2031	1,458,000	496,626	2,957,038	213,644	262,290	145,762	230,531	109,147	-
2032	1,296,000	461,739	2,823,141	187,525	226,122	127,262	199,112	94,241	-
2033	1,134,000	410,730	2,828,792	158,824	200,937	109,031	171,174	83,304	-
2034	972,000	361,878	2,780,984	136,906	165,578	93,414	144,128	70,096	-
2035	810,000	303,939	2,825,533	109,880	140,332	77,564	120,283	58,001	-
2036	648,000	254,336	2,695,013	78,402	113,496	62,321	95,522	43,923	-
2037	486,000	192,423	2,732,068	66,499	80,170	44,470	68,615	33,822	-
2038	324,000	133,719	2,617,541	40,467	52,898	29,551	46,191	21,175	-
2039	162,000	68,292	2,594,418	18,400	26,833	14,838	23,117	10,520	-
2040	-	-	2,475,750	-	-	-	-	-	-
2041	-	-	2,459,879	-	-	-	-	-	-
2042	-	-	2,209,453	-	-	-	-	-	-
2043	-	-	2,300,472	-	-	-	-	-	-

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual GHG emissions based on the DEQ methodology over the study period under Reference Case assumptions
For each year, break out the contributions of individual fossil fuel resources, market purchases, and market sales to the total GHG emissions per the DEQ methodology
UM 2225 Order Summary/Rubric references: C.4(a)

PGE note: Forecasts of generation from existing thermal output are based on economic dispatch using prices forecasted in this CEP/IRP. Forecasts of unspecified and other emitting market purchases are a function of historical purchases and a linear decline emission reduction glidepath. Neither reflect operational realities.

26	Portfolio26	Hydrogen blending		PGE owned GHG emitting generation (retail)					
		Included in retail total	*Not included in retail total*	Beaver	Carty	Coyote	PW1	PW2	Colstrip
Year	Total Retail GHG Emissions (metric tons)	Market Purchases (metric tons)	Market sales (metric tons)	Fossil fuel resource 1 (metric tons)	Fossil fuel resource 2 (metric tons)	Fossil fuel resource 3 (metric tons)	Fossil fuel resource 4 (metric tons)	Fossil fuel resource 5 (metric tons)	Fossil fuel resource 6 (metric tons)
2023	5,887,117	2,351,875	2,097,049	41,539	919,175	509,985	641,895	130,219	1,292,430
2024	5,308,316	1,802,933	1,865,467	137,208	879,158	490,395	635,821	175,051	1,187,749
2025	5,049,607	1,705,195	1,790,077	142,367	837,292	463,866	563,301	176,532	1,161,054
2026	4,363,686	1,366,816	2,265,765	167,981	721,455	393,273	519,881	156,078	1,038,201
2027	3,677,764	1,091,731	2,920,645	222,701	579,927	317,101	480,068	167,172	819,064
2028	2,991,843	811,290	3,817,679	360,534	435,432	240,102	385,570	187,487	571,428
2029	2,305,921	629,845	3,793,839	276,854	338,557	187,835	295,418	144,426	432,985
2030	1,620,000	550,194	2,482,813	231,882	295,412	164,415	256,135	121,962	-
2031	1,458,000	496,626	2,558,656	213,644	262,290	145,762	230,531	109,147	-
2032	1,296,000	461,739	2,451,074	187,525	226,122	127,262	199,112	94,241	-
2033	1,134,000	410,730	2,467,070	158,824	200,937	109,031	171,174	83,304	-
2034	972,000	361,878	2,434,546	136,906	165,578	93,414	144,128	70,096	-
2035	810,000	303,939	2,483,300	109,880	140,332	77,564	120,283	58,001	-
2036	648,000	254,336	2,375,776	78,402	113,496	62,321	95,522	43,923	-
2037	486,000	192,423	2,418,682	66,499	80,170	44,470	68,615	33,822	-
2038	324,000	133,719	2,323,950	40,467	52,898	29,551	46,191	21,175	-
2039	162,000	68,292	2,311,628	18,400	26,833	14,838	23,117	10,520	-
2040	-	-	2,475,750	-	-	-	-	-	-
2041	-	-	2,459,879	-	-	-	-	-	-
2042	-	-	2,209,453	-	-	-	-	-	-
2043	-	-	2,300,472	-	-	-	-	-	-

27	Portfolio27			PGE owned GHG emitting generation (retail)					
		Included in retail total	*Not included in retail total*	Beaver	Carty	Coyote	PW1	PW2	Colstrip
Year	Total Retail GHG Emissions (metric tons)	Market Purchases (metric tons)	Market sales (metric tons)	Fossil fuel resource 1 (metric tons)	Fossil fuel resource 2 (metric tons)	Fossil fuel resource 3 (metric tons)	Fossil fuel resource 4 (metric tons)	Fossil fuel resource 5 (metric tons)	Fossil fuel resource 6 (metric tons)
2023	5,887,117	2,351,875	2,097,049	41,539	919,175	509,985	641,895	130,219	1,292,430
2024	5,308,316	1,802,933	1,865,467	137,208	879,158	490,395	635,821	175,051	1,187,749
2025	5,049,607	1,705,195	1,790,077	142,367	837,292	463,866	563,301	176,532	1,161,054
2026	4,363,686	1,366,816	2,265,765	167,981	721,455	393,273	519,881	156,078	1,038,201
2027	3,677,764	1,091,731	2,920,645	222,701	579,927	317,101	480,068	167,172	819,064
2028	2,991,843	811,290	3,817,679	360,534	435,432	240,102	385,570	187,487	571,428
2029	2,305,921	629,845	4,198,793	276,854	338,557	187,835	295,418	144,426	432,985
2030	1,620,000	550,194	2,882,753	231,882	295,412	164,415	256,135	121,962	-
2031	1,458,000	496,626	2,957,038	213,644	262,290	145,762	230,531	109,147	-
2032	1,296,000	461,739	2,823,141	187,525	226,122	127,262	199,112	94,241	-
2033	1,134,000	410,730	2,828,792	158,824	200,937	109,031	171,174	83,304	-
2034	972,000	361,878	2,780,984	136,906	165,578	93,414	144,128	70,096	-
2035	810,000	303,939	2,825,533	109,880	140,332	77,564	120,283	58,001	-
2036	648,000	254,336	2,695,013	78,402	113,496	62,321	95,522	43,923	-
2037	486,000	192,423	2,732,068	66,499	80,170	44,470	68,615	33,822	-
2038	324,000	133,719	2,617,541	40,467	52,898	29,551	46,191	21,175	-
2039	162,000	68,292	2,594,418	18,400	26,833	14,838	23,117	10,520	-
2040	-	-	2,475,750	-	-	-	-	-	-
2041	-	-	2,459,879	-	-	-	-	-	-
2042	-	-	2,209,453	-	-	-	-	-	-
2043	-	-	2,300,472	-	-	-	-	-	-

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual GHG emissions based on the DEQ methodology over the study period under Reference Case assumptions
For each year, break out the contributions of individual fossil fuel resources, market purchases, and market sales to the total GHG emissions per the DEQ methodology
UM 2225 Order Summary/Rubric references: C.4(a)

PGE note: Forecasts of generation from existing thermal output are based on economic dispatch using prices forecasted in this CEP/IRP. Forecasts of unspecified and other emitting market purchases are a function of historical purchases and a linear decline emission reduction glidepath. Neither reflect operational realities.

28 Portfolio28

		Included in retail total	*Not included in retail total*	PGE owned GHG emitting generation (retail)					
				Beaver	Carty	Coyote	PW1	PW2	Colstrip
Year	Total Retail GHG Emissions (metric tons)	Market Purchases (metric tons)	Market sales (metric tons)	Fossil fuel resource 1 (metric tons)	Fossil fuel resource 2 (metric tons)	Fossil fuel resource 3 (metric tons)	Fossil fuel resource 4 (metric tons)	Fossil fuel resource 5 (metric tons)	Fossil fuel resource 6 (metric tons)
2023	5,887,117	2,351,875	2,097,049	41,539	919,175	509,985	641,895	130,219	1,292,430
2024	5,308,316	1,802,933	1,865,467	137,208	879,158	490,395	635,821	175,051	1,187,749
2025	5,049,607	1,705,195	1,790,077	142,367	837,292	463,866	563,301	176,532	1,161,054
2026	4,363,686	1,366,816	2,265,765	167,981	721,455	393,273	519,881	156,078	1,038,201
2027	3,677,764	1,091,731	2,920,645	222,701	579,927	317,101	480,068	167,172	819,064
2028	2,991,843	811,290	3,817,679	360,534	435,432	240,102	385,570	187,487	571,428
2029	2,305,921	629,845	4,198,793	276,854	338,557	187,835	295,418	144,426	432,985
2030	1,620,000	550,194	2,882,753	231,882	295,412	164,415	256,135	121,962	-
2031	1,458,000	496,626	2,957,038	213,644	262,290	145,762	230,531	109,147	-
2032	1,296,000	461,739	2,823,141	187,525	226,122	127,262	199,112	94,241	-
2033	1,134,000	410,730	2,828,792	158,824	200,937	109,031	171,174	83,304	-
2034	972,000	361,878	2,780,984	136,906	165,578	93,414	144,128	70,096	-
2035	810,000	303,939	2,825,533	109,880	140,332	77,564	120,283	58,001	-
2036	648,000	254,336	2,695,013	78,402	113,496	62,321	95,522	43,923	-
2037	486,000	192,423	2,732,068	66,499	80,170	44,470	68,615	33,822	-
2038	324,000	133,719	2,617,541	40,467	52,898	29,551	46,191	21,175	-
2039	162,000	68,292	2,594,418	18,400	26,833	14,838	23,117	10,520	-
2040	-	-	2,475,750	-	-	-	-	-	-
2041	-	-	2,459,879	-	-	-	-	-	-
2042	-	-	2,209,453	-	-	-	-	-	-
2043	-	-	2,300,472	-	-	-	-	-	-

29 Portfolio29

		Included in retail total	*Not included in retail total*	PGE owned GHG emitting generation (retail)					
				Beaver	Carty	Coyote	PW1	PW2	Colstrip
Year	Total Retail GHG Emissions (metric tons)	Market Purchases (metric tons)	Market sales (metric tons)	Fossil fuel resource 1 (metric tons)	Fossil fuel resource 2 (metric tons)	Fossil fuel resource 3 (metric tons)	Fossil fuel resource 4 (metric tons)	Fossil fuel resource 5 (metric tons)	Fossil fuel resource 6 (metric tons)
2023	5,887,117	2,351,875	2,097,049	41,539	919,175	509,985	641,895	130,219	1,292,430
2024	5,308,316	1,802,933	1,865,467	137,208	879,158	490,395	635,821	175,051	1,187,749
2025	5,049,607	1,705,195	1,790,077	142,367	837,292	463,866	563,301	176,532	1,161,054
2026	4,363,686	1,366,816	2,265,765	167,981	721,455	393,273	519,881	156,078	1,038,201
2027	3,677,764	1,091,731	2,920,645	222,701	579,927	317,101	480,068	167,172	819,064
2028	2,991,843	811,290	3,817,679	360,534	435,432	240,102	385,570	187,487	571,428
2029	2,305,921	629,845	4,198,793	276,854	338,557	187,835	295,418	144,426	432,985
2030	1,620,000	550,194	2,882,753	231,882	295,412	164,415	256,135	121,962	-
2031	1,458,000	496,626	2,957,038	213,644	262,290	145,762	230,531	109,147	-
2032	1,296,000	461,739	2,823,141	187,525	226,122	127,262	199,112	94,241	-
2033	1,134,000	410,730	2,828,792	158,824	200,937	109,031	171,174	83,304	-
2034	972,000	361,878	2,780,984	136,906	165,578	93,414	144,128	70,096	-
2035	810,000	303,939	2,825,533	109,880	140,332	77,564	120,283	58,001	-
2036	648,000	254,336	2,695,013	78,402	113,496	62,321	95,522	43,923	-
2037	486,000	192,423	2,732,068	66,499	80,170	44,470	68,615	33,822	-
2038	324,000	133,719	2,617,541	40,467	52,898	29,551	46,191	21,175	-
2039	162,000	68,292	2,594,418	18,400	26,833	14,838	23,117	10,520	-
2040	-	-	2,475,750	-	-	-	-	-	-
2041	-	-	2,459,879	-	-	-	-	-	-
2042	-	-	2,209,453	-	-	-	-	-	-
2043	-	-	2,300,472	-	-	-	-	-	-

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual GHG emissions based on the DEQ methodology over the study period under Reference Case assumptions
For each year, break out the contributions of individual fossil fuel resources, market purchases, and market sales to the total GHG emissions per the DEQ methodology
UM 2225 Order Summary/Rubric references: C.4(a)

PGE note: Forecasts of generation from existing thermal output are based on economic dispatch using prices forecasted in this CEP/IRP. Forecasts of unspecified and other emitting market purchases are a function of historical purchases and a linear decline emission reduction glidepath. Neither reflect operational realities.

30 Portfolio30

		Included in retail total	*Not included in retail total*	PGE owned GHG emitting generation (retail)					
				Beaver	Carty	Coyote	PW1	PW2	Colstrip
Year	Total Retail GHG Emissions (metric tons)	Market Purchases (metric tons)	Market sales (metric tons)	Fossil fuel resource 1 (metric tons)	Fossil fuel resource 2 (metric tons)	Fossil fuel resource 3 (metric tons)	Fossil fuel resource 4 (metric tons)	Fossil fuel resource 5 (metric tons)	Fossil fuel resource 6 (metric tons)
2023	5,887,117	2,351,875	2,097,049	41,539	919,175	509,985	641,895	130,219	1,292,430
2024	5,308,316	1,802,933	1,865,467	137,208	879,158	490,395	635,821	175,051	1,187,749
2025	5,049,607	1,705,195	1,790,077	142,367	837,292	463,866	563,301	176,532	1,161,054
2026	4,363,686	1,366,816	2,265,765	167,981	721,455	393,273	519,881	156,078	1,038,201
2027	3,677,764	1,091,731	2,920,645	222,701	579,927	317,101	480,068	167,172	819,064
2028	2,991,843	811,290	3,817,679	360,534	435,432	240,102	385,570	187,487	571,428
2029	2,305,921	629,845	4,198,793	276,854	338,557	187,835	295,418	144,426	432,985
2030	1,620,000	550,194	2,882,753	231,882	295,412	164,415	256,135	121,962	-
2031	1,458,000	496,626	2,957,038	213,644	262,290	145,762	230,531	109,147	-
2032	1,296,000	461,739	2,823,141	187,525	226,122	127,262	199,112	94,241	-
2033	1,134,000	410,730	2,828,792	158,824	200,937	109,031	171,174	83,304	-
2034	972,000	361,878	2,780,984	136,906	165,578	93,414	144,128	70,096	-
2035	810,000	303,939	2,825,533	109,880	140,332	77,564	120,283	58,001	-
2036	648,000	254,336	2,695,013	78,402	113,496	62,321	95,522	43,923	-
2037	486,000	192,423	2,732,068	66,499	80,170	44,470	68,615	33,822	-
2038	324,000	133,719	2,617,541	40,467	52,898	29,551	46,191	21,175	-
2039	162,000	68,292	2,594,418	18,400	26,833	14,838	23,117	10,520	-
2040	-	-	2,475,750	-	-	-	-	-	-
2041	-	-	2,459,879	-	-	-	-	-	-
2042	-	-	2,209,453	-	-	-	-	-	-
2043	-	-	2,300,472	-	-	-	-	-	-

31 Portfolio31

		Included in retail total	*Not included in retail total*	PGE owned GHG emitting generation (retail)					
				Beaver	Carty	Coyote	PW1	PW2	Colstrip
Year	Total Retail GHG Emissions (metric tons)	Market Purchases (metric tons)	Market sales (metric tons)	Fossil fuel resource 1 (metric tons)	Fossil fuel resource 2 (metric tons)	Fossil fuel resource 3 (metric tons)	Fossil fuel resource 4 (metric tons)	Fossil fuel resource 5 (metric tons)	Fossil fuel resource 6 (metric tons)
2023	5,887,117	2,351,875	2,097,049	41,539	919,175	509,985	641,895	130,219	1,292,430
2024	5,308,316	1,802,933	1,865,467	137,208	879,158	490,395	635,821	175,051	1,187,749
2025	5,049,607	1,705,195	1,790,077	142,367	837,292	463,866	563,301	176,532	1,161,054
2026	4,363,686	1,366,816	2,265,765	167,981	721,455	393,273	519,881	156,078	1,038,201
2027	3,677,764	1,091,731	2,920,645	222,701	579,927	317,101	480,068	167,172	819,064
2028	2,991,843	811,290	3,817,679	360,534	435,432	240,102	385,570	187,487	571,428
2029	2,305,921	629,845	4,198,793	276,854	338,557	187,835	295,418	144,426	432,985
2030	1,620,000	550,194	2,882,753	231,882	295,412	164,415	256,135	121,962	-
2031	1,458,000	496,626	2,957,038	213,644	262,290	145,762	230,531	109,147	-
2032	1,296,000	461,739	2,823,141	187,525	226,122	127,262	199,112	94,241	-
2033	1,134,000	410,730	2,828,792	158,824	200,937	109,031	171,174	83,304	-
2034	972,000	361,878	2,780,984	136,906	165,578	93,414	144,128	70,096	-
2035	810,000	303,939	2,825,533	109,880	140,332	77,564	120,283	58,001	-
2036	648,000	254,336	2,695,013	78,402	113,496	62,321	95,522	43,923	-
2037	486,000	192,423	2,732,068	66,499	80,170	44,470	68,615	33,822	-
2038	324,000	133,719	2,617,541	40,467	52,898	29,551	46,191	21,175	-
2039	162,000	68,292	2,594,418	18,400	26,833	14,838	23,117	10,520	-
2040	-	-	2,475,750	-	-	-	-	-	-
2041	-	-	2,459,879	-	-	-	-	-	-
2042	-	-	2,209,453	-	-	-	-	-	-
2043	-	-	2,300,472	-	-	-	-	-	-

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual GHG emissions based on the DEQ methodology over the study period under Reference Case assumptions
For each year, break out the contributions of individual fossil fuel resources, market purchases, and market sales to the total GHG emissions per the DEQ methodology
UM 2225 Order Summary/Rubric references: C.4(a)

PGE note: Forecasts of generation from existing thermal output are based on economic dispatch using prices forecasted in this CEP/IRP. Forecasts of unspecified and other emitting market purchases are a function of historical purchases and a linear decline emission reduction glidepath. Neither reflect operational realities.

32 Portfolio32

		Included in retail total	*Not included in retail total*	PGE owned GHG emitting generation (retail)					
				Beaver	Carty	Coyote	PW1	PW2	Colstrip
Year	Total Retail GHG Emissions (metric tons)	Market Purchases (metric tons)	Market sales (metric tons)	Fossil fuel resource 1 (metric tons)	Fossil fuel resource 2 (metric tons)	Fossil fuel resource 3 (metric tons)	Fossil fuel resource 4 (metric tons)	Fossil fuel resource 5 (metric tons)	Fossil fuel resource 6 (metric tons)
2023	5,887,117	2,351,875	2,097,049	41,539	919,175	509,985	641,895	130,219	1,292,430
2024	5,308,316	1,802,933	1,865,467	137,208	879,158	490,395	635,821	175,051	1,187,749
2025	5,049,607	1,705,195	1,790,077	142,367	837,292	463,866	563,301	176,532	1,161,054
2026	4,363,686	1,366,816	2,265,765	167,981	721,455	393,273	519,881	156,078	1,038,201
2027	3,677,764	1,091,731	2,920,645	222,701	579,927	317,101	480,068	167,172	819,064
2028	2,991,843	811,290	3,817,679	360,534	435,432	240,102	385,570	187,487	571,428
2029	2,305,921	629,845	4,198,793	276,854	338,557	187,835	295,418	144,426	432,985
2030	1,620,000	550,194	2,882,753	231,882	295,412	164,415	256,135	121,962	-
2031	1,458,000	496,626	2,957,038	213,644	262,290	145,762	230,531	109,147	-
2032	1,296,000	461,739	2,823,141	187,525	226,122	127,262	199,112	94,241	-
2033	1,134,000	410,730	2,828,792	158,824	200,937	109,031	171,174	83,304	-
2034	972,000	361,878	2,780,984	136,906	165,578	93,414	144,128	70,096	-
2035	810,000	303,939	2,825,533	109,880	140,332	77,564	120,283	58,001	-
2036	648,000	254,336	2,695,013	78,402	113,496	62,321	95,522	43,923	-
2037	486,000	192,423	2,732,068	66,499	80,170	44,470	68,615	33,822	-
2038	324,000	133,719	2,617,541	40,467	52,898	29,551	46,191	21,175	-
2039	162,000	68,292	2,594,418	18,400	26,833	14,838	23,117	10,520	-
2040	-	-	2,475,750	-	-	-	-	-	-
2041	-	-	2,459,879	-	-	-	-	-	-
2042	-	-	2,209,453	-	-	-	-	-	-
2043	-	-	2,300,472	-	-	-	-	-	-

33 Portfolio33

		Included in retail total	*Not included in retail total*	PGE owned GHG emitting generation (retail)					
				Beaver	Carty	Coyote	PW1	PW2	Colstrip
Year	Total Retail GHG Emissions (metric tons)	Market Purchases (metric tons)	Market sales (metric tons)	Fossil fuel resource 1 (metric tons)	Fossil fuel resource 2 (metric tons)	Fossil fuel resource 3 (metric tons)	Fossil fuel resource 4 (metric tons)	Fossil fuel resource 5 (metric tons)	Fossil fuel resource 6 (metric tons)
2023	5,887,117	2,351,875	2,097,049	41,539	919,175	509,985	641,895	130,219	1,292,430
2024	5,308,316	1,802,933	1,865,467	137,208	879,158	490,395	635,821	175,051	1,187,749
2025	5,049,607	1,705,195	1,790,077	142,367	837,292	463,866	563,301	176,532	1,161,054
2026	4,363,686	1,366,816	2,265,765	167,981	721,455	393,273	519,881	156,078	1,038,201
2027	3,677,764	1,091,731	2,920,645	222,701	579,927	317,101	480,068	167,172	819,064
2028	2,991,843	811,290	3,817,679	360,534	435,432	240,102	385,570	187,487	571,428
2029	2,305,921	629,845	4,198,793	276,854	338,557	187,835	295,418	144,426	432,985
2030	1,620,000	550,194	2,882,753	231,882	295,412	164,415	256,135	121,962	-
2031	1,458,000	496,626	2,957,038	213,644	262,290	145,762	230,531	109,147	-
2032	1,296,000	461,739	2,823,141	187,525	226,122	127,262	199,112	94,241	-
2033	1,134,000	410,730	2,828,792	158,824	200,937	109,031	171,174	83,304	-
2034	972,000	361,878	2,780,984	136,906	165,578	93,414	144,128	70,096	-
2035	810,000	303,939	2,825,533	109,880	140,332	77,564	120,283	58,001	-
2036	648,000	254,336	2,695,013	78,402	113,496	62,321	95,522	43,923	-
2037	486,000	192,423	2,732,068	66,499	80,170	44,470	68,615	33,822	-
2038	324,000	133,719	2,617,541	40,467	52,898	29,551	46,191	21,175	-
2039	162,000	68,292	2,594,418	18,400	26,833	14,838	23,117	10,520	-
2040	-	-	2,475,750	-	-	-	-	-	-
2041	-	-	2,459,879	-	-	-	-	-	-
2042	-	-	2,209,453	-	-	-	-	-	-
2043	-	-	2,300,472	-	-	-	-	-	-

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual GHG emissions based on the DEQ methodology over the study period under Reference Case assumptions
For each year, break out the contributions of individual fossil fuel resources, market purchases, and market sales to the total GHG emissions per the DEQ methodology
UM 2225 Order Summary/Rubric references: C.4(a)

PGE note: Forecasts of generation from existing thermal output are based on economic dispatch using prices forecasted in this CEP/IRP. Forecasts of unspecified and other emitting market purchases are a function of historical purchases and a linear decline emission reduction glidepath. Neither reflect operational realities.

34	Portfolio34				PGE owned GHG emitting generation (retail)					
		Included in retail total	*Not included in retail total*		Beaver	Carty	Coyote	PW1	PW2	Colstrip
Year	Total Retail GHG Emissions (metric tons)	Market Purchases (metric tons)	Market sales (metric tons)		Fossil fuel resource 1 (metric tons)	Fossil fuel resource 2 (metric tons)	Fossil fuel resource 3 (metric tons)	Fossil fuel resource 4 (metric tons)	Fossil fuel resource 5 (metric tons)	Fossil fuel resource 6 (metric tons)
2023	5,887,117	2,351,875	2,097,049		41,539	919,175	509,985	641,895	130,219	1,292,430
2024	5,308,316	1,802,933	1,865,467		137,208	879,158	490,395	635,821	175,051	1,187,749
2025	5,049,607	1,705,195	1,790,077		142,367	837,292	463,866	563,301	176,532	1,161,054
2026	4,363,686	1,366,816	2,265,765		167,981	721,455	393,273	519,881	156,078	1,038,201
2027	3,677,764	1,091,731	2,920,645		222,701	579,927	317,101	480,068	167,172	819,064
2028	2,991,843	811,290	3,817,679		360,534	435,432	240,102	385,570	187,487	571,428
2029	2,305,921	629,845	4,198,793		276,854	338,557	187,835	295,418	144,426	432,985
2030	1,620,000	550,194	2,882,753		231,882	295,412	164,415	256,135	121,962	-
2031	1,458,000	496,626	2,957,038		213,644	262,290	145,762	230,531	109,147	-
2032	1,296,000	461,739	2,823,141		187,525	226,122	127,262	199,112	94,241	-
2033	1,134,000	410,730	2,828,792		158,824	200,937	109,031	171,174	83,304	-
2034	972,000	361,878	2,780,984		136,906	165,578	93,414	144,128	70,096	-
2035	810,000	303,939	2,825,533		109,880	140,332	77,564	120,283	58,001	-
2036	648,000	254,336	2,695,013		78,402	113,496	62,321	95,522	43,923	-
2037	486,000	192,423	2,732,068		66,499	80,170	44,470	68,615	33,822	-
2038	324,000	133,719	2,617,541		40,467	52,898	29,551	46,191	21,175	-
2039	162,000	68,292	2,594,418		18,400	26,833	14,838	23,117	10,520	-
2040	-	-	2,475,750		-	-	-	-	-	-
2041	-	-	2,459,879		-	-	-	-	-	-
2042	-	-	2,209,453		-	-	-	-	-	-
2043	-	-	2,300,472		-	-	-	-	-	-

35	Portfolio35				PGE owned GHG emitting generation (retail)					
		Included in retail total	*Not included in retail total*		Beaver	Carty	Coyote	PW1	PW2	Colstrip
Year	Total Retail GHG Emissions (metric tons)	Market Purchases (metric tons)	Market sales (metric tons)		Fossil fuel resource 1 (metric tons)	Fossil fuel resource 2 (metric tons)	Fossil fuel resource 3 (metric tons)	Fossil fuel resource 4 (metric tons)	Fossil fuel resource 5 (metric tons)	Fossil fuel resource 6 (metric tons)
2023	5,887,117	2,351,875	2,097,049		41,539	919,175	509,985	641,895	130,219	1,292,430
2024	5,308,316	1,802,933	1,865,467		137,208	879,158	490,395	635,821	175,051	1,187,749
2025	5,049,607	1,705,195	1,790,077		142,367	837,292	463,866	563,301	176,532	1,161,054
2026	4,363,686	1,366,816	2,265,765		167,981	721,455	393,273	519,881	156,078	1,038,201
2027	3,677,764	1,091,731	2,920,645		222,701	579,927	317,101	480,068	167,172	819,064
2028	2,991,843	811,290	3,817,679		360,534	435,432	240,102	385,570	187,487	571,428
2029	2,305,921	629,845	4,198,793		276,854	338,557	187,835	295,418	144,426	432,985
2030	1,620,000	550,194	2,882,753		231,882	295,412	164,415	256,135	121,962	-
2031	1,458,000	496,626	2,957,038		213,644	262,290	145,762	230,531	109,147	-
2032	1,296,000	461,739	2,823,141		187,525	226,122	127,262	199,112	94,241	-
2033	1,134,000	410,730	2,828,792		158,824	200,937	109,031	171,174	83,304	-
2034	972,000	361,878	2,780,984		136,906	165,578	93,414	144,128	70,096	-
2035	810,000	303,939	2,825,533		109,880	140,332	77,564	120,283	58,001	-
2036	648,000	254,336	2,695,013		78,402	113,496	62,321	95,522	43,923	-
2037	486,000	192,423	2,732,068		66,499	80,170	44,470	68,615	33,822	-
2038	324,000	133,719	2,617,541		40,467	52,898	29,551	46,191	21,175	-
2039	162,000	68,292	2,594,418		18,400	26,833	14,838	23,117	10,520	-
2040	-	-	2,475,750		-	-	-	-	-	-
2041	-	-	2,459,879		-	-	-	-	-	-
2042	-	-	2,209,453		-	-	-	-	-	-
2043	-	-	2,300,472		-	-	-	-	-	-

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual GHG emissions based on the DEQ methodology over the study period under Reference Case assumptions
For each year, break out the contributions of individual fossil fuel resources, market purchases, and market sales to the total GHG emissions per the DEQ methodology
UM 2225 Order Summary/Rubric references: C.4(a)

PGE note: Forecasts of generation from existing thermal output are based on economic dispatch using prices forecasted in this CEP/IRP. Forecasts of unspecified and other emitting market purchases are a function of historical purchases and a linear decline emission reduction glidepath. Neither reflect operational realities.

36	Portfolio36				PGE owned GHG emitting generation (retail)					
		Included in retail total	*Not included in retail total*	Beaver	Carty	Coyote	PW1	PW2	Colstrip
Year	Total Retail GHG Emissions (metric tons)	Market Purchases (metric tons)	Market sales (metric tons)	Fossil fuel resource 1 (metric tons)	Fossil fuel resource 2 (metric tons)	Fossil fuel resource 3 (metric tons)	Fossil fuel resource 4 (metric tons)	Fossil fuel resource 5 (metric tons)	Fossil fuel resource 6 (metric tons)
2023	5,887,117	2,351,875	2,097,049	41,539	919,175	509,985	641,895	130,219	1,292,430
2024	5,308,316	1,802,933	1,865,467	137,208	879,158	490,395	635,821	175,051	1,187,749
2025	5,049,607	1,705,195	1,790,077	142,367	837,292	463,866	563,301	176,532	1,161,054
2026	4,363,686	1,366,816	2,265,765	167,981	721,455	393,273	519,881	156,078	1,038,201
2027	3,677,764	1,091,731	2,920,645	222,701	579,927	317,101	480,068	167,172	819,064
2028	2,991,843	811,290	3,817,679	360,534	435,432	240,102	385,570	187,487	571,428
2029	2,305,921	629,845	4,198,793	276,854	338,557	187,835	295,418	144,426	432,985
2030	1,620,000	550,194	2,882,753	231,882	295,412	164,415	256,135	121,962	-
2031	1,458,000	496,626	2,957,038	213,644	262,290	145,762	230,531	109,147	-
2032	1,296,000	461,739	2,823,141	187,525	226,122	127,262	199,112	94,241	-
2033	1,134,000	410,730	2,828,792	158,824	200,937	109,031	171,174	83,304	-
2034	972,000	361,878	2,780,984	136,906	165,578	93,414	144,128	70,096	-
2035	810,000	303,939	2,825,533	109,880	140,332	77,564	120,283	58,001	-
2036	648,000	254,336	2,695,013	78,402	113,496	62,321	95,522	43,923	-
2037	486,000	192,423	2,732,068	66,499	80,170	44,470	68,615	33,822	-
2038	324,000	133,719	2,617,541	40,467	52,898	29,551	46,191	21,175	-
2039	162,000	68,292	2,594,418	18,400	26,833	14,838	23,117	10,520	-
2040	-	-	2,475,750	-	-	-	-	-	-
2041	-	-	2,459,879	-	-	-	-	-	-
2042	-	-	2,209,453	-	-	-	-	-	-
2043	-	-	2,300,472	-	-	-	-	-	-

37	Portfolio37				PGE owned GHG emitting generation (retail)					
		Included in retail total	*Not included in retail total*	Beaver	Carty	Coyote	PW1	PW2	Colstrip
Year	Total Retail GHG Emissions (metric tons)	Market Purchases (metric tons)	Market sales (metric tons)	Fossil fuel resource 1 (metric tons)	Fossil fuel resource 2 (metric tons)	Fossil fuel resource 3 (metric tons)	Fossil fuel resource 4 (metric tons)	Fossil fuel resource 5 (metric tons)	Fossil fuel resource 6 (metric tons)
2023	5,887,117	2,351,875	2,097,049	41,539	919,175	509,985	641,895	130,219	1,292,430
2024	5,308,316	1,802,933	1,865,467	137,208	879,158	490,395	635,821	175,051	1,187,749
2025	5,049,607	1,705,195	1,790,077	142,367	837,292	463,866	563,301	176,532	1,161,054
2026	4,363,686	1,366,816	2,265,765	167,981	721,455	393,273	519,881	156,078	1,038,201
2027	3,677,764	1,091,731	2,920,645	222,701	579,927	317,101	480,068	167,172	819,064
2028	2,991,843	811,290	3,817,679	360,534	435,432	240,102	385,570	187,487	571,428
2029	2,305,921	629,845	4,198,793	276,854	338,557	187,835	295,418	144,426	432,985
2030	1,620,000	550,194	2,882,753	231,882	295,412	164,415	256,135	121,962	-
2031	1,458,000	496,626	2,957,038	213,644	262,290	145,762	230,531	109,147	-
2032	1,296,000	461,739	2,823,141	187,525	226,122	127,262	199,112	94,241	-
2033	1,134,000	410,730	2,828,792	158,824	200,937	109,031	171,174	83,304	-
2034	972,000	361,878	2,780,984	136,906	165,578	93,414	144,128	70,096	-
2035	810,000	303,939	2,825,533	109,880	140,332	77,564	120,283	58,001	-
2036	648,000	254,336	2,695,013	78,402	113,496	62,321	95,522	43,923	-
2037	486,000	192,423	2,732,068	66,499	80,170	44,470	68,615	33,822	-
2038	324,000	133,719	2,617,541	40,467	52,898	29,551	46,191	21,175	-
2039	162,000	68,292	2,594,418	18,400	26,833	14,838	23,117	10,520	-
2040	-	-	2,475,750	-	-	-	-	-	-
2041	-	-	2,459,879	-	-	-	-	-	-
2042	-	-	2,209,453	-	-	-	-	-	-
2043	-	-	2,300,472	-	-	-	-	-	-

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual GHG emissions based on the DEQ methodology over the study period under Reference Case assumptions
For each year, break out the contributions of individual fossil fuel resources, market purchases, and market sales to the total GHG emissions per the DEQ methodology
UM 2225 Order Summary/Rubric references: C.4(a)

PGE note: Forecasts of generation from existing thermal output are based on economic dispatch using prices forecasted in this CEP/IRP. Forecasts of unspecified and other emitting market purchases are a function of historical purchases and a linear decline emission reduction glidepath. Neither reflect operational realities.

38 Portfolio38

		Included in retail total	*Not included in retail total*	PGE owned GHG emitting generation (retail)					
				Beaver	Carty	Coyote	PW1	PW2	Colstrip
Year	Total Retail GHG Emissions (metric tons)	Market Purchases (metric tons)	Market sales (metric tons)	Fossil fuel resource 1 (metric tons)	Fossil fuel resource 2 (metric tons)	Fossil fuel resource 3 (metric tons)	Fossil fuel resource 4 (metric tons)	Fossil fuel resource 5 (metric tons)	Fossil fuel resource 6 (metric tons)
2023	5,887,117	2,351,875	2,097,049	41,539	919,175	509,985	641,895	130,219	1,292,430
2024	5,308,316	1,802,933	1,865,467	137,208	879,158	490,395	635,821	175,051	1,187,749
2025	5,049,607	1,705,195	1,790,077	142,367	837,292	463,866	563,301	176,532	1,161,054
2026	4,363,686	1,366,816	2,265,765	167,981	721,455	393,273	519,881	156,078	1,038,201
2027	3,677,764	1,091,731	2,920,645	222,701	579,927	317,101	480,068	167,172	819,064
2028	2,991,843	811,290	3,817,679	360,534	435,432	240,102	385,570	187,487	571,428
2029	2,305,921	629,845	4,198,793	276,854	338,557	187,835	295,418	144,426	432,985
2030	1,620,000	550,194	2,882,753	231,882	295,412	164,415	256,135	121,962	-
2031	1,458,000	496,626	2,957,038	213,644	262,290	145,762	230,531	109,147	-
2032	1,296,000	461,739	2,823,141	187,525	226,122	127,262	199,112	94,241	-
2033	1,134,000	410,730	2,828,792	158,824	200,937	109,031	171,174	83,304	-
2034	972,000	361,878	2,780,984	136,906	165,578	93,414	144,128	70,096	-
2035	810,000	303,939	2,825,533	109,880	140,332	77,564	120,283	58,001	-
2036	648,000	254,336	2,695,013	78,402	113,496	62,321	95,522	43,923	-
2037	486,000	192,423	2,732,068	66,499	80,170	44,470	68,615	33,822	-
2038	324,000	133,719	2,617,541	40,467	52,898	29,551	46,191	21,175	-
2039	162,000	68,292	2,594,418	18,400	26,833	14,838	23,117	10,520	-
2040	-	-	2,475,750	-	-	-	-	-	-
2041	-	-	2,459,879	-	-	-	-	-	-
2042	-	-	2,209,453	-	-	-	-	-	-
2043	-	-	2,300,472	-	-	-	-	-	-

39 Portfolio39

		Included in retail total	*Not included in retail total*	PGE owned GHG emitting generation (retail)					
				Beaver	Carty	Coyote	PW1	PW2	Colstrip
Year	Total Retail GHG Emissions (metric tons)	Market Purchases (metric tons)	Market sales (metric tons)	Fossil fuel resource 1 (metric tons)	Fossil fuel resource 2 (metric tons)	Fossil fuel resource 3 (metric tons)	Fossil fuel resource 4 (metric tons)	Fossil fuel resource 5 (metric tons)	Fossil fuel resource 6 (metric tons)
2023	5,887,117	2,351,875	2,097,049	41,539	919,175	509,985	641,895	130,219	1,292,430
2024	5,308,316	1,802,933	1,865,467	137,208	879,158	490,395	635,821	175,051	1,187,749
2025	5,049,607	1,705,195	1,790,077	142,367	837,292	463,866	563,301	176,532	1,161,054
2026	4,363,686	1,366,816	2,265,765	167,981	721,455	393,273	519,881	156,078	1,038,201
2027	3,677,764	1,091,731	2,920,645	222,701	579,927	317,101	480,068	167,172	819,064
2028	2,991,843	811,290	3,817,679	360,534	435,432	240,102	385,570	187,487	571,428
2029	2,305,921	629,845	4,198,793	276,854	338,557	187,835	295,418	144,426	432,985
2030	1,620,000	550,194	2,882,753	231,882	295,412	164,415	256,135	121,962	-
2031	1,458,000	496,626	2,957,038	213,644	262,290	145,762	230,531	109,147	-
2032	1,296,000	461,739	2,823,141	187,525	226,122	127,262	199,112	94,241	-
2033	1,134,000	410,730	2,828,792	158,824	200,937	109,031	171,174	83,304	-
2034	972,000	361,878	2,780,984	136,906	165,578	93,414	144,128	70,096	-
2035	810,000	303,939	2,825,533	109,880	140,332	77,564	120,283	58,001	-
2036	648,000	254,336	2,695,013	78,402	113,496	62,321	95,522	43,923	-
2037	486,000	192,423	2,732,068	66,499	80,170	44,470	68,615	33,822	-
2038	324,000	133,719	2,617,541	40,467	52,898	29,551	46,191	21,175	-
2039	162,000	68,292	2,594,418	18,400	26,833	14,838	23,117	10,520	-
2040	-	-	2,475,750	-	-	-	-	-	-
2041	-	-	2,459,879	-	-	-	-	-	-
2042	-	-	2,209,453	-	-	-	-	-	-
2043	-	-	2,300,472	-	-	-	-	-	-

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual Customer Benefits Indicators (CBIs) over the study period under Reference Case assumptions

UM 2225 Order Summary/Rubric references: C.4(b)

40	Portfolio40			Preferred Portfolio							
Year	CBRE Solar (pCBI)	CBRE Micro (pCBI)	CBRE Hydrc (pCBI)	rCBI (2023$)	CBI 5 (units)	CBI 6 (units)	CBI 7 (units)	CBI 8 (units)	CBI 9 (units)	CBI 10 (units)	…
2023	0	0	0	-							
2024	0	0	0	-							
2025	0	0	0	-							
2026	22	43	1	1,432,417							
2027	28	56	1	1,844,283							
2028	36	71	3	2,385,915							
2029	43	85	5	2,885,015							
2030	50	100	5	3,363,066							
2031	50	100	5	3,363,934							
2032	50	100	5	3,364,151							
2033	50	100	5	3,364,151							
2034	50	100	5	3,364,151							
2035	50	100	5	3,364,151							
2036	50	100	5	3,364,151							
2037	50	100	5	3,364,151							
2038	50	100	5	3,364,151							
2039	50	100	5	3,364,151							
2040	50	100	5	3,364,151							
2041	50	100	5	3,364,151							
2042	50	100	5	3,364,151							
2043	50	100	5	3,364,151							

1	Portfolio1										
Year	CBRE Solar (pCBI)	CBRE Micro (pCBI)	CBRE Hydrc (pCBI)	rCBI (2023$)	CBI 5 (units)	CBI 6 (units)	CBI 7 (units)	CBI 8 (units)	CBI 9 (units)	CBI 10 (units)	…
2023	0	0	0	-							
2024	0	0	0	-							
2025	0	0	0	-							
2026	22	43	1	1,432,417							
2027	28	56	1	1,844,283							
2028	36	71	3	2,386,132							
2029	43	85	5	2,885,666							
2030	50	100	5	3,363,717							
2031	50	100	5	3,363,934							
2032	50	100	5	3,364,151							
2033	50	100	5	3,364,151							
2034	50	100	5	3,364,151							
2035	50	100	5	3,364,151							
2036	50	100	5	3,364,151							
2037	50	100	5	3,364,151							
2038	50	100	5	3,364,151							
2039	50	100	5	3,364,151							
2040	50	100	5	3,364,151							
2041	50	100	5	3,364,151							
2042	50	100	5	3,364,151							
2043	50	100	5	3,364,151							

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual Customer Benefits Indicators (CBIs) over the study period under Reference Case assumptions

UM 2225 Order Summary/Rubric references: C.4(b)

2 Portfolio2

Year	CBRE Solar (pCBI)	CBRE Micro (pCBI)	CBRE Hydrc (pCBI)	rCBI (2023$)	CBI 5 (units)	CBI 6 (units)	CBI 7 (units)	CBI 8 (units)	CBI 9 (units)	CBI 10 (units)	…
2023	0	0	0	-							
2024	0	0	0	-							
2025	0	0	0	-							
2026	22	43	1	1,432,417							
2027	28	56	1	1,844,283							
2028	36	71	3	2,387,000							
2029	43	85	5	2,886,751							
2030	50	100	5	3,364,151							
2031	50	100	5	3,364,151							
2032	50	100	5	3,364,151							
2033	50	100	5	3,364,151							
2034	50	100	5	3,364,151							
2035	50	100	5	3,364,151							
2036	50	100	5	3,364,151							
2037	50	100	5	3,364,151							
2038	50	100	5	3,364,151							
2039	50	100	5	3,364,151							
2040	50	100	5	3,364,151							
2041	50	100	5	3,364,151							
2042	50	100	5	3,364,151							
2043	50	100	5	3,364,151							

3 Portfolio3

Year	CBRE Solar (pCBI)	CBRE Micro (pCBI)	CBRE Hydrc (pCBI)	rCBI (2023$)	CBI 5 (units)	CBI 6 (units)	CBI 7 (units)	CBI 8 (units)	CBI 9 (units)	CBI 10 (units)	…
2023	0	0	0	-							
2024	0	0	0	-							
2025	0	0	0	-							
2026	22	43	1	1,432,200							
2027	28	56	1	1,844,066							
2028	36	71	3	2,385,915							
2029	43	85	5	2,885,666							
2030	50	100	5	3,363,717							
2031	50	100	5	3,363,934							
2032	50	100	5	3,364,151							
2033	50	100	5	3,364,151							
2034	50	100	5	3,364,151							
2035	50	100	5	3,364,151							
2036	50	100	5	3,364,151							
2037	50	100	5	3,364,151							
2038	50	100	5	3,364,151							
2039	50	100	5	3,364,151							
2040	50	100	5	3,364,151							
2041	50	100	5	3,364,151							
2042	50	100	5	3,364,151							
2043	50	100	5	3,364,151							

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual Customer Benefits Indicators (CBIs) over the study period under Reference Case assumptions

UM 2225 Order Summary/Rubric references: C.4(b)

4 Portfolio4

Year	CBRE Solar (pCBI)	CBRE Micro (pCBI)	CBRE Hydrc (pCBI)	rCBI (2023$)	CBI 5 (units)	CBI 6 (units)	CBI 7 (units)	CBI 8 (units)	CBI 9 (units)	CBI 10 (units)	…
2023	0	0	0	-							
2024	0	0	0	-							
2025	0	0	0	-							
2026	22	43	1	1,432,417							
2027	28	56	1	1,844,283							
2028	36	71	3	2,385,915							
2029	43	85	5	2,885,232							
2030	50	100	5	3,363,283							
2031	50	100	5	3,363,934							
2032	50	100	5	3,364,151							
2033	50	100	5	3,364,151							
2034	50	100	5	3,364,151							
2035	50	100	5	3,364,151							
2036	50	100	5	3,364,151							
2037	50	100	5	3,364,151							
2038	50	100	5	3,364,151							
2039	50	100	5	3,364,151							
2040	50	100	5	3,364,151							
2041	50	100	5	3,364,151							
2042	50	100	5	3,364,151							
2043	50	100	5	3,364,151							

5 Portfolio5

Year	CBRE Solar (pCBI)	CBRE Micro (pCBI)	CBRE Hydrc (pCBI)	rCBI (2023$)	CBI 5 (units)	CBI 6 (units)	CBI 7 (units)	CBI 8 (units)	CBI 9 (units)	CBI 10 (units)	…
2023	0	0	0	-							
2024	0	0	0	-							
2025	0	0	0	-							
2026	22	43	1	1,432,417							
2027	28	56	1	1,844,283							
2028	36	71	3	2,387,000							
2029	43	85	5	2,886,751							
2030	50	100	5	3,364,151							
2031	50	100	5	3,364,151							
2032	50	100	5	3,364,151							
2033	50	100	5	3,364,151							
2034	50	100	5	3,364,151							
2035	50	100	5	3,364,151							
2036	50	100	5	3,364,151							
2037	50	100	5	3,364,151							
2038	50	100	5	3,364,151							
2039	50	100	5	3,364,151							
2040	50	100	5	3,364,151							
2041	50	100	5	3,364,151							
2042	50	100	5	3,364,151							
2043	50	100	5	3,364,151							

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual Customer Benefits Indicators (CBIs) over the study period under Reference Case assumptions

UM 2225 Order Summary/Rubric references: C.4(b)

6 Portfolio6

Year	CBRE Solar (pCBI)	CBRE Micro (pCBI)	CBRE Hydrc (pCBI)	rCBI (2023$)	CBI 5 (units)	CBI 6 (units)	CBI 7 (units)	CBI 8 (units)	CBI 9 (units)	CBI 10 (units)	…
2023	0	0	0	-							
2024	0	0	0	-							
2025	0	0	0	-							
2026	22	43	1	1,431,983							
2027	28	56	1	1,843,849							
2028	36	71	3	2,385,481							
2029	43	85	5	2,885,232							
2030	50	100	5	3,363,283							
2031	50	100	5	3,363,934							
2032	50	100	5	3,364,151							
2033	50	100	5	3,364,151							
2034	50	100	5	3,364,151							
2035	50	100	5	3,364,151							
2036	50	100	5	3,364,151							
2037	50	100	5	3,364,151							
2038	50	100	5	3,364,151							
2039	50	100	5	3,364,151							
2040	50	100	5	3,364,151							
2041	50	100	5	3,364,151							
2042	50	100	5	3,364,151							
2043	50	100	5	3,364,151							

7 Portfolio7

Year	CBRE Solar (pCBI)	CBRE Micro (pCBI)	CBRE Hydrc (pCBI)	rCBI (2023$)	CBI 5 (units)	CBI 6 (units)	CBI 7 (units)	CBI 8 (units)	CBI 9 (units)	CBI 10 (units)	…
2023	0	0	0	-							
2024	0	0	0	-							
2025	0	0	0	-							
2026	22	43	1	1,432,200							
2027	28	56	1	1,844,066							
2028	36	71	3	2,385,915							
2029	43	85	5	2,885,666							
2030	50	100	5	3,363,717							
2031	50	100	5	3,363,934							
2032	50	100	5	3,364,151							
2033	50	100	5	3,364,151							
2034	50	100	5	3,364,151							
2035	50	100	5	3,364,151							
2036	50	100	5	3,364,151							
2037	50	100	5	3,364,151							
2038	50	100	5	3,364,151							
2039	50	100	5	3,364,151							
2040	50	100	5	3,364,151							
2041	50	100	5	3,364,151							
2042	50	100	5	3,364,151							
2043	50	100	5	3,364,151							

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual Customer Benefits Indicators (CBIs) over the study period under Reference Case assumptions

UM 2225 Order Summary/Rubric references: C.4(b)

8 Portfolio8

Year	CBRE Solar (pCBI)	CBRE Micro (pCBI)	CBRE Hydrc (pCBI)	rCBI (2023$)	CBI 5 (units)	CBI 6 (units)	CBI 7 (units)	CBI 8 (units)	CBI 9 (units)	CBI 10 (units)	…
2023	0	0	0	-							
2024	0	0	0	-							
2025	0	0	0	-							
2026	22	43	1	1,431,983							
2027	28	56	1	1,843,849							
2028	36	71	3	2,385,481							
2029	43	85	5	2,885,232							
2030	50	100	5	3,363,283							
2031	50	100	5	3,363,934							
2032	50	100	5	3,364,151							
2033	50	100	5	3,364,151							
2034	50	100	5	3,364,151							
2035	50	100	5	3,364,151							
2036	50	100	5	3,364,151							
2037	50	100	5	3,364,151							
2038	50	100	5	3,364,151							
2039	50	100	5	3,364,151							
2040	50	100	5	3,364,151							
2041	50	100	5	3,364,151							
2042	50	100	5	3,364,151							
2043	50	100	5	3,364,151							

9 Portfolio9

Year	CBRE Solar (pCBI)	CBRE Micro (pCBI)	CBRE Hydrc (pCBI)	rCBI (2023$)	CBI 5 (units)	CBI 6 (units)	CBI 7 (units)	CBI 8 (units)	CBI 9 (units)	CBI 10 (units)	…
2023	0	0	0	-							
2024	0	0	0	-							
2025	0	0	0	-							
2026	22	43	1	1,432,200							
2027	28	56	1	1,844,066							
2028	36	71	3	2,385,915							
2029	43	85	5	2,885,666							
2030	50	100	5	3,363,717							
2031	50	100	5	3,363,934							
2032	50	100	5	3,364,151							
2033	50	100	5	3,364,151							
2034	50	100	5	3,364,151							
2035	50	100	5	3,364,151							
2036	50	100	5	3,364,151							
2037	50	100	5	3,364,151							
2038	50	100	5	3,364,151							
2039	50	100	5	3,364,151							
2040	50	100	5	3,364,151							
2041	50	100	5	3,364,151							
2042	50	100	5	3,364,151							
2043	50	100	5	3,364,151							

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual Customer Benefits Indicators (CBIs) over the study period under Reference Case assumptions

UM 2225 Order Summary/Rubric references: C.4(b)

10 Portfolio10

Year	CBRE Solar (pCBI)	CBRE Micro (pCBI)	CBRE Hydrc (pCBI)	rCBI (2023$)	CBI 5 (units)	CBI 6 (units)	CBI 7 (units)	CBI 8 (units)	CBI 9 (units)	CBI 10 (units)	…
2023	0	0	0	-							
2024	0	0	0	-							
2025	0	0	0	-							
2026	17	32	1	1,081,528							
2027	21	42	1	1,392,272							
2028	27	53	2	1,797,194							
2029	32	64	4	2,173,255							
2030	38	75	4	2,534,126							
2031	38	75	4	2,534,777							
2032	38	75	4	2,535,428							
2033	38	75	4	2,536,079							
2034	38	75	4	2,536,730							
2035	38	75	4	2,537,381							
2036	38	75	4	2,538,032							
2037	38	75	4	2,538,683							
2038	38	75	4	2,539,334							
2039	38	75	4	2,539,985							
2040	38	75	4	2,540,636							
2041	38	75	4	2,541,287							
2042	38	75	4	2,541,938							
2043	38	75	4	2,542,589							

11 Portfolio11

Year	CBRE Solar (pCBI)	CBRE Micro (pCBI)	CBRE Hydrc (pCBI)	rCBI (2023$)	CBI 5 (units)	CBI 6 (units)	CBI 7 (units)	CBI 8 (units)	CBI 9 (units)	CBI 10 (units)	…
2023	0	0	0	-							
2024	0	0	0	-							
2025	0	0	0	-							
2026	0	0	0	-							
2027	0	0	0	-							
2028	0	0	0	-							
2029	0	0	0	-							
2030	0	0	0	-							
2031	0	0	0	-							
2032	0	0	0	-							
2033	0	0	0	-							
2034	0	0	0	-							
2035	0	0	0	-							
2036	0	0	0	-							
2037	0	0	0	-							
2038	0	0	0	-							
2039	0	0	0	-							
2040	0	0	0	-							
2041	0	0	0	-							
2042	0	0	0	-							
2043	0	0	0	-							

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual Customer Benefits Indicators (CBIs) over the study period under Reference Case assumptions

UM 2225 Order Summary/Rubric references: C.4(b)

12 Portfolio12

Year	CBRE Solar (pCBI)	CBRE Micro (pCBI)	CBRE Hydrc (pCBI)	rCBI (2023$)	CBI 5 (units)	CBI 6 (units)	CBI 7 (units)	CBI 8 (units)	CBI 9 (units)	CBI 10 (units)	...
2023	0	0	0	-							
2024	0	0	0	-							
2025	0	0	0	-							
2026	0	43	0	933,317							
2027	0	56	0	1,215,200							
2028	0	71	0	1,540,483							
2029	0	85	0	1,844,500							
2030	0	100	0	2,170,217							
2031	0	100	0	2,170,217							
2032	0	100	0	2,170,217							
2033	0	100	0	2,170,217							
2034	0	100	0	2,170,217							
2035	0	100	0	2,170,217							
2036	0	100	0	2,170,217							
2037	0	100	0	2,170,217							
2038	0	100	0	2,170,217							
2039	0	100	0	2,170,217							
2040	0	100	0	2,170,217							
2041	0	100	0	2,170,217							
2042	0	100	0	2,170,217							
2043	0	100	0	2,170,217							

13 Portfolio13

Year	CBRE Solar (pCBI)	CBRE Micro (pCBI)	CBRE Hydrc (pCBI)	rCBI (2023$)	CBI 5 (units)	CBI 6 (units)	CBI 7 (units)	CBI 8 (units)	CBI 9 (units)	CBI 10 (units)	...
2023	0	0	0	-							
2024	0	0	0	-							
2025	0	0	0	-							
2026	22	43	1	1,430,898							
2027	28	56	1	1,842,547							
2028	36	71	3	2,385,047							
2029	43	85	5	2,884,798							
2030	50	100	5	3,362,849							
2031	50	100	5	3,363,283							
2032	50	100	5	3,363,500							
2033	50	100	5	3,363,717							
2034	50	100	5	3,363,934							
2035	50	100	5	3,364,151							
2036	50	100	5	3,364,151							
2037	50	100	5	3,364,151							
2038	50	100	5	3,364,151							
2039	50	100	5	3,364,151							
2040	50	100	5	3,364,151							
2041	50	100	5	3,364,151							
2042	50	100	5	3,364,151							
2043	50	100	5	3,364,151							

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual Customer Benefits Indicators (CBIs) over the study period under Reference Case assumptions

UM 2225 Order Summary/Rubric references: C.4(b)

14 Portfolio14

Year	CBRE Solar (pCBI)	CBRE Micro (pCBI)	CBRE Hydrc (pCBI)	rCBI (2023$)	CBI 5 (units)	CBI 6 (units)	CBI 7 (units)	CBI 8 (units)	CBI 9 (units)	CBI 10 (units)	…
2023	0	0	0	-							
2024	0	0	0	-							
2025	0	0	0	-							
2026	0	0	0	-							
2027	0	0	0	-							
2028	0	0	0	-							
2029	0	0	0	-							
2030	0	0	0	-							
2031	0	0	0	-							
2032	0	0	0	-							
2033	0	0	0	-							
2034	0	0	0	-							
2035	0	0	0	-							
2036	0	0	0	-							
2037	0	0	0	-							
2038	0	0	0	-							
2039	0	0	0	-							
2040	0	0	0	-							
2041	0	0	0	-							
2042	0	0	0	-							
2043	0	0	0	-							

15 Portfolio15

Year	CBRE Solar (pCBI)	CBRE Micro (pCBI)	CBRE Hydrc (pCBI)	rCBI (2023$)	CBI 5 (units)	CBI 6 (units)	CBI 7 (units)	CBI 8 (units)	CBI 9 (units)	CBI 10 (units)	…
2023	0	0	0	-							
2024	0	0	0	-							
2025	0	0	0	-							
2026	22	43	1	1,432,200							
2027	28	56	1	1,844,717							
2028	36	71	3	2,387,868							
2029	43	85	5	2,886,751							
2030	50	100	5	3,364,151							
2031	50	100	5	3,364,151							
2032	50	100	5	3,364,151							
2033	50	100	5	3,364,151							
2034	50	100	5	3,364,151							
2035	50	100	5	3,364,151							
2036	50	100	5	3,364,151							
2037	50	100	5	3,364,151							
2038	50	100	5	3,364,151							
2039	50	100	5	3,364,151							
2040	50	100	5	3,364,151							
2041	50	100	5	3,364,151							
2042	50	100	5	3,364,151							
2043	50	100	5	3,364,151							

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual Customer Benefits Indicators (CBIs) over the study period under Reference Case assumptions

UM 2225 Order Summary/Rubric references: C.4(b)

16 Portfolio16

Year	CBRE Solar (pCBI)	CBRE Micro (pCBI)	CBRE Hydrc (pCBI)	rCBI (2023$)	CBI 5 (units)	CBI 6 (units)	CBI 7 (units)	CBI 8 (units)	CBI 9 (units)	CBI 10 (units)	…
2023	0	0	0	-							
2024	0	0	0	-							
2025	0	0	0	-							
2026	22	43	1	1,431,766							
2027	28	56	1	1,843,632							
2028	36	71	3	2,385,264							
2029	43	85	5	2,883,713							
2030	50	100	5	3,360,679							
2031	50	100	5	3,360,679							
2032	50	100	5	3,360,679							
2033	50	100	5	3,360,679							
2034	50	100	5	3,360,679							
2035	50	100	5	3,360,679							
2036	50	100	5	3,360,896							
2037	50	100	5	3,361,113							
2038	50	100	5	3,361,330							
2039	50	100	5	3,361,547							
2040	50	100	5	3,361,764							
2041	50	100	5	3,361,764							
2042	50	100	5	3,361,764							
2043	50	100	5	3,361,764							

17 Portfolio17

Year	CBRE Solar (pCBI)	CBRE Micro (pCBI)	CBRE Hydrc (pCBI)	rCBI (2023$)	CBI 5 (units)	CBI 6 (units)	CBI 7 (units)	CBI 8 (units)	CBI 9 (units)	CBI 10 (units)	…
2023	0	0	0	-							
2024	0	0	0	-							
2025	0	0	0	-							
2026	22	43	1	1,431,766							
2027	28	56	1	1,843,632							
2028	36	71	3	2,385,264							
2029	43	85	5	2,883,713							
2030	50	100	5	3,360,679							
2031	50	100	5	3,360,679							
2032	50	100	5	3,360,679							
2033	50	100	5	3,360,679							
2034	50	100	5	3,360,679							
2035	50	100	5	3,360,679							
2036	50	100	5	3,360,896							
2037	50	100	5	3,361,113							
2038	50	100	5	3,361,330							
2039	50	100	5	3,361,547							
2040	50	100	5	3,361,547							
2041	50	100	5	3,361,547							
2042	50	100	5	3,361,547							
2043	50	100	5	3,361,547							

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual Customer Benefits Indicators (CBIs) over the study period under Reference Case assumptions

UM 2225 Order Summary/Rubric references: C.4(b)

18 Portfolio18

Year	CBRE Solar (pCBI)	CBRE Micro (pCBI)	CBRE Hydrc (pCBI)	rCBI (2023$)	CBI 5 (units)	CBI 6 (units)	CBI 7 (units)	CBI 8 (units)	CBI 9 (units)	CBI 10 (units)	...
2023	0	0	0	-							
2024	0	0	0	-							
2025	0	0	0	-							
2026	22	43	1	1,432,417							
2027	28	56	1	1,844,283							
2028	36	71	3	2,386,132							
2029	43	85	5	2,885,666							
2030	50	100	5	3,363,717							
2031	50	100	5	3,363,934							
2032	50	100	5	3,364,151							
2033	50	100	5	3,364,151							
2034	50	100	5	3,364,151							
2035	50	100	5	3,364,151							
2036	50	100	5	3,364,151							
2037	50	100	5	3,364,151							
2038	50	100	5	3,364,151							
2039	50	100	5	3,364,151							
2040	50	100	5	3,364,151							
2041	50	100	5	3,364,151							
2042	50	100	5	3,364,151							
2043	50	100	5	3,364,151							

19 Portfolio19

Year	CBRE Solar (pCBI)	CBRE Micro (pCBI)	CBRE Hydrc (pCBI)	rCBI (2023$)	CBI 5 (units)	CBI 6 (units)	CBI 7 (units)	CBI 8 (units)	CBI 9 (units)	CBI 10 (units)	...
2023	0	0	0	-							
2024	0	0	0	-							
2025	0	0	0	-							
2026	22	43	1	1,432,200							
2027	28	56	1	1,844,500							
2028	36	71	3	2,387,217							
2029	43	85	5	2,886,100							
2030	50	100	5	3,363,717							
2031	50	100	5	3,363,934							
2032	50	100	5	3,364,151							
2033	50	100	5	3,364,151							
2034	50	100	5	3,364,151							
2035	50	100	5	3,364,151							
2036	50	100	5	3,364,151							
2037	50	100	5	3,364,151							
2038	50	100	5	3,364,151							
2039	50	100	5	3,364,151							
2040	50	100	5	3,364,151							
2041	50	100	5	3,364,151							
2042	50	100	5	3,364,151							
2043	50	100	5	3,364,151							

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual Customer Benefits Indicators (CBIs) over the study period under Reference Case assumptions

UM 2225 Order Summary/Rubric references: C.4(b)

20 Portfolio20

Year	CBRE Solar (pCBI)	CBRE Micro (pCBI)	CBRE Hydrc (pCBI)	rCBI (2023$)	CBI 5 (units)	CBI 6 (units)	CBI 7 (units)	CBI 8 (units)	CBI 9 (units)	CBI 10 (units)	…
2023	0	0	0	-							
2024	0	0	0	-							
2025	0	0	0	-							
2026	22	43	1	1,431,766							
2027	28	56	1	1,843,632							
2028	36	71	3	2,385,915							
2029	43	85	5	2,885,666							
2030	50	100	5	3,363,717							
2031	50	100	5	3,363,934							
2032	50	100	5	3,364,151							
2033	50	100	5	3,364,151							
2034	50	100	5	3,364,151							
2035	50	100	5	3,364,151							
2036	50	100	5	3,364,151							
2037	50	100	5	3,364,151							
2038	50	100	5	3,364,151							
2039	50	100	5	3,364,151							
2040	50	100	5	3,364,151							
2041	50	100	5	3,364,151							
2042	50	100	5	3,364,151							
2043	50	100	5	3,364,151							

21 Portfolio21

Year	CBRE Solar (pCBI)	CBRE Micro (pCBI)	CBRE Hydrc (pCBI)	rCBI (2023$)	CBI 5 (units)	CBI 6 (units)	CBI 7 (units)	CBI 8 (units)	CBI 9 (units)	CBI 10 (units)	…
2023	0	0	0	-							
2024	0	0	0	-							
2025	0	0	0	-							
2026	22	43	1	1,431,766							
2027	28	56	1	1,843,632							
2028	36	71	3	2,385,481							
2029	43	85	5	2,885,232							
2030	50	100	5	3,363,283							
2031	50	100	5	3,363,934							
2032	50	100	5	3,364,151							
2033	50	100	5	3,364,151							
2034	50	100	5	3,364,151							
2035	50	100	5	3,364,151							
2036	50	100	5	3,364,151							
2037	50	100	5	3,364,151							
2038	50	100	5	3,364,151							
2039	50	100	5	3,364,151							
2040	50	100	5	3,364,151							
2041	50	100	5	3,364,151							
2042	50	100	5	3,364,151							
2043	50	100	5	3,364,151							

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual Customer Benefits Indicators (CBIs) over the study period under Reference Case assumptions

UM 2225 Order Summary/Rubric references: C.4(b)

22 Portfolio22

Year	CBRE Solar (pCBI)	CBRE Micro (pCBI)	CBRE Hydrc (pCBI)	rCBI (2023$)	CBI 5 (units)	CBI 6 (units)	CBI 7 (units)	CBI 8 (units)	CBI 9 (units)	CBI 10 (units)	…
2023	0	0	0	-							
2024	0	0	0	-							
2025	0	0	0	-							
2026	22	43	1	1,432,200							
2027	28	56	1	1,844,500							
2028	36	71	3	2,386,349							
2029	43	85	5	2,885,666							
2030	50	100	5	3,363,717							
2031	50	100	5	3,363,934							
2032	50	100	5	3,364,151							
2033	50	100	5	3,364,151							
2034	50	100	5	3,364,151							
2035	50	100	5	3,364,151							
2036	50	100	5	3,364,151							
2037	50	100	5	3,364,151							
2038	50	100	5	3,364,151							
2039	50	100	5	3,364,151							
2040	50	100	5	3,364,151							
2041	50	100	5	3,364,151							
2042	50	100	5	3,364,151							
2043	50	100	5	3,364,151							

23 Portfolio23

Year	CBRE Solar (pCBI)	CBRE Micro (pCBI)	CBRE Hydrc (pCBI)	rCBI (2023$)	CBI 5 (units)	CBI 6 (units)	CBI 7 (units)	CBI 8 (units)	CBI 9 (units)	CBI 10 (units)	…
2023	0	0	0	-							
2024	0	0	0	-							
2025	0	0	0	-							
2026	22	43	1	1,432,417							
2027	28	56	1	1,844,717							
2028	36	71	3	2,386,349							
2029	43	85	5	2,885,666							
2030	50	100	5	3,363,500							
2031	50	100	5	3,363,934							
2032	50	100	5	3,364,151							
2033	50	100	5	3,364,151							
2034	50	100	5	3,364,151							
2035	50	100	5	3,364,151							
2036	50	100	5	3,364,151							
2037	50	100	5	3,364,151							
2038	50	100	5	3,364,151							
2039	50	100	5	3,364,151							
2040	50	100	5	3,364,151							
2041	50	100	5	3,364,151							
2042	50	100	5	3,364,151							
2043	50	100	5	3,364,151							

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual Customer Benefits Indicators (CBIs) over the study period under Reference Case assumptions

UM 2225 Order Summary/Rubric references: C.4(b)

24 Portfolio24

Year	CBRE Solar (pCBI)	CBRE Micro (pCBI)	CBRE Hydrc (pCBI)	rCBI (2023$)	CBI 5 (units)	CBI 6 (units)	CBI 7 (units)	CBI 8 (units)	CBI 9 (units)	CBI 10 (units)	...
2023	0	0	0	-							
2024	0	0	0	-							
2025	0	0	0	-							
2026	22	43	1	1,431,766							
2027	28	56	1	1,843,632							
2028	36	71	3	2,385,915							
2029	43	85	5	2,885,666							
2030	50	100	5	3,363,717							
2031	50	100	5	3,363,934							
2032	50	100	5	3,364,151							
2033	50	100	5	3,364,151							
2034	50	100	5	3,364,151							
2035	50	100	5	3,364,151							
2036	50	100	5	3,364,151							
2037	50	100	5	3,364,151							
2038	50	100	5	3,364,151							
2039	50	100	5	3,364,151							
2040	50	100	5	3,364,151							
2041	50	100	5	3,364,151							
2042	50	100	5	3,364,151							
2043	50	100	5	3,364,151							

25 Portfolio25

Year	CBRE Solar (pCBI)	CBRE Micro (pCBI)	CBRE Hydrc (pCBI)	rCBI (2023$)	CBI 5 (units)	CBI 6 (units)	CBI 7 (units)	CBI 8 (units)	CBI 9 (units)	CBI 10 (units)	...
2023	0	0	0	-							
2024	0	0	0	-							
2025	0	0	0	-							
2026	22	43	1	1,432,200							
2027	28	56	1	1,844,066							
2028	36	71	3	2,385,915							
2029	43	85	5	2,885,666							
2030	50	100	5	3,363,717							
2031	50	100	5	3,363,934							
2032	50	100	5	3,364,151							
2033	50	100	5	3,364,151							
2034	50	100	5	3,364,151							
2035	50	100	5	3,364,151							
2036	50	100	5	3,364,151							
2037	50	100	5	3,364,151							
2038	50	100	5	3,364,151							
2039	50	100	5	3,364,151							
2040	50	100	5	3,364,151							
2041	50	100	5	3,364,151							
2042	50	100	5	3,364,151							
2043	50	100	5	3,364,151							

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual Customer Benefits Indicators (CBIs) over the study period under Reference Case assumptions

UM 2225 Order Summary/Rubric references: C.4(b)

26 Portfolio26

Year	CBRE Solar (pCBI)	CBRE Micro (pCBI)	CBRE Hydrc (pCBI)	rCBI (2023$)	CBI 5 (units)	CBI 6 (units)	CBI 7 (units)	CBI 8 (units)	CBI 9 (units)	CBI 10 (units)	...
2023	0	0	0	-							
2024	0	0	0	-							
2025	0	0	0	-							
2026	22	43	1	1,432,200							
2027	28	56	1	1,844,066							
2028	36	71	3	2,385,698							
2029	43	85	5	2,885,449							
2030	50	100	5	3,363,500							
2031	50	100	5	3,363,934							
2032	50	100	5	3,364,151							
2033	50	100	5	3,364,151							
2034	50	100	5	3,364,151							
2035	50	100	5	3,364,151							
2036	50	100	5	3,364,151							
2037	50	100	5	3,364,151							
2038	50	100	5	3,364,151							
2039	50	100	5	3,364,151							
2040	50	100	5	3,364,151							
2041	50	100	5	3,364,151							
2042	50	100	5	3,364,151							
2043	50	100	5	3,364,151							

27 Portfolio27

Year	CBRE Solar (pCBI)	CBRE Micro (pCBI)	CBRE Hydrc (pCBI)	rCBI (2023$)	CBI 5 (units)	CBI 6 (units)	CBI 7 (units)	CBI 8 (units)	CBI 9 (units)	CBI 10 (units)	...
2023	0	0	0	-							
2024	0	0	0	-							
2025	0	0	0	-							
2026	22	43	1	1,432,200							
2027	28	56	1	1,844,066							
2028	36	71	3	2,385,915							
2029	43	85	5	2,885,666							
2030	50	100	5	3,363,717							
2031	50	100	5	3,363,934							
2032	50	100	5	3,364,151							
2033	50	100	5	3,364,151							
2034	50	100	5	3,364,151							
2035	50	100	5	3,364,151							
2036	50	100	5	3,364,151							
2037	50	100	5	3,364,151							
2038	50	100	5	3,364,151							
2039	50	100	5	3,364,151							
2040	50	100	5	3,364,151							
2041	50	100	5	3,364,151							
2042	50	100	5	3,364,151							
2043	50	100	5	3,364,151							

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual Customer Benefits Indicators (CBIs) over the study period under Reference Case assumptions

UM 2225 Order Summary/Rubric references: C.4(b)

28 Portfolio28

Year	CBRE Solar (pCBI)	CBRE Micro (pCBI)	CBRE Hydrc (pCBI)	rCBI (2023$)	CBI 5 (units)	CBI 6 (units)	CBI 7 (units)	CBI 8 (units)	CBI 9 (units)	CBI 10 (units)	...
2023	0	0	0	-							
2024	0	0	0	-							
2025	0	0	0	-							
2026	22	43	1	1,432,200							
2027	28	56	1	1,844,066							
2028	36	71	3	2,386,132							
2029	43	85	5	2,885,883							
2030	50	100	5	3,363,934							
2031	50	100	5	3,364,151							
2032	50	100	5	3,364,151							
2033	50	100	5	3,364,151							
2034	50	100	5	3,364,151							
2035	50	100	5	3,364,151							
2036	50	100	5	3,364,151							
2037	50	100	5	3,364,151							
2038	50	100	5	3,364,151							
2039	50	100	5	3,364,151							
2040	50	100	5	3,364,151							
2041	50	100	5	3,364,151							
2042	50	100	5	3,364,151							
2043	50	100	5	3,364,151							

29 Portfolio29

Year	CBRE Solar (pCBI)	CBRE Micro (pCBI)	CBRE Hydrc (pCBI)	rCBI (2023$)	CBI 5 (units)	CBI 6 (units)	CBI 7 (units)	CBI 8 (units)	CBI 9 (units)	CBI 10 (units)	...
2023	0	0	0	-							
2024	0	0	0	-							
2025	0	0	0	-							
2026	22	43	1	1,432,200							
2027	28	56	1	1,844,066							
2028	36	71	3	2,385,915							
2029	43	85	5	2,885,666							
2030	50	100	5	3,363,717							
2031	50	100	5	3,363,934							
2032	50	100	5	3,364,151							
2033	50	100	5	3,364,151							
2034	50	100	5	3,364,151							
2035	50	100	5	3,364,151							
2036	50	100	5	3,364,151							
2037	50	100	5	3,364,151							
2038	50	100	5	3,364,151							
2039	50	100	5	3,364,151							
2040	50	100	5	3,364,151							
2041	50	100	5	3,364,151							
2042	50	100	5	3,364,151							
2043	50	100	5	3,364,151							

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual Customer Benefits Indicators (CBIs) over the study period under Reference Case assumptions

UM 2225 Order Summary/Rubric references: C.4(b)

30 Portfolio30

Year	CBRE Solar (pCBI)	CBRE Micro (pCBI)	CBRE Hydrc (pCBI)	rCBI (2023$)	CBI 5 (units)	CBI 6 (units)	CBI 7 (units)	CBI 8 (units)	CBI 9 (units)	CBI 10 (units)	…
2023	0	0	0	-							
2024	0	0	0	-							
2025	0	0	0	-							
2026	22	43	1	1,432,200							
2027	28	56	1	1,844,066							
2028	36	71	3	2,385,698							
2029	43	85	5	2,885,449							
2030	50	100	5	3,363,500							
2031	50	100	5	3,363,934							
2032	50	100	5	3,364,151							
2033	50	100	5	3,364,151							
2034	50	100	5	3,364,151							
2035	50	100	5	3,364,151							
2036	50	100	5	3,364,151							
2037	50	100	5	3,364,151							
2038	50	100	5	3,364,151							
2039	50	100	5	3,364,151							
2040	50	100	5	3,364,151							
2041	50	100	5	3,364,151							
2042	50	100	5	3,364,151							
2043	50	100	5	3,364,151							

31 Portfolio31

Year	CBRE Solar (pCBI)	CBRE Micro (pCBI)	CBRE Hydrc (pCBI)	rCBI (2023$)	CBI 5 (units)	CBI 6 (units)	CBI 7 (units)	CBI 8 (units)	CBI 9 (units)	CBI 10 (units)	…
2023	0	0	0	-							
2024	0	0	0	-							
2025	0	0	0	-							
2026	22	43	1	1,432,200							
2027	28	56	1	1,844,066							
2028	36	71	3	2,385,915							
2029	43	85	5	2,885,666							
2030	50	100	5	3,363,717							
2031	50	100	5	3,363,934							
2032	50	100	5	3,364,151							
2033	50	100	5	3,364,151							
2034	50	100	5	3,364,151							
2035	50	100	5	3,364,151							
2036	50	100	5	3,364,151							
2037	50	100	5	3,364,151							
2038	50	100	5	3,364,151							
2039	50	100	5	3,364,151							
2040	50	100	5	3,364,151							
2041	50	100	5	3,364,151							
2042	50	100	5	3,364,151							
2043	50	100	5	3,364,151							

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual Customer Benefits Indicators (CBIs) over the study period under Reference Case assumptions

UM 2225 Order Summary/Rubric references: C.4(b)

32 Portfolio32

Year	CBRE Solar (pCBI)	CBRE Micro (pCBI)	CBRE Hydrc (pCBI)	rCBI (2023$)	CBI 5 (units)	CBI 6 (units)	CBI 7 (units)	CBI 8 (units)	CBI 9 (units)	CBI 10 (units)	…
2023	0	0	0	-							
2024	0	0	0	-							
2025	0	0	0	-							
2026	22	43	1	1,432,200							
2027	28	56	1	1,844,066							
2028	36	71	3	2,385,915							
2029	43	85	5	2,885,666							
2030	50	100	5	3,363,717							
2031	50	100	5	3,363,934							
2032	50	100	5	3,364,151							
2033	50	100	5	3,364,151							
2034	50	100	5	3,364,151							
2035	50	100	5	3,364,151							
2036	50	100	5	3,364,151							
2037	50	100	5	3,364,151							
2038	50	100	5	3,364,151							
2039	50	100	5	3,364,151							
2040	50	100	5	3,364,151							
2041	50	100	5	3,364,151							
2042	50	100	5	3,364,151							
2043	50	100	5	3,364,151							

33 Portfolio33

Year	CBRE Solar (pCBI)	CBRE Micro (pCBI)	CBRE Hydrc (pCBI)	rCBI (2023$)	CBI 5 (units)	CBI 6 (units)	CBI 7 (units)	CBI 8 (units)	CBI 9 (units)	CBI 10 (units)	…
2023	0	0	0	-							
2024	0	0	0	-							
2025	0	0	0	-							
2026	22	43	1	1,431,766							
2027	28	56	1	1,843,632							
2028	36	71	3	2,385,915							
2029	43	85	5	2,885,666							
2030	50	100	5	3,363,717							
2031	50	100	5	3,363,717							
2032	50	100	5	3,363,717							
2033	50	100	5	3,363,717							
2034	50	100	5	3,363,717							
2035	50	100	5	3,363,717							
2036	50	100	5	3,363,717							
2037	50	100	5	3,363,717							
2038	50	100	5	3,363,717							
2039	50	100	5	3,363,717							
2040	50	100	5	3,363,717							
2041	50	100	5	3,363,934							
2042	50	100	5	3,363,934							
2043	50	100	5	3,364,151							

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual Customer Benefits Indicators (CBIs) over the study period under Reference Case assumptions

UM 2225 Order Summary/Rubric references: C.4(b)

34 Portfolio34

Year	CBRE Solar (pCBI)	CBRE Micro (pCBI)	CBRE Hydrc (pCBI)	rCBI (2023$)	CBI 5 (units)	CBI 6 (units)	CBI 7 (units)	CBI 8 (units)	CBI 9 (units)	CBI 10 (units)	...
2023	0	0	0	-							
2024	0	0	0	-							
2025	0	0	0	-							
2026	22	43	1	1,431,766							
2027	28	56	1	1,843,632							
2028	36	71	3	2,385,915							
2029	43	85	5	2,885,666							
2030	50	100	5	3,363,717							
2031	50	100	5	3,363,717							
2032	50	100	5	3,363,717							
2033	50	100	5	3,363,717							
2034	50	100	5	3,363,717							
2035	50	100	5	3,363,717							
2036	50	100	5	3,363,717							
2037	50	100	5	3,363,934							
2038	50	100	5	3,363,934							
2039	50	100	5	3,363,934							
2040	50	100	5	3,363,934							
2041	50	100	5	3,363,934							
2042	50	100	5	3,363,934							
2043	50	100	5	3,364,151							

35 Portfolio35

Year	CBRE Solar (pCBI)	CBRE Micro (pCBI)	CBRE Hydrc (pCBI)	rCBI (2023$)	CBI 5 (units)	CBI 6 (units)	CBI 7 (units)	CBI 8 (units)	CBI 9 (units)	CBI 10 (units)	...
2023	0	0	0	-							
2024	0	0	0	-							
2025	0	0	0	-							
2026	22	43	1	1,432,417							
2027	28	56	1	1,844,283							
2028	36	71	3	2,385,915							
2029	43	85	5	2,885,015							
2030	50	100	5	3,363,066							
2031	50	100	5	3,363,500							
2032	50	100	5	3,363,934							
2033	50	100	5	3,364,151							
2034	50	100	5	3,364,151							
2035	50	100	5	3,364,151							
2036	50	100	5	3,364,151							
2037	50	100	5	3,364,151							
2038	50	100	5	3,364,151							
2039	50	100	5	3,364,151							
2040	50	100	5	3,364,151							
2041	50	100	5	3,364,151							
2042	50	100	5	3,364,151							
2043	50	100	5	3,364,151							

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual Customer Benefits Indicators (CBIs) over the study period under Reference Case assumptions

UM 2225 Order Summary/Rubric references: C.4(b)

36 Portfolio36

Year	CBRE Solar (pCBI)	CBRE Micro (pCBI)	CBRE Hydrc (pCBI)	rCBI (2023$)	CBI 5 (units)	CBI 6 (units)	CBI 7 (units)	CBI 8 (units)	CBI 9 (units)	CBI 10 (units)	...
2023	0	0	0	-							
2024	0	0	0	-							
2025	0	0	0	-							
2026	22	43	1	1,432,417							
2027	28	56	1	1,844,283							
2028	36	71	3	2,385,915							
2029	43	85	5	2,885,232							
2030	50	100	5	3,363,283							
2031	50	100	5	3,363,934							
2032	50	100	5	3,364,151							
2033	50	100	5	3,364,151							
2034	50	100	5	3,364,151							
2035	50	100	5	3,364,151							
2036	50	100	5	3,364,151							
2037	50	100	5	3,364,151							
2038	50	100	5	3,364,151							
2039	50	100	5	3,364,151							
2040	50	100	5	3,364,151							
2041	50	100	5	3,364,151							
2042	50	100	5	3,364,151							
2043	50	100	5	3,364,151							

37 Portfolio37

Year	CBRE Solar (pCBI)	CBRE Micro (pCBI)	CBRE Hydrc (pCBI)	rCBI (2023$)	CBI 5 (units)	CBI 6 (units)	CBI 7 (units)	CBI 8 (units)	CBI 9 (units)	CBI 10 (units)	...
2023	0	0	0	-							
2024	0	0	0	-							
2025	0	0	0	-							
2026	22	43	1	1,432,417							
2027	28	56	1	1,844,283							
2028	36	71	3	2,386,132							
2029	43	85	5	2,885,666							
2030	50	100	5	3,363,717							
2031	50	100	5	3,363,934							
2032	50	100	5	3,364,151							
2033	50	100	5	3,364,151							
2034	50	100	5	3,364,151							
2035	50	100	5	3,364,151							
2036	50	100	5	3,364,151							
2037	50	100	5	3,364,151							
2038	50	100	5	3,364,151							
2039	50	100	5	3,364,151							
2040	50	100	5	3,364,151							
2041	50	100	5	3,364,151							
2042	50	100	5	3,364,151							
2043	50	100	5	3,364,151							

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the annual Customer Benefits Indicators (CBIs) over the study period under Reference Case assumptions

UM 2225 Order Summary/Rubric references: C.4(b)

38 Portfolio38

Year	CBRE Solar (pCBI)	CBRE Micro (pCBI)	CBRE Hydrc (pCBI)	rCBI (2023$)	CBI 5 (units)	CBI 6 (units)	CBI 7 (units)	CBI 8 (units)	CBI 9 (units)	CBI 10 (units)	…
2023	0	0	0	-							
2024	0	0	0	-							
2025	0	0	0	-							
2026	22	43	1	1,432,417							
2027	28	56	1	1,844,283							
2028	36	71	3	2,385,915							
2029	43	85	5	2,885,232							
2030	50	100	5	3,363,283							
2031	50	100	5	3,363,934							
2032	50	100	5	3,364,151							
2033	50	100	5	3,364,151							
2034	50	100	5	3,364,151							
2035	50	100	5	3,364,151							
2036	50	100	5	3,364,151							
2037	50	100	5	3,364,151							
2038	50	100	5	3,364,151							
2039	50	100	5	3,364,151							
2040	50	100	5	3,364,151							
2041	50	100	5	3,364,151							
2042	50	100	5	3,364,151							
2043	50	100	5	3,364,151							

39 Portfolio39

Year	CBRE Solar (pCBI)	CBRE Micro (pCBI)	CBRE Hydrc (pCBI)	rCBI (2023$)	CBI 5 (units)	CBI 6 (units)	CBI 7 (units)	CBI 8 (units)	CBI 9 (units)	CBI 10 (units)	…
2023	0	0	0	-							
2024	0	0	0	-							
2025	0	0	0	-							
2026	22	43	1	1,430,247							
2027	28	56	1	1,841,462							
2028	36	71	3	2,383,311							
2029	43	85	5	2,883,062							
2030	50	100	5	3,361,113							
2031	50	100	5	3,361,764							
2032	50	100	5	3,362,415							
2033	50	100	5	3,362,849							
2034	50	100	5	3,363,283							
2035	50	100	5	3,363,500							
2036	50	100	5	3,363,717							
2037	50	100	5	3,363,934							
2038	50	100	5	3,364,151							
2039	50	100	5	3,364,151							
2040	50	100	5	3,364,151							
2041	50	100	5	3,364,151							
2042	50	100	5	3,364,151							
2043	50	100	5	3,364,151							

Instructions

For each of the portfolios listed on the "Portfolios" tab, list the scoring metrics for cost, risk, GHG emissions reductions, and community benefits and impacts used to select the Preferred Portfolio and design the Action Plan

UM 2225 Order Summary/Rubric references: B.1

	Portfolio	Cost - NPVRR (million 2023$)	Risk metric - Variability (million 2023$)	Risk metric - Severity (million 2023$)	GHG Reductions Metric(s) (metric ton)	Community Impacts Metric(s) (CBRE MW)	… (units)
1	Portfolio1	$ 42,041.68	$ 12,087.37	$ 58,511.15	38,494,254	155	
2	Portfolio2	$ 42,772.21	$ 12,227.34	$ 59,418.70	34,511,484	155	
3	Portfolio3	$ 41,611.73	$ 11,995.71	$ 57,976.33	42,477,023	155	
4	Portfolio4	$ 43,138.75	$ 11,843.40	$ 59,302.57	34,444,254	155	
5	Portfolio5	$ 43,777.14	$ 12,065.78	$ 60,222.24	31,824,647	155	
6	Portfolio6	$ 41,480.76	$ 12,251.42	$ 58,298.25	38,494,254	155	
7	Portfolio7	$ 42,041.68	$ 12,325.77	$ 58,686.47	38,494,254	155	
8	Portfolio8	$ 41,657.14	$ 12,257.60	$ 58,665.65	38,494,254	155	
9	Portfolio9	$ 42,041.68	$ 12,325.77	$ 58,686.47	38,494,254	155	
10	Portfolio10	$ 42,142.68	$ 12,321.95	$ 58,746.24	38,494,254	117	
11	Portfolio11	$ 42,457.33	$ 12,075.20	$ 58,762.76	38,494,254	0	
12	Portfolio12	$ 42,160.67	$ 12,335.17	$ 58,789.13	38,494,254	100	
13	Portfolio13	$ 42,041.67	$ 12,325.33	$ 58,685.80	38,494,254	155	
14	Portfolio14	$ 20,268.65	$ 4,827.33	$ 28,407.09	38,494,254	0	
15	Portfolio15	$ 45,594.59	$ 12,679.45	$ 62,539.33	38,494,254	155	
16	Portfolio16	$ 20,741.09	$ 5,107.50	$ 29,397.03	38,494,254	155	
17	Portfolio17	$ 20,190.84	$ 5,097.96	$ 28,950.73	38,494,254	155	
18	Portfolio18	$ 42,044.77	$ 12,322.36	$ 58,685.12	38,494,254	155	
19	Portfolio19	$ 42,302.47	$ 12,547.93	$ 59,211.49	38,494,254	155	
20	Portfolio20	$ 42,999.14	$ 12,199.48	$ 59,853.74	38,494,254	155	
21	Portfolio21	$ 43,734.37	$ 12,194.65	$ 60,615.46	38,494,254	155	
22	Portfolio22	$ 42,830.95	$ 12,395.13	$ 59,930.02	38,494,254	155	
23	Portfolio23	$ 43,491.53	$ 12,377.91	$ 60,668.57	38,494,254	155	
24	Portfolio24	$ 42,257.73	$ 12,382.60	$ 58,974.99	38,494,254	155	
25	Portfolio25	$ 42,041.68	$ 12,325.77	$ 58,686.47	38,494,254	155	
26	Portfolio26	$ 41,065.06	$ 12,638.89	$ 58,207.24	38,494,254	155	
27	Portfolio27	$ 41,730.82	$ 12,207.37	$ 58,386.48	38,494,254	155	
28	Portfolio28	$ 38,996.37	$ 12,209.95	$ 55,830.12	38,494,254	155	
29	Portfolio29	$ 42,055.95	$ 12,262.64	$ 58,965.39	38,494,254	155	
30	Portfolio30	$ 41,792.65	$ 12,155.78	$ 58,344.29	38,494,254	155	
31	Portfolio31	$ 41,128.05	$ 12,324.63	$ 57,771.69	38,494,254	155	
32	Portfolio32	$ 42,041.68	$ 12,325.77	$ 58,686.47	38,494,254	155	
33	Portfolio33				38,494,254	155	
34	Portfolio34				38,494,254	155	
35	Portfolio35	$ 37,699.67	$ 11,560.71	$ 54,186.10	38,494,254	155	
36	Portfolio36	$ 41,503.09	$ 12,043.61	$ 58,155.46	38,494,254	155	
37	Portfolio37	$ 41,702.62	$ 12,059.20	$ 58,228.60	38,494,254	155	
38	Portfolio38	$ 42,199.03	$ 12,044.97	$ 59,374.25	38,494,254	155	
39	Portfolio39	$ 37,225.82	$ 11,523.72	$ 53,865.79	38,494,254	155	
40	Portfolio40	$ 36,955.54	$ 11,875.92	$ 53,918.29	38,494,254	155	
	sources:	Preferred portfolio summary: NPVRR	Preferred portfolio summary: semi-deviation	Preferred portfolio summary: tail VAR90	Sum of retail carbon from 2023-2043	Max of CBRE capacity between 2023-2043	

Note: the cost and risk metrics for near-term optimization portfolios are not comparable to other portfolios and accordingly have been omitted

GHG Emissions Assumptions

Provide the GHG emissions assumptions for each existing and proxy resource modeled in the IRP, developed in partnership with DEQ

UM 2225 Order Summary/Rubric references: J.3(a)

For market purchases the DEQ specifies a 2% line loss adjustment (not included below)

	Beaver	Carty	Coyote	PW1	PW2	Colstrip (20% PGE s	Market gas	Market waste	Market ACS	Market_unspec	Fossil fuel resource	Fossil fuel reso	Fossil fuel reso	Fossil fuel reso	Fossil fuel reso	Fossil fuel reso	Fossil fuel reso	Fossil fuel reso	Fossil fuel reso	Fossil fuel reso	Fossil fuel reso	...
GHG Emissions Rate (	0.54	0.39	0.38	0.38	0.51	1.00	0.41	1.32	0.01	0.43												
sources:	DEQ; 12.20.22 (GHG model_linear decline, unit intensity and run ratios)	DEQ; 12.20.22 (GHG model_linear decline, unit intensity and run ratios)	DEQ; 12.20.22 (GHG model_linear decline, unit intensity and run ratios)	DEQ; 12.20.22 (GHG model_linear decline, unit intensity and run ratios)	DEQ; 12.20.22 (GHG model_linear decline, unit intensity and run ratios)	DEQ; 12.20.22 (GHG model_linear decline, unit intensity and run ratios)	DEQ; 12.20.22 (GHG model_linear decline, unit intensity and run ratios)	DEQ; 12.20.22 (GHG model_linear decline, unit intensity and run ratios)	DEQ; 12.20.22 (GHG model_linear decline, unit intensity and run ratios)	DEQ; 12.20.22 (GHG model_linear decline, unit intensity and run ratios)												

GHG emissions by resource

Provide the cumulative forecasted GHG emissions from each existing and proxy resource in the Preferred Portfolio under the Reference Case over the entire analysis horizon (at least 20 years) and the location of each emitting resource

UM 2225 Order Summary/Rubric references: J.3(b)

Portfolio40 Retail emissions

	Beaver	Carty	Coyote	PW1	PW2	Colstrip (20% PGE s	Market gas	Market waste	Market ACS	Market_unspec	Fossil fuel resource	Fossil fuel reso	Fossil fuel reso	Fossil fuel reso	Fossil fuel reso	Fossil fuel reso	Fossil fuel reso	Fossil fuel reso	Fossil fuel reso	Fossil fuel reso	Fossil fuel reso	...
Cumulative GHG Emi	3,009,358	6,261,804	3,438,524	4,881,624	1,782,328	6,442,582	35,462	41,846	74,363	12,526,364												
Location (lat, long)	46.17°, -123.17°	45.69°, -119.81°	45.84°, -119.67°	46.17°,-123.17°	46.17°,-123.17°	45.88°,-106.61°	NA	NA	NA	NA												
sources:	GHG model_linear decline: sum of GHG emissions forecast 2023-43	GHG model_linear decline: sum of GHG emissions forecast 2023-43	GHG model_linear decline: sum of GHG emissions forecast 2023-43	GHG model_linear decline: sum of GHG emissions forecast 2023-43	GHG model_linear decline: sum of GHG emissions forecast 2023-43	GHG model_linear decline: sum of GHG emissions forecast 2023-43	GHG model_linear decline: sum of GHG emissions forecast 2023-43	GHG model_linear decline: sum of GHG emissions forecast 2023-43	GHG model_linear decline: sum of GHG emissions forecast 2023-43	GHG model_linear decline: sum of GHG emissions forecast 2023-43												

Portfolio GHG emissions

For each of the portfolios listed on the "Portfolios" tab, list the annual GHG emissions based on the DEQ methodology over the study period under Reference Case assumptions

Provide at least three years of historical GHG emissions based on the DEQ methodology in column B

UM 2225 Order Summary/Rubric references: J.3(c)

PGE Note: Historical GHG values may differ slightly than official DEQ values. This is due to HB 2021 excluding GHG emissions associated with PURPA resources.

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40
Year	Portfolio1	Portfolio2	Portfolio3	Portfolio4	Portfolio5	Portfolio6	Portfolio7	Portfolio8	Portfolio9	Portfolio10	Portfolio11	Portfolio12	Portfolio13	Portfolio14	Portfolio15	Portfolio16	Portfolio17	Portfolio18	Portfolio19	Portfolio20	Portfolio21	Portfolio22	Portfolio23	Portfolio24	Portfolio25	Portfolio26	Portfolio27	Portfolio28	Portfolio29	Portfolio30	Portfolio31	Portfolio32	Portfolio33	Portfolio34	Portfolio35	Portfolio36	Portfolio37	Portfolio38	Portfolio39	Portfolio40
2020	6,631,604	6,631,604	6,631,604	6,631,604	6,631,604	6,631,604	6,631,604	6,631,604	6,631,604	6,631,604	6,631,604	6,631,604	6,631,604	6,631,604	6,631,604	6,631,604	6,631,604	6,631,604	6,631,604	6,631,604	6,631,604	6,631,604	6,631,604	6,631,604	6,631,604	6,631,604	6,631,604	6,631,604	6,631,604	6,631,604	6,631,604	6,631,604	6,631,604	6,631,604	6,631,604	6,631,604	6,631,604	6,631,604	6,631,604	6,631,604
2021	6,115,986	6,115,986	6,115,986	6,115,986	6,115,986	6,115,986	6,115,986	6,115,986	6,115,986	6,115,986	6,115,986	6,115,986	6,115,986	6,115,986	6,115,986	6,115,986	6,115,986	6,115,986	6,115,986	6,115,986	6,115,986	6,115,986	6,115,986	6,115,986	6,115,986	6,115,986	6,115,986	6,115,986	6,115,986	6,115,986	6,115,986	6,115,986	6,115,986	6,115,986	6,115,986	6,115,986	6,115,986	6,115,986	6,115,986	6,115,986
2022 (initial values)	6,061,280	6,061,280	6,061,280	6,061,280	6,061,280	6,061,280	6,061,280	6,061,280	6,061,280	6,061,280	6,061,280	6,061,280	6,061,280	6,061,280	6,061,280	6,061,280	6,061,280	6,061,280	6,061,280	6,061,280	6,061,280	6,061,280	6,061,280	6,061,280	6,061,280	6,061,280	6,061,280	6,061,280	6,061,280	6,061,280	6,061,280	6,061,280	6,061,280	6,061,280	6,061,280	6,061,280	6,061,280	6,061,280	6,061,280	6,061,280
2023	5,887,117	5,887,117	5,887,117	5,887,117	5,887,117	5,887,117	5,887,117	5,887,117	5,887,117	5,887,117	5,887,117	5,887,117	5,887,117	5,887,117	5,887,117	5,887,117	5,887,117	5,887,117	5,887,117	5,887,117	5,887,117	5,887,117	5,887,117	5,887,117	5,887,117	5,887,117	5,887,117	5,887,117	5,887,117	5,887,117	5,887,117	5,887,117	5,887,117	5,887,117	5,887,117	5,887,117	5,887,117	5,887,117	5,887,117	5,887,117
2024	5,308,316	5,308,316	5,308,316	5,308,316	5,308,316	5,308,316	5,308,316	5,308,316	5,308,316	5,308,316	5,308,316	5,308,316	5,308,316	5,308,316	5,308,316	5,308,316	5,308,316	5,308,316	5,308,316	5,308,316	5,308,316	5,308,316	5,308,316	5,308,316	5,308,316	5,308,316	5,308,316	5,308,316	5,308,316	5,308,316	5,308,316	5,308,316	5,308,316	5,308,316	5,308,316	5,308,316	5,308,316	5,308,316	5,308,316	5,308,316	5,308,316
2025	5,049,607	5,049,607	5,049,607	5,049,607	5,049,607	5,049,607	5,049,607	5,049,607	5,049,607	5,049,607	5,049,607	5,049,607	5,049,607	5,049,607	5,049,607	5,049,607	5,049,607	5,049,607	5,049,607	5,049,607	5,049,607	5,049,607	5,049,607	5,049,607	5,049,607	5,049,607	5,049,607	5,049,607	5,049,607	5,049,607	5,049,607	5,049,607	5,049,607	5,049,607	5,049,607	5,049,607	5,049,607	5,049,607	5,049,607	5,049,607
2026	4,363,686	3,279,487	4,938,974	4,363,686	3,906,405	4,363,686	4,363,686	4,363,686	4,363,686	4,363,686	4,363,686	4,363,686	4,363,686	4,363,686	4,363,686	4,363,686	4,363,686	4,363,686	4,363,686	4,363,686	4,363,686	4,363,686	4,363,686	4,363,686	4,363,686	4,363,686	4,363,686	4,363,686	4,363,686	4,363,686	4,363,686	4,363,686	4,363,686	4,363,686	4,363,686	4,363,686	4,363,686	4,363,686	4,363,686	4,363,686
2027	3,677,764	2,394,427	4,717,710	3,677,764	2,763,202	3,677,764	3,677,764	3,677,764	3,677,764	3,677,764	3,677,764	3,677,764	3,677,764	3,677,764	3,677,764	3,677,764	3,677,764	3,677,764	3,677,764	3,677,764	3,677,764	3,677,764	3,677,764	3,677,764	3,677,764	3,677,764	3,677,764	3,677,764	3,677,764	3,677,764	3,677,764	3,677,764	3,677,764	3,677,764	3,677,764	3,677,764	3,677,764	3,677,764	3,677,764	3,677,764
2028	2,991,843	1,951,897	4,275,180	2,991,843	1,620,000	2,991,843	2,991,843	2,991,843	2,991,843	2,991,843	2,991,843	2,991,843	2,991,843	2,991,843	2,991,843	2,991,843	2,991,843	2,991,843	2,991,843	2,991,843	2,991,843	2,991,843	2,991,843	2,991,843	2,991,843	2,991,843	2,991,843	2,991,843	2,991,843	2,991,843	2,991,843	2,991,843	2,991,843	2,991,843	2,991,843	2,991,843	2,991,843	2,991,843	2,991,843	2,991,843
2029	2,305,921	1,730,632	3,390,120	2,305,921	1,458,000	2,305,921	2,305,921	2,305,921	2,305,921	2,305,921	2,305,921	2,305,921	2,305,921	2,305,921	2,305,921	2,305,921	2,305,921	2,305,921	2,305,921	2,305,921	2,305,921	2,305,921	2,305,921	2,305,921	2,305,921	2,305,921	2,305,921	2,305,921	2,305,921	2,305,921	2,305,921	2,305,921	2,305,921	2,305,921	2,305,921	2,305,921	2,305,921	2,305,921	2,305,921	2,305,921
2030	1,620,000	1,620,000	1,620,000	1,620,000	1,296,000	1,620,000	1,620,000	1,620,000	1,620,000	1,620,000	1,620,000	1,620,000	1,620,000	1,620,000	1,620,000	1,620,000	1,620,000	1,620,000	1,620,000	1,620,000	1,620,000	1,620,000	1,620,000	1,620,000	1,620,000	1,620,000	1,620,000	1,620,000	1,620,000	1,620,000	1,620,000	1,620,000	1,620,000	1,620,000	1,620,000	1,620,000	1,620,000	1,620,000	1,620,000	1,620,000
2031	1,458,000	1,458,000	1,458,000	1,296,000	1,134,000	1,458,000	1,458,000	1,458,000	1,458,000	1,458,000	1,458,000	1,458,000	1,458,000	1,458,000	1,458,000	1,458,000	1,458,000	1,458,000	1,458,000	1,458,000	1,458,000	1,458,000	1,458,000	1,458,000	1,458,000	1,458,000	1,458,000	1,458,000	1,458,000	1,458,000	1,458,000	1,458,000	1,458,000	1,458,000	1,458,000	1,458,000	1,458,000	1,458,000	1,458,000	1,458,000
2032	1,296,000	1,296,000	1,296,000	972,000	972,000	1,296,000	1,296,000	1,296,000	1,296,000	1,296,000	1,296,000	1,296,000	1,296,000	1,296,000	1,296,000	1,296,000	1,296,000	1,296,000	1,296,000	1,296,000	1,296,000	1,296,000	1,296,000	1,296,000	1,296,000	1,296,000	1,296,000	1,296,000	1,296,000	1,296,000	1,296,000	1,296,000	1,296,000	1,296,000	1,296,000	1,296,000	1,296,000	1,296,000	1,296,000	1,296,000
2033	1,134,000	1,134,000	1,134,000	648,000	810,000	1,134,000	1,134,000	1,134,000	1,134,000	1,134,000	1,134,000	1,134,000	1,134,000	1,134,000	1,134,000	1,134,000	1,134,000	1,134,000	1,134,000	1,134,000	1,134,000	1,134,000	1,134,000	1,134,000	1,134,000	1,134,000	1,134,000	1,134,000	1,134,000	1,134,000	1,134,000	1,134,000	1,134,000	1,134,000	1,134,000	1,134,000	1,134,000	1,134,000	1,134,000	1,134,000
2034	972,000	972,000	972,000	324,000	648,000	972,000	972,000	972,000	972,000	972,000	972,000	972,000	972,000	972,000	972,000	972,000	972,000	972,000	972,000	972,000	972,000	972,000	972,000	972,000	972,000	972,000	972,000	972,000	972,000	972,000	972,000	972,000	972,000	972,000	972,000	972,000	972,000	972,000	972,000
2035	810,000	810,000	810,000	-	486,000	810,000	810,000	810,000	810,000	810,000	810,000	810,000	810,000	810,000	810,000	810,000	810,000	810,000	810,000	810,000	810,000	810,000	810,000	810,000	810,000	810,000	810,000	810,000	810,000	810,000	810,000	810,000	810,000	810,000	810,000	810,000	810,000	810,000	810,000
2036	648,000	648,000	648,000	-	324,000	648,000	648,000	648,000	648,000	648,000	648,000	648,000	648,000	648,000	648,000	648,000	648,000	648,000	648,000	648,000	648,000	648,000	648,000	648,000	648,000	648,000	648,000	648,000	648,000	648,000	648,000	648,000	648,000	648,000	648,000	648,000	648,000	648,000	648,000
2037	486,000	486,000	486,000	-	162,000	486,000	486,000	486,000	486,000	486,000	486,000	486,000	486,000	486,000	486,000	486,000	486,000	486,000	486,000	486,000	486,000	486,000	486,000	486,000	486,000	486,000	486,000	486,000	486,000	486,000	486,000	486,000	486,000	486,000	486,000	486,000	486,000	486,000	486,000
2038	324,000	324,000	324,000	-	-	324,000	324,000	324,000	324,000	324,000	324,000	324,000	324,000	324,000	324,000	324,000	324,000	324,000	324,000	324,000	324,000	324,000	324,000	324,000	324,000	324,000	324,000	324,000	324,000	324,000	324,000	324,000	324,000	324,000	324,000	324,000	324,000	324,000	324,000
2039	162,000	162,000	162,000	-	-	162,000	162,000	162,000	162,000	162,000	162,000	162,000	162,000	162,000	162,000	162,000	162,000	162,000	162,000	162,000	162,000	162,000	162,000	162,000	162,000	162,000	162,000	162,000	162,000	162,000	162,000	162,000	162,000	162,000	162,000	162,000	162,000	162,000	162,000
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
sources:																																							GHG model_linear decline: retail carbon (thermal, market gas, market landfill, market waste, market wood, market acs, market unspecified)

Instructions
Provide the following information for the Preferred Portfolio under the Reference Case over the study period and for at least three historical years
- Total annual GHG emissions by fuel type
- Annual GHG emissions to serve Oregon customers by fuel type
- Total annual generation by fuel type
- Annual generation serving Oregon customers by fuel type
- Annual weighted average heat rate by fuel type (total annual fuel burn, divided by total annual generation)
UM 2225 Order Summary/Rubric references: J.4(a)-(e)

PGE note 1: Fuel type may include market purchases that are DEQ tagged to the specific fuel type.

PGE note 2: Forecasts of generation from existing thermal output are based on economic dispatch using prices forecasted in this CEP/IRP. Forecasts of unspecified and other emitting market purchases are a function of historical purchases and a linear decline emission reduction glidepath. Neither reflect operational

Portfolio40 (preferred portfolio)

Fuel	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Coal	Coal	Coal	Coal	Coal	Coal	ACS	ACS	ACS	ACS	ACS	Market waste & oil	Market waste & oil	Market waste & oil	Market waste & oil	Market waste & oil	Market unspec.	Market unspec.	Market unspec.	Market unspec.	Market unspec.	Market unspec.
	Total GHG emissions	GHG emissions to serve Oregon c	Total generation	Generation serving Oregon customers	Weighted average heat rate	Total GHG emissions	GHG emissions to serve Oregon customers	Total generation	Generation serving Oregon customers	Weighted average heat rate	Total GHG emissions	GHG emissions to serve Oregon customers	Total generation	Generation serving Oregon customers	Weighted average heat rate	Total GHG emissions	GHG emissions to serve Oregon customers	Total generation	Generation serving Oregon customers	Weighted average heat rate	Total GHG emissions	GHG emissions to serve Oregon custo	Total generation	Generation serving Oregon customer	Weighted average heat rate		
Year	(metric tons)	(metric tons)	(GWh)	(GWh)	(MMBTu/MWh)	(metric tons)	(metric tons)	(GWh)	(GWh)	(MMBTu/MWh)	(metric tons)	(metric tons)	(GWh)	(GWh)	(MMBTu/MWh)	(metric tons)	(metric tons)	(GWh)	(GWh)	(MMBTu/MWh)	(metric tons)	(metric tons)	(GWh)	(GWh)	(MMBTu/MWh)		
2020	**3,164,708**	**2,615,241**	**8,062**	**6,662**	**7,419**	**3,329,087**	**2,218,519**	**3,232**	**2,172**	10,718	16,404	11,801	1402	1009	NA	111,148	93,185	91	76	NA	2,276,401	1,692,857	5319	3955	NA		
2021	3,811,894	3,150,850	9,368	7,740	7,690	2,173,398	1,450,930	2,068	1,381	10,936	22,602	16,905	1130	845	NA	68,384	58,442	69	59	NA	1,860,335	1,438,859	4347	3362	NA		
2022 (initia	3,391,937	2,850,293	8,276	6,953	7,746	2,301,034	1,300,967	2,189	1,238	10,937	43,697	34,365	2185	1718	NA	71,221	61,362	70	60	NA	2,366,604	1,814,294	5529	4239	NA		
2023	2,722,915	2,260,226	6,974	5,789	7,378	2,154,050	1,292,430	2,149	1,289	10,431	16,824	12,281	1269	926	NA	48,840	41,026	36	31	NA	3,041,538	2,281,154	6967	5225	NA		
2024	2,813,061	2,335,048	7,089	5,885	7,498	1,979,582	1,187,749	1,975	1,185	10,431	16,824	12,281	1269	926	NA		0	0	0	NA	2,364,317	1,773,238	5416	4062	NA		
2025	2,630,552	2,183,358	6,608	5,485	7,523	1,935,090	1,161,054	1,930	1,158	10,431	16,824	12,281	1269	926	NA		0	0	0	NA	2,257,218	1,692,914	5170	3878	NA		
2026	2,772,322	1,958,668	6,925	4,893	7,566	2,032,783	1,038,201	2,028	1,036	10,431	11,218	6,971	846	526	NA		0	0	0	NA	1,813,127	1,359,845	4153	3115	NA		
2027	3,131,168	1,766,970	7,701	4,346	7,684	2,007,806	819,064	2,003	817	10,431	11,218	5,568	846	420	NA		0	0	0	NA	1,448,217	1,086,163	3317	2488	NA		
2028	3,837,128	1,609,125	9,101	3,817	7,968	1,884,972	571,428	1,880	570	10,431	11,218	4,138	846	312	NA		0	0	0	NA	1,076,203	807,153	2465	1849	NA		
2029	3,818,234	1,243,091	9,060	2,950	7,965	1,839,753	432,985	1,835	432	10,431	11,218	3,212	846	242	NA		0	0	0	NA	835,510	626,632	1914	1435	NA		
2030	3,761,685	1,069,806	8,948	2,545	7,945	-	-	-	-	-	11,218	2,806	846	212	NA		0	0	0	NA	729,850	547,388	1672	1254	NA		
2031	3,745,028	961,374	8,895	2,283	7,957	-	-	-	-	-	11,218	2,533	846	191	NA		0	0	0	NA	658,792	494,094	1509	1132	NA		
2032	3,495,410	834,261	8,296	1,980	7,963	-	-	-	-	-	11,218	2,355	846	178	NA		0	0	0	NA	612,512	459,384	1403	1052	NA		
2033	3,406,727	723,270	8,093	1,718	7,955	-	-	-	-	-	11,218	2,095	846	158	NA		0	0	0	NA	544,847	408,635	1248	936	NA		
2034	3,261,723	610,122	7,738	1,448	7,966	-	-	-	-	-	11,218	1,846	846	139	NA		0	0	0	NA	480,043	360,033	1100	825	NA		
2035	3,221,129	506,061	7,660	1,203	7,948	-	-	-	-	-	11,218	1,550	846	117	NA		0	0	0	NA	403,186	302,389	924	693	NA		
2036	2,994,410	393,664	7,167	942	7,897	-	-	-	-	-	11,218	1,297	846	98	NA		0	0	0	NA	337,385	253,039	773	580	NA		
2037	2,951,594	293,577	6,997	696	7,973	-	-	-	-	-	11,218	981	846	74	NA		0	0	0	NA	255,256	191,442	585	439	NA		
2038	2,752,941	190,281	6,562	454	7,929	-	-	-	-	-	11,218	682	846	51	NA		0	0	0	NA	177,382	133,037	406	305	NA		
2039	2,654,609	93,708	6,359	224	7,890	-	-	-	-	-	11,218	348	846	26	NA		0	0	0	NA	90,592	67,944	208	156	NA		
2040	2,475,750	-	5,911	-	7,916	-	-	-	-	-	-	-	0	0	NA		0	0	0	NA	-	-	0	0	NA		
2041	2,459,879	-	5,833	-	7,970	-	-	-	-	-	-	-	0	0	NA		0	0	0	NA	-	-	0	0	NA		
2042	2,209,453	-	5,280	-	7,908	-	-	-	-	-	-	-	0	0	NA		0	0	0	NA	-	-	0	0	NA		
2043	2,300,472	-	5,490	-	7,919	-	-	-	-	-	-	-	0	0	NA		0	0	0	NA	-	-	0	0	NA		
sources	GHG model_linear decline	GHG model_linear decline	GHG model_linear decline	GHG model_linear decline	GHG model_linear decline	GHG model_linear decline	GHG model_linear decline	GHG model_linear decline	GHG model_linear decline	GHG model_linear decline	GHG model_linear decline	GHG model_linear decline	GHG model_linear decline	GHG model_linear decline	NA	GHG model_linear decline	GHG model_linear decline	GHG model_linear decline	GHG model_linear decline	NA	GHG model_linear decline	GHG model_linear decline	GHG model_linear decline	GHG model_linear decline	NA		

Instructions
For each of the portfolios listed in the "Portfolios" tab, provide the following information under the Reference Case over the study period and for at least three historical years
- Total forecasted annual revenue requirement to serve Oregon customers
- Total forecasted annual revenue requirement to serve Oregon customers, divided by the total forecasted retail sales in Oregon
UM 2225 Order Summary/Rubric references: J.5(a)-(b)

40 Portfolio40

Year	Total revenue requirement to serve Oregon customers **(energy supply costs only)** (million nominal $)	Total Oregon retail sales (MWh)	Total revenue requirement to serve Oregon customers, divided by the total retail sales in Oregon **(not projections of actual prices or rates)** (nominal $/MWh)
2019			
2020			
2021			
2022			
2023			
2024	1,658	19,683,694	$ 84
2025	1,829	20,345,758	$ 90
2026	1,772	21,049,381	$ 84
2027	1,864	21,729,469	$ 86
2028	1,853	22,549,039	$ 82
2029	2,273	22,929,458	$ 99
2030	2,585	23,384,384	$ 111
2031	3,084	23,882,221	$ 129
2032	3,656	24,479,610	$ 149
2033	4,078	25,008,275	$ 163
2034	4,532	25,688,499	$ 176
2035	5,219	26,420,813	$ 198
2036	6,040	27,260,994	$ 222
2037	7,022	27,944,115	$ 251
2038	8,351	28,693,478	$ 291
2039	9,958	29,506,392	$ 337
2040	10,807	30,422,407	$ 355
2041	13,788	31,097,455	$ 443
2042	14,344	31,814,924	$ 451
2043	14,667	32,532,336	$ 451
sources:	ART results - 100% tax incentive, 50% ownership.xlsx: Total Cost $k/1000	ART results - 100% tax incentive, 50% ownership.xlsx : Total Load MWh	ART results - 100% tax incentive, 50% ownership.xlsx : Total Cost/MWh

PGE note:

All cost figures do not include costs from the rest of the company such as grid modernization, A&G, wildfire mitigation, or T&D costs. Yearly cost impacts do not reflect actual customer prices because they do include proxy resource generation costs and do not incorporate cost changes across PGE.

Yearly costs are highly sensitive to assumptions of generic resources costs, especially after 2030. All 2030-2040 costs are modeling outputs only and should not be interpreted as projections of actual costs to serve customers due to uncertainty about actual technology availability and costs in that timeframe.

	1	Portfolio1		
Year		Total revenue requirement to serve Oregon customers (million nominal $)	Total Oregon retail sales (MWh)	Total revenue requirement to serve Oregon customers, divided by the total retail sales in Oregon (nominal $/MWh)
2019				
2020				
2021				
2022				
2023				
2024		1,658	19,683,694	$ 84
2025		1,829	20,345,758	$ 90
2026		1,772	21,049,381	$ 84
2027		1,857	21,729,469	$ 85
2028		1,848	22,549,039	$ 82
2029		2,236	22,929,458	$ 98
2030		2,874	23,384,384	$ 123
2031		3,756	23,882,221	$ 157
2032		4,614	24,479,610	$ 188
2033		5,186	25,008,275	$ 207
2034		5,785	25,688,499	$ 225
2035		6,574	26,420,813	$ 249
2036		7,655	27,260,994	$ 281
2037		9,056	27,944,115	$ 324
2038		10,562	28,693,478	$ 368
2039		12,087	29,506,392	$ 410
2040		13,595	30,422,407	$ 447
2041		14,736	31,097,455	$ 474
2042		15,290	31,814,924	$ 481
2043		15,608	32,532,336	$ 480

PGE note:

All cost figures do not include costs from the rest of the company such as grid modernization, A&G, wildfire mitigation, or T&D costs. Yearly cost impacts do not reflect actual customer prices because they do include proxy resource generation costs and do not incorporate cost changes across PGE.

Yearly costs are highly sensitive to assumptions of generic resources costs, especially after 2030. All 2030-2040 costs are modeling outputs only and should not be interpreted as projections of actual costs to serve customers due to uncertainty about actual technology availability and costs in that timeframe.

2 Portfolio2

Year	Total revenue requirement to serve Oregon customers (million nominal $)	Total Oregon retail sales (MWh)	Total revenue requirement to serve Oregon customers, divided by the total retail sales in Oregon (nominal $/MWh)
2019			
2020			
2021			
2022			
2023			
2024	1,658	19,683,694	$ 84
2025	1,829	20,345,758	$ 90
2026	1,784	21,049,381	$ 85
2027	1,883	21,729,469	$ 87
2028	2,198	22,549,039	$ 97
2029	2,810	22,929,458	$ 123
2030	3,089	23,384,384	$ 132
2031	3,723	23,882,221	$ 156
2032	4,586	24,479,610	$ 187
2033	5,155	25,008,275	$ 206
2034	5,754	25,688,499	$ 224
2035	6,549	26,420,813	$ 248
2036	7,653	27,260,994	$ 281
2037	9,108	27,944,115	$ 326
2038	10,590	28,693,478	$ 369
2039	12,092	29,506,392	$ 410
2040	13,571	30,422,407	$ 446
2041	14,713	31,097,455	$ 473
2042	15,266	31,814,924	$ 480
2043	15,584	32,532,336	$ 479

PGE note:

All cost figures do not include costs from the rest of the company such as grid modernization, A&G, wildfire mitigation, or T&D costs. Yearly cost impacts do not reflect actual customer prices because they do include proxy resource generation costs and do not incorporate cost changes across PGE.

Yearly costs are highly sensitive to assumptions of generic resources costs, especially after 2030. All 2030-2040 costs are modeling outputs only and should not be interpreted as projections of actual costs to serve customers due to uncertainty about actual technology availability and costs in that timeframe.

3 Portfolio3

Year	Total revenue requirement to serve Oregon customers (million nominal $)	Total Oregon retail sales (MWh)	Total revenue requirement to serve Oregon customers, divided by the total retail sales in Oregon (nominal $/MWh)
2019			
2020			
2021			
2022			
2023			
2024	1,658	19,683,694	$ 84
2025	1,829	20,345,758	$ 90
2026	1,748	21,049,381	$ 83
2027	1,863	21,729,469	$ 86
2028	1,846	22,549,039	$ 82
2029	1,910	22,929,458	$ 83
2030	2,501	23,384,384	$ 107
2031	3,784	23,882,221	$ 158
2032	4,637	24,479,610	$ 189
2033	5,206	25,008,275	$ 208
2034	5,808	25,688,499	$ 226
2035	6,594	26,420,813	$ 250
2036	7,664	27,260,994	$ 281
2037	9,062	27,944,115	$ 324
2038	10,538	28,693,478	$ 367
2039	12,049	29,506,392	$ 408
2040	13,612	30,422,407	$ 447
2041	14,754	31,097,455	$ 474
2042	15,308	31,814,924	$ 481
2043	15,626	32,532,336	$ 480

PGE note:

All cost figures do not include costs from the rest of the company such as grid modernization, A&G, wildfire mitigation, or T&D costs. Yearly cost impacts do not reflect actual customer prices because they do include proxy resource generation costs and do not incorporate cost changes across PGE.

Yearly costs are highly sensitive to assumptions of generic resources costs, especially after 2030. All 2030-2040 costs are modeling outputs only and should not be interpreted as projections of actual costs to serve customers due to uncertainty about actual technology availability and costs in that timeframe.

4 Portfolio4

Year	Total revenue requirement to serve Oregon customers (million nominal $)	Total Oregon retail sales (MWh)	Total revenue requirement to serve Oregon customers, divided by the total retail sales in Oregon (nominal $/MWh)
2019			
2020			
2021			
2022			
2023			
2024	1,658	19,683,694	$ 84
2025	1,829	20,345,758	$ 90
2026	1,772	21,049,381	$ 84
2027	1,857	21,729,469	$ 85
2028	1,848	22,549,039	$ 82
2029	2,236	22,929,458	$ 98
2030	2,874	23,384,384	$ 123
2031	3,822	23,882,221	$ 160
2032	4,818	24,479,610	$ 197
2033	5,537	25,008,275	$ 221
2034	6,290	25,688,499	$ 245
2035	7,219	26,420,813	$ 273
2036	8,288	27,260,994	$ 304
2037	9,511	27,944,115	$ 340
2038	10,893	28,693,478	$ 380
2039	12,230	29,506,392	$ 414
2040	13,543	30,422,407	$ 445
2041	14,578	31,097,455	$ 469
2042	15,145	31,814,924	$ 476
2043	15,475	32,532,336	$ 476

PGE note:

All cost figures do not include costs from the rest of the company such as grid modernization, A&G, wildfire mitigation, or T&D costs. Yearly cost impacts do not reflect actual customer prices because they do include proxy resource generation costs and do not incorporate cost changes across PGE.

Yearly costs are highly sensitive to assumptions of generic resources costs, especially after 2030. All 2030-2040 costs are modeling outputs only and should not be interpreted as projections of actual costs to serve customers due to uncertainty about actual technology availability and costs in that timeframe.

5 Portfolio5

Year	Total revenue requirement to serve Oregon customers (million nominal $)	Total Oregon retail sales (MWh)	Total revenue requirement to serve Oregon customers, divided by the total retail sales in Oregon (nominal $/MWh)
2019			
2020			
2021			
2022			
2023			
2024	1,658	19,683,694	$ 84
2025	1,829	20,345,758	$ 90
2026	1,772	21,049,381	$ 84
2027	1,874	21,729,469	$ 86
2028	2,243	22,549,039	$ 99
2029	3,044	22,929,458	$ 133
2030	3,329	23,384,384	$ 142
2031	3,972	23,882,221	$ 166
2032	4,838	24,479,610	$ 198
2033	5,406	25,008,275	$ 216
2034	6,001	25,688,499	$ 234
2035	6,784	26,420,813	$ 257
2036	7,865	27,260,994	$ 288
2037	9,303	27,944,115	$ 333
2038	10,846	28,693,478	$ 378
2039	12,268	29,506,392	$ 416
2040	13,556	30,422,407	$ 446
2041	14,582	31,097,455	$ 469
2042	15,140	31,814,924	$ 476
2043	15,459	32,532,336	$ 475

PGE note:

All cost figures do not include costs from the rest of the company such as grid modernization, A&G, wildfire mitigation, or T&D costs. Yearly cost impacts do not reflect actual customer prices because they do include proxy resource generation costs and do not incorporate cost changes across PGE.

Yearly costs are highly sensitive to assumptions of generic resources costs, especially after 2030. All 2030-2040 costs are modeling outputs only and should not be interpreted as projections of actual costs to serve customers due to uncertainty about actual technology availability and costs in that timeframe.

6 Portfolio6

Year	Total revenue requirement to serve Oregon customers (million nominal $)	Total Oregon retail sales (MWh)	Total revenue requirement to serve Oregon customers, divided by the total retail sales in Oregon (nominal $/MWh)
2019			
2020			
2021			
2022			
2023			
2024	1,658	19,683,694	$ 84
2025	1,829	20,345,758	$ 90
2026	1,897	21,049,381	$ 90
2027	1,962	21,729,469	$ 90
2028	1,953	22,549,039	$ 87
2029	2,291	22,929,458	$ 100
2030	2,858	23,384,384	$ 122
2031	3,534	23,882,221	$ 148
2032	4,357	24,479,610	$ 178
2033	4,934	25,008,275	$ 197
2034	5,540	25,688,499	$ 216
2035	6,325	26,420,813	$ 239
2036	7,404	27,260,994	$ 272
2037	8,801	27,944,115	$ 315
2038	10,318	28,693,478	$ 360
2039	11,844	29,506,392	$ 401
2040	13,351	30,422,407	$ 439
2041	14,494	31,097,455	$ 466
2042	15,048	31,814,924	$ 473
2043	15,367	32,532,336	$ 472

PGE note:

All cost figures do not include costs from the rest of the company such as grid modernization, A&G, wildfire mitigation, or T&D costs. Yearly cost impacts do not reflect actual customer prices because they do include proxy resource generation costs and do not incorporate cost changes across PGE.

Yearly costs are highly sensitive to assumptions of generic resources costs, especially after 2030. All 2030-2040 costs are modeling outputs only and should not be interpreted as projections of actual costs to serve customers due to uncertainty about actual technology availability and costs in that timeframe.

7 Portfolio7

Year	Total revenue requirement to serve Oregon customers (million nominal $)	Total Oregon retail sales (MWh)	Total revenue requirement to serve Oregon customers, divided by the total retail sales in Oregon (nominal $/MWh)
2019			
2020			
2021			
2022			
2023			
2024	1,658	19,683,694	$ 84
2025	1,829	20,345,758	$ 90
2026	1,772	21,049,381	$ 84
2027	1,857	21,729,469	$ 85
2028	1,848	22,549,039	$ 82
2029	2,236	22,929,458	$ 98
2030	2,874	23,384,384	$ 123
2031	3,756	23,882,221	$ 157
2032	4,614	24,479,610	$ 188
2033	5,186	25,008,275	$ 207
2034	5,785	25,688,499	$ 225
2035	6,574	26,420,813	$ 249
2036	7,655	27,260,994	$ 281
2037	9,056	27,944,115	$ 324
2038	10,562	28,693,478	$ 368
2039	12,087	29,506,392	$ 410
2040	13,595	30,422,407	$ 447
2041	14,736	31,097,455	$ 474
2042	15,290	31,814,924	$ 481
2043	15,608	32,532,336	$ 480

PGE note:

All cost figures do not include costs from the rest of the company such as grid modernization, A&G, wildfire mitigation, or T&D costs. Yearly cost impacts do not reflect actual customer prices because they do include proxy resource generation costs and do not incorporate cost changes across PGE.

Yearly costs are highly sensitive to assumptions of generic resources costs, especially after 2030. All 2030-2040 costs are modeling outputs only and should not be interpreted as projections of actual costs to serve customers due to uncertainty about actual technology availability and costs in that timeframe.

8 Portfolio8

Year	Total revenue requirement to serve Oregon customers (million nominal $)	Total Oregon retail sales (MWh)	Total revenue requirement to serve Oregon customers, divided by the total retail sales in Oregon (nominal $/MWh)
2019			
2020			
2021			
2022			
2023			
2024	1,658	19,683,694	$ 84
2025	1,829	20,345,758	$ 90
2026	1,840	21,049,381	$ 87
2027	1,966	21,729,469	$ 90
2028	1,984	22,549,039	$ 88
2029	2,413	22,929,458	$ 105
2030	3,252	23,384,384	$ 139
2031	3,505	23,882,221	$ 147
2032	4,326	24,479,610	$ 177
2033	4,899	25,008,275	$ 196
2034	5,507	25,688,499	$ 214
2035	6,294	26,420,813	$ 238
2036	7,373	27,260,994	$ 270
2037	8,770	27,944,115	$ 314
2038	10,287	28,693,478	$ 358
2039	11,813	29,506,392	$ 400
2040	13,319	30,422,407	$ 438
2041	14,461	31,097,455	$ 465
2042	15,015	31,814,924	$ 472
2043	15,335	32,532,336	$ 471

PGE note:

All cost figures do not include costs from the rest of the company such as grid modernization, A&G, wildfire mitigation, or T&D costs. Yearly cost impacts do not reflect actual customer prices because they do include proxy resource generation costs and do not incorporate cost changes across PGE.

Yearly costs are highly sensitive to assumptions of generic resources costs, especially after 2030. All 2030-2040 costs are modeling outputs only and should not be interpreted as projections of actual costs to serve customers due to uncertainty about actual technology availability and costs in that timeframe.

9 Portfolio9

Year	Total revenue requirement to serve Oregon customers (million nominal $)	Total Oregon retail sales (MWh)	Total revenue requirement to serve Oregon customers, divided by the total retail sales in Oregon (nominal $/MWh)
2019			
2020			
2021			
2022			
2023			
2024	1,658	19,683,694	$ 84
2025	1,829	20,345,758	$ 90
2026	1,772	21,049,381	$ 84
2027	1,857	21,729,469	$ 85
2028	1,848	22,549,039	$ 82
2029	2,236	22,929,458	$ 98
2030	2,874	23,384,384	$ 123
2031	3,756	23,882,221	$ 157
2032	4,614	24,479,610	$ 188
2033	5,186	25,008,275	$ 207
2034	5,785	25,688,499	$ 225
2035	6,574	26,420,813	$ 249
2036	7,655	27,260,994	$ 281
2037	9,056	27,944,115	$ 324
2038	10,562	28,693,478	$ 368
2039	12,087	29,506,392	$ 410
2040	13,595	30,422,407	$ 447
2041	14,736	31,097,455	$ 474
2042	15,290	31,814,924	$ 481
2043	15,608	32,532,336	$ 480

PGE note:

All cost figures do not include costs from the rest of the company such as grid modernization, A&G, wildfire mitigation, or T&D costs. Yearly cost impacts do not reflect actual customer prices because they do include proxy resource generation costs and do not incorporate cost changes across PGE.

Yearly costs are highly sensitive to assumptions of generic resources costs, especially after 2030. All 2030-2040 costs are modeling outputs only and should not be interpreted as projections of actual costs to serve customers due to uncertainty about actual technology availability and costs in that timeframe.

10 Portfolio10

Year	Total revenue requirement to serve Oregon customers (million nominal $)	Total Oregon retail sales (MWh)	Total revenue requirement to serve Oregon customers, divided by the total retail sales in Oregon (nominal $/MWh)
2019			
2020			
2021			
2022			
2023			
2024	1,658	19,683,694	$ 84
2025	1,829	20,345,758	$ 90
2026	1,769	21,049,381	$ 84
2027	1,855	21,729,469	$ 85
2028	1,844	22,549,039	$ 82
2029	2,241	22,929,458	$ 98
2030	2,884	23,384,384	$ 123
2031	3,780	23,882,221	$ 158
2032	4,638	24,479,610	$ 189
2033	5,209	25,008,275	$ 208
2034	5,809	25,688,499	$ 226
2035	6,601	26,420,813	$ 250
2036	7,687	27,260,994	$ 282
2037	9,093	27,944,115	$ 325
2038	10,587	28,693,478	$ 369
2039	12,111	29,506,392	$ 410
2040	13,619	30,422,407	$ 448
2041	14,761	31,097,455	$ 475
2042	15,314	31,814,924	$ 481
2043	15,631	32,532,336	$ 480

PGE note:

All cost figures do not include costs from the rest of the company such as grid modernization, A&G, wildfire mitigation, or T&D costs. Yearly cost impacts do not reflect actual customer prices because they do include proxy resource generation costs and do not incorporate cost changes across PGE.

Yearly costs are highly sensitive to assumptions of generic resources costs, especially after 2030. All 2030-2040 costs are modeling outputs only and should not be interpreted as projections of actual costs to serve customers due to uncertainty about actual technology availability and costs in that timeframe.

11 Portfolio11

Year	Total revenue requirement to serve Oregon customers (million nominal $)	Total Oregon retail sales (MWh)	Total revenue requirement to serve Oregon customers, divided by the total retail sales in Oregon (nominal $/MWh)
2019			
2020			
2021			
2022			
2023			
2024	1,658	19,683,694	$ 84
2025	1,829	20,345,758	$ 90
2026	1,760	21,049,381	$ 84
2027	1,847	21,729,469	$ 85
2028	1,832	22,549,039	$ 81
2029	2,255	22,929,458	$ 98
2030	2,918	23,384,384	$ 125
2031	3,871	23,882,221	$ 162
2032	4,714	24,479,610	$ 193
2033	5,285	25,008,275	$ 211
2034	5,885	25,688,499	$ 229
2035	6,676	26,420,813	$ 253
2036	7,763	27,260,994	$ 285
2037	9,169	27,944,115	$ 328
2038	10,659	28,693,478	$ 371
2039	12,183	29,506,392	$ 413
2040	13,691	30,422,407	$ 450
2041	14,832	31,097,455	$ 477
2042	15,385	31,814,924	$ 484
2043	15,701	32,532,336	$ 483

PGE note:

All cost figures do not include costs from the rest of the company such as grid modernization, A&G, wildfire mitigation, or T&D costs. Yearly cost impacts do not reflect actual customer prices because they do include proxy resource generation costs and do not incorporate cost changes across PGE.

Yearly costs are highly sensitive to assumptions of generic resources costs, especially after 2030. All 2030-2040 costs are modeling outputs only and should not be interpreted as projections of actual costs to serve customers due to uncertainty about actual technology availability and costs in that timeframe.

12 Portfolio12

Year	Total revenue requirement to serve Oregon customers (million nominal $)	Total Oregon retail sales (MWh)	Total revenue requirement to serve Oregon customers, divided by the total retail sales in Oregon (nominal $/MWh)
2019			
2020			
2021			
2022			
2023			
2024	1,658	19,683,694	$ 84
2025	1,829	20,345,758	$ 90
2026	1,768	21,049,381	$ 84
2027	1,853	21,729,469	$ 85
2028	1,841	22,549,039	$ 82
2029	2,245	22,929,458	$ 98
2030	2,896	23,384,384	$ 124
2031	3,787	23,882,221	$ 159
2032	4,645	24,479,610	$ 190
2033	5,216	25,008,275	$ 209
2034	5,815	25,688,499	$ 226
2035	6,605	26,420,813	$ 250
2036	7,688	27,260,994	$ 282
2037	9,091	27,944,115	$ 325
2038	10,591	28,693,478	$ 369
2039	12,116	29,506,392	$ 411
2040	13,624	30,422,407	$ 448
2041	14,765	31,097,455	$ 475
2042	15,318	31,814,924	$ 481
2043	15,636	32,532,336	$ 481

PGE note:

All cost figures do not include costs from the rest of the company such as grid modernization, A&G, wildfire mitigation, or T&D costs. Yearly cost impacts do not reflect actual customer prices because they do include proxy resource generation costs and do not incorporate cost changes across PGE.

Yearly costs are highly sensitive to assumptions of generic resources costs, especially after 2030. All 2030-2040 costs are modeling outputs only and should not be interpreted as projections of actual costs to serve customers due to uncertainty about actual technology availability and costs in that timeframe.

13 Portfolio13

Year	Total revenue requirement to serve Oregon customers (million nominal $)	Total Oregon retail sales (MWh)	Total revenue requirement to serve Oregon customers, divided by the total retail sales in Oregon (nominal $/MWh)
2019			
2020			
2021			
2022			
2023			
2024	1,658	19,683,694	$ 84
2025	1,829	20,345,758	$ 90
2026	1,772	21,049,381	$ 84
2027	1,857	21,729,469	$ 85
2028	1,848	22,549,039	$ 82
2029	2,236	22,929,458	$ 98
2030	2,874	23,384,384	$ 123
2031	3,756	23,882,221	$ 157
2032	4,614	24,479,610	$ 188
2033	5,186	25,008,275	$ 207
2034	5,785	25,688,499	$ 225
2035	6,574	26,420,813	$ 249
2036	7,655	27,260,994	$ 281
2037	9,056	27,944,115	$ 324
2038	10,562	28,693,478	$ 368
2039	12,087	29,506,392	$ 410
2040	13,595	30,422,407	$ 447
2041	14,736	31,097,455	$ 474
2042	15,290	31,814,924	$ 481
2043	15,608	32,532,336	$ 480

PGE note:

All cost figures do not include costs from the rest of the company such as grid modernization, A&G, wildfire mitigation, or T&D costs. Yearly cost impacts do not reflect actual customer prices because they do include proxy resource generation costs and do not incorporate cost changes across PGE.

Yearly costs are highly sensitive to assumptions of generic resources costs, especially after 2030. All 2030-2040 costs are modeling outputs only and should not be interpreted as projections of actual costs to serve customers due to uncertainty about actual technology availability and costs in that timeframe.

14 Portfolio14

Year	Total revenue requirement to serve Oregon customers (million nominal $)	Total Oregon retail sales (MWh)	Total revenue requirement to serve Oregon customers, divided by the total retail sales in Oregon (nominal $/MWh)
2019			
2020			
2021			
2022			
2023			
2024	1,658	19,683,694	$ 84
2025	1,829	20,345,758	$ 90
2026	1,737	21,049,381	$ 83
2027	1,810	21,729,469	$ 83
2028	1,836	22,549,039	$ 81
2029	1,888	22,929,458	$ 82
2030	1,933	23,384,384	$ 83
2031	2,059	23,882,221	$ 86
2032	2,174	24,479,610	$ 89
2033	2,207	25,008,275	$ 88
2034	2,243	25,688,499	$ 87
2035	2,341	26,420,813	$ 89
2036	2,425	27,260,994	$ 89
2037	2,603	27,944,115	$ 93
2038	3,274	28,693,478	$ 114
2039	4,242	29,506,392	$ 144
2040	5,226	30,422,407	$ 172
2041	5,943	31,097,455	$ 191
2042	5,933	31,814,924	$ 186
2043	5,927	32,532,336	$ 182

PGE note:

All cost figures do not include costs from the rest of the company such as grid modernization, A&G, wildfire mitigation, or T&D costs. Yearly cost impacts do not reflect actual customer prices because they do include proxy resource generation costs and do not incorporate cost changes across PGE.

Yearly costs are highly sensitive to assumptions of generic resources costs, especially after 2030. All 2030-2040 costs are modeling outputs only and should not be interpreted as projections of actual costs to serve customers due to uncertainty about actual technology availability and costs in that timeframe.

15 Portfolio15

Year	Total revenue requirement to serve Oregon customers (million nominal $)	Total Oregon retail sales (MWh)	Total revenue requirement to serve Oregon customers, divided by the total retail sales in Oregon (nominal $/MWh)
2019			
2020			
2021			
2022			
2023			
2024	1,658	19,683,694	$ 84
2025	1,829	20,345,758	$ 90
2026	1,772	21,049,381	$ 84
2027	1,856	21,729,469	$ 85
2028	2,022	22,549,039	$ 90
2029	2,693	22,929,458	$ 117
2030	3,435	23,384,384	$ 147
2031	4,471	23,882,221	$ 187
2032	5,315	24,479,610	$ 217
2033	5,884	25,008,275	$ 235
2034	6,479	25,688,499	$ 252
2035	7,264	26,420,813	$ 275
2036	8,343	27,260,994	$ 306
2037	9,736	27,944,115	$ 348
2038	11,226	28,693,478	$ 391
2039	12,745	29,506,392	$ 432
2040	14,258	30,422,407	$ 469
2041	15,395	31,097,455	$ 495
2042	15,944	31,814,924	$ 501
2043	16,258	32,532,336	$ 500

PGE note:

All cost figures do not include costs from the rest of the company such as grid modernization, A&G, wildfire mitigation, or T&D costs. Yearly cost impacts do not reflect actual customer prices because they do include proxy resource generation costs and do not incorporate cost changes across PGE.

Yearly costs are highly sensitive to assumptions of generic resources costs, especially after 2030. All 2030-2040 costs are modeling outputs only and should not be interpreted as projections of actual costs to serve customers due to uncertainty about actual technology availability and costs in that timeframe.

16 Portfolio16

Year	Total revenue requirement to serve Oregon customers (million nominal $)	Total Oregon retail sales (MWh)	Total revenue requirement to serve Oregon customers, divided by the total retail sales in Oregon (nominal $/MWh)
2019			
2020			
2021			
2022			
2023			
2024	1,658	19,683,694	$ 84
2025	1,829	20,345,758	$ 90
2026	1,748	21,049,381	$ 83
2027	1,863	21,729,469	$ 86
2028	1,859	22,549,039	$ 82
2029	1,939	22,929,458	$ 85
2030	1,962	23,384,384	$ 84
2031	2,093	23,882,221	$ 88
2032	2,229	24,479,610	$ 91
2033	2,265	25,008,275	$ 91
2034	2,320	25,688,499	$ 90
2035	2,400	26,420,813	$ 91
2036	2,452	27,260,994	$ 90
2037	2,715	27,944,115	$ 97
2038	3,432	28,693,478	$ 120
2039	4,430	29,506,392	$ 150
2040	5,427	30,422,407	$ 178
2041	6,117	31,097,455	$ 197
2042	6,102	31,814,924	$ 192
2043	6,106	32,532,336	$ 188

PGE note:

All cost figures do not include costs from the rest of the company such as grid modernization, A&G, wildfire mitigation, or T&D costs. Yearly cost impacts do not reflect actual customer prices because they do include proxy resource generation costs and do not incorporate cost changes across PGE.

Yearly costs are highly sensitive to assumptions of generic resources costs, especially after 2030. All 2030-2040 costs are modeling outputs only and should not be interpreted as projections of actual costs to serve customers due to uncertainty about actual technology availability and costs in that timeframe.

17 Portfolio17

Year	Total revenue requirement to serve Oregon customers (million nominal $)	Total Oregon retail sales (MWh)	Total revenue requirement to serve Oregon customers, divided by the total retail sales in Oregon (nominal $/MWh)
2019			
2020			
2021			
2022			
2023			
2024	1,658	19,683,694	$ 84
2025	1,829	20,345,758	$ 90
2026	1,748	21,049,381	$ 83
2027	1,863	21,729,469	$ 86
2028	1,858	22,549,039	$ 82
2029	1,939	22,929,458	$ 85
2030	1,963	23,384,384	$ 84
2031	2,094	23,882,221	$ 88
2032	2,229	24,479,610	$ 91
2033	2,273	25,008,275	$ 91
2034	2,316	25,688,499	$ 90
2035	2,403	26,420,813	$ 91
2036	2,429	27,260,994	$ 89
2037	2,508	27,944,115	$ 90
2038	2,889	28,693,478	$ 101
2039	3,726	29,506,392	$ 126
2040	5,201	30,422,407	$ 171
2041	5,713	31,097,455	$ 184
2042	5,702	31,814,924	$ 179
2043	5,720	32,532,336	$ 176

PGE note:

All cost figures do not include costs from the rest of the company such as grid modernization, A&G, wildfire mitigation, or T&D costs. Yearly cost impacts do not reflect actual customer prices because they do include proxy resource generation costs and do not incorporate cost changes across PGE.

Yearly costs are highly sensitive to assumptions of generic resources costs, especially after 2030. All 2030-2040 costs are modeling outputs only and should not be interpreted as projections of actual costs to serve customers due to uncertainty about actual technology availability and costs in that timeframe.

18 Portfolio18

Year	Total revenue requirement to serve Oregon customers (million nominal $)	Total Oregon retail sales (MWh)	Total revenue requirement to serve Oregon customers, divided by the total retail sales in Oregon (nominal $/MWh)
2019			
2020			
2021			
2022			
2023			
2024	1,658	19,683,694	$ 84
2025	1,829	20,345,758	$ 90
2026	1,772	21,049,381	$ 84
2027	1,864	21,729,469	$ 86
2028	1,848	22,549,039	$ 82
2029	2,234	22,929,458	$ 97
2030	2,873	23,384,384	$ 123
2031	3,755	23,882,221	$ 157
2032	4,613	24,479,610	$ 188
2033	5,185	25,008,275	$ 207
2034	5,785	25,688,499	$ 225
2035	6,573	26,420,813	$ 249
2036	7,654	27,260,994	$ 281
2037	9,072	27,944,115	$ 325
2038	10,561	28,693,478	$ 368
2039	12,087	29,506,392	$ 410
2040	13,594	30,422,407	$ 447
2041	14,736	31,097,455	$ 474
2042	15,289	31,814,924	$ 481
2043	15,607	32,532,336	$ 480

PGE note:

All cost figures do not include costs from the rest of the company such as grid modernization, A&G, wildfire mitigation, or T&D costs. Yearly cost impacts do not reflect actual customer prices because they do include proxy resource generation costs and do not incorporate cost changes across PGE.

Yearly costs are highly sensitive to assumptions of generic resources costs, especially after 2030. All 2030-2040 costs are modeling outputs only and should not be interpreted as projections of actual costs to serve customers due to uncertainty about actual technology availability and costs in that timeframe.

19 Portfolio19

Year	Total revenue requirement to serve Oregon customers (million nominal $)	Total Oregon retail sales (MWh)	Total revenue requirement to serve Oregon customers, divided by the total retail sales in Oregon (nominal $/MWh)
2019			
2020			
2021			
2022			
2023			
2024	1,658	19,683,694	$ 84
2025	1,829	20,345,758	$ 90
2026	1,772	21,049,381	$ 84
2027	1,856	21,729,469	$ 85
2028	2,022	22,549,039	$ 90
2029	2,499	22,929,458	$ 109
2030	2,864	23,384,384	$ 122
2031	3,750	23,882,221	$ 157
2032	4,608	24,479,610	$ 188
2033	5,176	25,008,275	$ 207
2034	5,775	25,688,499	$ 225
2035	6,564	26,420,813	$ 248
2036	7,646	27,260,994	$ 280
2037	9,039	27,944,115	$ 323
2038	10,550	28,693,478	$ 368
2039	12,079	29,506,392	$ 409
2040	13,587	30,422,407	$ 447
2041	14,728	31,097,455	$ 474
2042	15,282	31,814,924	$ 480
2043	15,600	32,532,336	$ 480

PGE note:

All cost figures do not include costs from the rest of the company such as grid modernization, A&G, wildfire mitigation, or T&D costs. Yearly cost impacts do not reflect actual customer prices because they do include proxy resource generation costs and do not incorporate cost changes across PGE.

Yearly costs are highly sensitive to assumptions of generic resources costs, especially after 2030. All 2030-2040 costs are modeling outputs only and should not be interpreted as projections of actual costs to serve customers due to uncertainty about actual technology availability and costs in that timeframe.

20 Portfolio20

Year	Total revenue requirement to serve Oregon customers (million nominal $)	Total Oregon retail sales (MWh)	Total revenue requirement to serve Oregon customers, divided by the total retail sales in Oregon (nominal $/MWh)
2019			
2020			
2021			
2022			
2023			
2024	1,658	19,683,694	$ 84
2025	1,829	20,345,758	$ 90
2026	1,986	21,049,381	$ 94
2027	2,015	21,729,469	$ 93
2028	1,998	22,549,039	$ 89
2029	2,430	22,929,458	$ 106
2030	3,081	23,384,384	$ 132
2031	3,846	23,882,221	$ 161
2032	4,608	24,479,610	$ 188
2033	5,182	25,008,275	$ 207
2034	5,790	25,688,499	$ 225
2035	6,575	26,420,813	$ 249
2036	7,675	27,260,994	$ 282
2037	9,053	27,944,115	$ 324
2038	10,574	28,693,478	$ 369
2039	12,101	29,506,392	$ 410
2040	13,610	30,422,407	$ 447
2041	14,746	31,097,455	$ 474
2042	15,299	31,814,924	$ 481
2043	15,618	32,532,336	$ 480

PGE note:

All cost figures do not include costs from the rest of the company such as grid modernization, A&G, wildfire mitigation, or T&D costs. Yearly cost impacts do not reflect actual customer prices because they do include proxy resource generation costs and do not incorporate cost changes across PGE.

Yearly costs are highly sensitive to assumptions of generic resources costs, especially after 2030. All 2030-2040 costs are modeling outputs only and should not be interpreted as projections of actual costs to serve customers due to uncertainty about actual technology availability and costs in that timeframe.

21 Portfolio21

Year	Total revenue requirement to serve Oregon customers (million nominal $)	Total Oregon retail sales (MWh)	Total revenue requirement to serve Oregon customers, divided by the total retail sales in Oregon (nominal $/MWh)
2019			
2020			
2021			
2022			
2023			
2024	1,658	19,683,694	$ 84
2025	1,829	20,345,758	$ 90
2026	2,018	21,049,381	$ 96
2027	2,044	21,729,469	$ 94
2028	2,043	22,549,039	$ 91
2029	2,566	22,929,458	$ 112
2030	3,266	23,384,384	$ 140
2031	3,994	23,882,221	$ 167
2032	4,709	24,479,610	$ 192
2033	5,285	25,008,275	$ 211
2034	5,892	25,688,499	$ 229
2035	6,676	26,420,813	$ 253
2036	7,764	27,260,994	$ 285
2037	9,145	27,944,115	$ 327
2038	10,674	28,693,478	$ 372
2039	12,199	29,506,392	$ 413
2040	13,708	30,422,407	$ 451
2041	14,838	31,097,455	$ 477
2042	15,390	31,814,924	$ 484
2043	15,710	32,532,336	$ 483

PGE note:

All cost figures do not include costs from the rest of the company such as grid modernization, A&G, wildfire mitigation, or T&D costs. Yearly cost impacts do not reflect actual customer prices because they do include proxy resource generation costs and do not incorporate cost changes across PGE.

Yearly costs are highly sensitive to assumptions of generic resources costs, especially after 2030. All 2030-2040 costs are modeling outputs only and should not be interpreted as projections of actual costs to serve customers due to uncertainty about actual technology availability and costs in that timeframe.

22 Portfolio22

Year	Total revenue requirement to serve Oregon customers (million nominal $)	Total Oregon retail sales (MWh)	Total revenue requirement to serve Oregon customers, divided by the total retail sales in Oregon (nominal $/MWh)
2019			
2020			
2021			
2022			
2023			
2024	1,658	19,683,694	$ 84
2025	1,829	20,345,758	$ 90
2026	1,772	21,049,381	$ 84
2027	1,856	21,729,469	$ 85
2028	2,090	22,549,039	$ 93
2029	2,446	22,929,458	$ 107
2030	3,097	23,384,384	$ 132
2031	3,858	23,882,221	$ 162
2032	4,619	24,479,610	$ 189
2033	5,194	25,008,275	$ 208
2034	5,802	25,688,499	$ 226
2035	6,587	26,420,813	$ 249
2036	7,666	27,260,994	$ 281
2037	9,058	27,944,115	$ 324
2038	10,585	28,693,478	$ 369
2039	12,112	29,506,392	$ 410
2040	13,621	30,422,407	$ 448
2041	14,757	31,097,455	$ 475
2042	15,309	31,814,924	$ 481
2043	15,627	32,532,336	$ 480

PGE note:

All cost figures do not include costs from the rest of the company such as grid modernization, A&G, wildfire mitigation, or T&D costs. Yearly cost impacts do not reflect actual customer prices because they do include proxy resource generation costs and do not incorporate cost changes across PGE.

Yearly costs are highly sensitive to assumptions of generic resources costs, especially after 2030. All 2030-2040 costs are modeling outputs only and should not be interpreted as projections of actual costs to serve customers due to uncertainty about actual technology availability and costs in that timeframe.

23 Portfolio23

Year	Total revenue requirement to serve Oregon customers (million nominal $)	Total Oregon retail sales (MWh)	Total revenue requirement to serve Oregon customers, divided by the total retail sales in Oregon (nominal $/MWh)
2019			
2020			
2021			
2022			
2023			
2024	1,658	19,683,694	$ 84
2025	1,829	20,345,758	$ 90
2026	1,772	21,049,381	$ 84
2027	1,856	21,729,469	$ 85
2028	2,125	22,549,039	$ 94
2029	2,569	22,929,458	$ 112
2030	3,271	23,384,384	$ 140
2031	3,999	23,882,221	$ 167
2032	4,714	24,479,610	$ 193
2033	5,290	25,008,275	$ 212
2034	5,898	25,688,499	$ 230
2035	6,682	26,420,813	$ 253
2036	7,760	27,260,994	$ 285
2037	9,152	27,944,115	$ 327
2038	10,679	28,693,478	$ 372
2039	12,205	29,506,392	$ 414
2040	13,713	30,422,407	$ 451
2041	14,843	31,097,455	$ 477
2042	15,395	31,814,924	$ 484
2043	15,714	32,532,336	$ 483

PGE note:

All cost figures do not include costs from the rest of the company such as grid modernization, A&G, wildfire mitigation, or T&D costs. Yearly cost impacts do not reflect actual customer prices because they do include proxy resource generation costs and do not incorporate cost changes across PGE.

Yearly costs are highly sensitive to assumptions of generic resources costs, especially after 2030. All 2030-2040 costs are modeling outputs only and should not be interpreted as projections of actual costs to serve customers due to uncertainty about actual technology availability and costs in that timeframe.

24 Portfolio24

Year	Total revenue requirement to serve Oregon customers (million nominal $)	Total Oregon retail sales (MWh)	Total revenue requirement to serve Oregon customers, divided by the total retail sales in Oregon (nominal $/MWh)
2019			
2020			
2021			
2022			
2023			
2024	1,658	19,683,694	$ 84
2025	1,829	20,345,758	$ 90
2026	1,772	21,049,381	$ 84
2027	1,858	21,729,469	$ 85
2028	1,846	22,549,039	$ 82
2029	2,235	22,929,458	$ 97
2030	2,869	23,384,384	$ 123
2031	3,822	23,882,221	$ 160
2032	4,665	24,479,610	$ 191
2033	5,235	25,008,275	$ 209
2034	5,837	25,688,499	$ 227
2035	6,630	26,420,813	$ 251
2036	7,717	27,260,994	$ 283
2037	9,126	27,944,115	$ 327
2038	10,613	28,693,478	$ 370
2039	12,138	29,506,392	$ 411
2040	13,647	30,422,407	$ 449
2041	14,789	31,097,455	$ 476
2042	15,342	31,814,924	$ 482
2043	15,659	32,532,336	$ 481

PGE note:

All cost figures do not include costs from the rest of the company such as grid modernization, A&G, wildfire mitigation, or T&D costs. Yearly cost impacts do not reflect actual customer prices because they do include proxy resource generation costs and do not incorporate cost changes across PGE.

Yearly costs are highly sensitive to assumptions of generic resources costs, especially after 2030. All 2030-2040 costs are modeling outputs only and should not be interpreted as projections of actual costs to serve customers due to uncertainty about actual technology availability and costs in that timeframe.

25 Portfolio25

Year	Total revenue requirement to serve Oregon customers (million nominal $)	Total Oregon retail sales (MWh)	Total revenue requirement to serve Oregon customers, divided by the total retail sales in Oregon (nominal $/MWh)
2019			
2020			
2021			
2022			
2023			
2024	1,658	19,683,694	$ 84
2025	1,829	20,345,758	$ 90
2026	1,772	21,049,381	$ 84
2027	1,857	21,729,469	$ 85
2028	1,848	22,549,039	$ 82
2029	2,236	22,929,458	$ 98
2030	2,874	23,384,384	$ 123
2031	3,756	23,882,221	$ 157
2032	4,614	24,479,610	$ 188
2033	5,186	25,008,275	$ 207
2034	5,785	25,688,499	$ 225
2035	6,574	26,420,813	$ 249
2036	7,655	27,260,994	$ 281
2037	9,056	27,944,115	$ 324
2038	10,562	28,693,478	$ 368
2039	12,087	29,506,392	$ 410
2040	13,595	30,422,407	$ 447
2041	14,736	31,097,455	$ 474
2042	15,290	31,814,924	$ 481
2043	15,608	32,532,336	$ 480

PGE note:

All cost figures do not include costs from the rest of the company such as grid modernization, A&G, wildfire mitigation, or T&D costs. Yearly cost impacts do not reflect actual customer prices because they do include proxy resource generation costs and do not incorporate cost changes across PGE.

Yearly costs are highly sensitive to assumptions of generic resources costs, especially after 2030. All 2030-2040 costs are modeling outputs only and should not be interpreted as projections of actual costs to serve customers due to uncertainty about actual technology availability and costs in that timeframe.

26 Portfolio26

Year	Total revenue requirement to serve Oregon customers (million nominal $)	Total Oregon retail sales (MWh)	Total revenue requirement to serve Oregon customers, divided by the total retail sales in Oregon (nominal $/MWh)
2019			
2020			
2021			
2022			
2023			
2024	1,658	19,683,694	$ 84
2025	1,829	20,345,758	$ 90
2026	1,772	21,049,381	$ 84
2027	1,857	21,729,469	$ 85
2028	1,848	22,549,039	$ 82
2029	2,101	22,929,458	$ 92
2030	2,528	23,384,384	$ 108
2031	3,453	23,882,221	$ 145
2032	4,311	24,479,610	$ 176
2033	4,898	25,008,275	$ 196
2034	5,512	25,688,499	$ 215
2035	6,364	26,420,813	$ 241
2036	7,522	27,260,994	$ 276
2037	8,931	27,944,115	$ 320
2038	10,441	28,693,478	$ 364
2039	11,990	29,506,392	$ 406
2040	13,595	30,422,407	$ 447
2041	14,836	31,097,455	$ 477
2042	15,388	31,814,924	$ 484
	15,705	32,532,336	$ 483

PGE note:

All cost figures do not include costs from the rest of the company such as grid modernization, A&G, wildfire mitigation, or T&D costs. Yearly cost impacts do not reflect actual customer prices because they do include proxy resource generation costs and do not incorporate cost changes across PGE.

Yearly costs are highly sensitive to assumptions of generic resources costs, especially after 2030. All 2030-2040 costs are modeling outputs only and should not be interpreted as projections of actual costs to serve customers due to uncertainty about actual technology availability and costs in that timeframe.

27 Portfolio27

Year	Total revenue requirement to serve Oregon customers (million nominal $)	Total Oregon retail sales (MWh)	Total revenue requirement to serve Oregon customers, divided by the total retail sales in Oregon (nominal $/MWh)
2019			
2020			
2021			
2022			
2023			
2024	1,658	19,683,694	$ 84
2025	1,829	20,345,758	$ 90
2026	1,772	21,049,381	$ 84
2027	1,857	21,729,469	$ 85
2028	1,848	22,549,039	$ 82
2029	2,218	22,929,458	$ 97
2030	2,905	23,384,384	$ 124
2031	3,700	23,882,221	$ 155
2032	4,504	24,479,610	$ 184
2033	5,081	25,008,275	$ 203
2034	5,685	25,688,499	$ 221
2035	6,463	26,420,813	$ 245
2036	7,539	27,260,994	$ 277
2037	8,938	27,944,115	$ 320
2038	10,457	28,693,478	$ 364
2039	12,018	29,506,392	$ 407
2040	13,525	30,422,407	$ 445
2041	14,664	31,097,455	$ 472
2042	15,220	31,814,924	$ 478
	15,541	32,532,336	$ 478

PGE note:

All cost figures do not include costs from the rest of the company such as grid modernization, A&G, wildfire mitigation, or T&D costs. Yearly cost impacts do not reflect actual customer prices because they do include proxy resource generation costs and do not incorporate cost changes across PGE.

Yearly costs are highly sensitive to assumptions of generic resources costs, especially after 2030. All 2030-2040 costs are modeling outputs only and should not be interpreted as projections of actual costs to serve customers due to uncertainty about actual technology availability and costs in that timeframe.

28 Portfolio28

Year	Total revenue requirement to serve Oregon customers (million nominal $)	Total Oregon retail sales (MWh)	Total revenue requirement to serve Oregon customers, divided by the total retail sales in Oregon (nominal $/MWh)
2019			
2020			
2021			
2022			
2023			
2024	1,658	19,683,694	$ 84
2025	1,829	20,345,758	$ 90
2026	1,772	21,049,381	$ 84
2027	1,857	21,729,469	$ 85
2028	1,848	22,549,039	$ 82
2029	2,236	22,929,458	$ 98
2030	2,874	23,384,384	$ 123
2031	3,704	23,882,221	$ 155
2032	4,361	24,479,610	$ 178
2033	4,423	25,008,275	$ 177
2034	4,753	25,688,499	$ 185
2035	5,556	26,420,813	$ 210
2036	6,652	27,260,994	$ 244
2037	8,065	27,944,115	$ 289
2038	9,568	28,693,478	$ 333
2039	11,093	29,506,392	$ 376
2040	12,611	30,422,407	$ 415
2041	13,750	31,097,455	$ 442
2042	14,341	31,814,924	$ 451
2043	14,637	32,532,336	$ 450

PGE note:

All cost figures do not include costs from the rest of the company such as grid modernization, A&G, wildfire mitigation, or T&D costs. Yearly cost impacts do not reflect actual customer prices because they do include proxy resource generation costs and do not incorporate cost changes across PGE.

Yearly costs are highly sensitive to assumptions of generic resources costs, especially after 2030. All 2030-2040 costs are modeling outputs only and should not be interpreted as projections of actual costs to serve customers due to uncertainty about actual technology availability and costs in that timeframe.

29 Portfolio29

Year	Total revenue requirement to serve Oregon customers (million nominal $)	Total Oregon retail sales (MWh)	Total revenue requirement to serve Oregon customers, divided by the total retail sales in Oregon (nominal $/MWh)
2019			
2020			
2021			
2022			
2023			
2024	1,658	19,683,694	$ 84
2025	1,829	20,345,758	$ 90
2026	1,772	21,049,381	$ 84
2027	1,857	21,729,469	$ 85
2028	1,798	22,549,039	$ 80
2029	2,350	22,929,458	$ 102
2030	3,009	23,384,384	$ 129
2031	3,779	23,882,221	$ 158
2032	4,552	24,479,610	$ 186
2033	5,126	25,008,275	$ 205
2034	5,732	25,688,499	$ 223
2035	6,514	26,420,813	$ 247
2036	7,589	27,260,994	$ 278
2037	8,988	27,944,115	$ 322
2038	10,506	28,693,478	$ 366
2039	12,031	29,506,392	$ 408
2040	13,540	30,422,407	$ 445
2041	14,675	31,097,455	$ 472
2042	15,228	31,814,924	$ 479
2043	15,546	32,532,336	$ 478

PGE note:

All cost figures do not include costs from the rest of the company such as grid modernization, A&G, wildfire mitigation, or T&D costs. Yearly cost impacts do not reflect actual customer prices because they do include proxy resource generation costs and do not incorporate cost changes across PGE.

Yearly costs are highly sensitive to assumptions of generic resources costs, especially after 2030. All 2030-2040 costs are modeling outputs only and should not be interpreted as projections of actual costs to serve customers due to uncertainty about actual technology availability and costs in that timeframe.

30 Portfolio30

Year	Total revenue requirement to serve Oregon customers (million nominal $)	Total Oregon retail sales (MWh)	Total revenue requirement to serve Oregon customers, divided by the total retail sales in Oregon (nominal $/MWh)
2019			
2020			
2021			
2022			
2023			
2024	1,658	19,683,694	$ 84
2025	1,829	20,345,758	$ 90
2026	1,772	21,049,381	$ 84
2027	1,857	21,729,469	$ 85
2028	1,729	22,549,039	$ 77
2029	2,401	22,929,458	$ 105
2030	3,067	23,384,384	$ 131
2031	3,783	23,882,221	$ 158
2032	4,485	24,479,610	$ 183
2033	5,063	25,008,275	$ 202
2034	5,672	25,688,499	$ 221
2035	6,452	26,420,813	$ 244
2036	7,525	27,260,994	$ 276
2037	8,925	27,944,115	$ 319
2038	10,446	28,693,478	$ 364
2039	11,973	29,506,392	$ 406
2040	13,484	30,422,407	$ 443
2041	14,615	31,097,455	$ 470
2042	15,171	31,814,924	$ 477
2043	15,492	32,532,336	$ 476

PGE note:

All cost figures do not include costs from the rest of the company such as grid modernization, A&G, wildfire mitigation, or T&D costs. Yearly cost impacts do not reflect actual customer prices because they do include proxy resource generation costs and do not incorporate cost changes across PGE.

Yearly costs are highly sensitive to assumptions of generic resources costs, especially after 2030. All 2030-2040 costs are modeling outputs only and should not be interpreted as projections of actual costs to serve customers due to uncertainty about actual technology availability and costs in that timeframe.

31 Portfolio31

Year	Total revenue requirement to serve Oregon customers (million nominal $)	Total Oregon retail sales (MWh)	Total revenue requirement to serve Oregon customers, divided by the total retail sales in Oregon (nominal $/MWh)
2019			
2020			
2021			
2022			
2023			
2024	1,658	19,683,694	$ 84
2025	1,829	20,345,758	$ 90
2026	1,772	21,049,381	$ 84
2027	1,857	21,729,469	$ 85
2028	1,848	22,549,039	$ 82
2029	2,236	22,929,458	$ 98
2030	2,874	23,384,384	$ 123
2031	3,640	23,882,221	$ 152
2032	4,351	24,479,610	$ 178
2033	4,928	25,008,275	$ 197
2034	5,530	25,688,499	$ 215
2035	6,320	26,420,813	$ 239
2036	7,404	27,260,994	$ 272
2037	8,809	27,944,115	$ 315
2038	10,318	28,693,478	$ 360
2039	11,846	29,506,392	$ 401
2040	13,355	30,422,407	$ 439
2041	14,483	31,097,455	$ 466
2042	15,038	31,814,924	$ 473
2043	15,358	32,532,336	$ 472

PGE note:

All cost figures do not include costs from the rest of the company such as grid modernization, A&G, wildfire mitigation, or T&D costs. Yearly cost impacts do not reflect actual customer prices because they do include proxy resource generation costs and do not incorporate cost changes across PGE.

Yearly costs are highly sensitive to assumptions of generic resources costs, especially after 2030. All 2030-2040 costs are modeling outputs only and should not be interpreted as projections of actual costs to serve customers due to uncertainty about actual technology availability and costs in that timeframe.

32 Portfolio32

Year	Total revenue requirement to serve Oregon customers (million nominal $)	Total Oregon retail sales (MWh)	Total revenue requirement to serve Oregon customers, divided by the total retail sales in Oregon (nominal $/MWh)
2019			
2020			
2021			
2022			
2023			
2024	1,658	19,683,694	$ 84
2025	1,829	20,345,758	$ 90
2026	1,772	21,049,381	$ 84
2027	1,857	21,729,469	$ 85
2028	1,848	22,549,039	$ 82
2029	2,236	22,929,458	$ 98
2030	2,874	23,384,384	$ 123
2031	3,756	23,882,221	$ 157
2032	4,614	24,479,610	$ 188
2033	5,186	25,008,275	$ 207
2034	5,785	25,688,499	$ 225
2035	6,574	26,420,813	$ 249
2036	7,655	27,260,994	$ 281
2037	9,056	27,944,115	$ 324
2038	10,562	28,693,478	$ 368
2039	12,087	29,506,392	$ 410
2040	13,595	30,422,407	$ 447
2041	14,736	31,097,455	$ 474
2042	15,290	31,814,924	$ 481
2043	15,608	32,532,336	$ 480

PGE note:

All cost figures do not include costs from the rest of the company such as grid modernization, A&G, wildfire mitigation, or T&D costs. Yearly cost impacts do not reflect actual customer prices because they do include proxy resource generation costs and do not incorporate cost changes across PGE.

Yearly costs are highly sensitive to assumptions of generic resources costs, especially after 2030. All 2030-2040 costs are modeling outputs only and should not be interpreted as projections of actual costs to serve customers due to uncertainty about actual technology availability and costs in that timeframe.

33 Portfolio33

Year	Total revenue requirement to serve Oregon customers (million nominal $)	Total Oregon retail sales (MWh)	Total revenue requirement to serve Oregon customers, divided by the total retail sales in Oregon (nominal $/MWh)
2019			
2020			
2021			
2022			
2023			
2024	1,639	19,683,694	$ 83
2025	1,794	20,345,758	$ 88
2026	1,752	21,049,381	$ 83
2027	1,823	21,729,469	$ 84
2028	1,808	22,549,039	$ 80
2029	1,868	22,929,458	$ 81
2030	1,938	23,384,384	$ 83
2031	2,493	23,882,221	$ 104
2032	3,589	24,479,610	$ 147
2033	4,332	25,008,275	$ 173
2034	4,859	25,688,499	$ 189
2035	5,584	26,420,813	$ 211
2036	6,159	27,260,994	$ 226
2037	6,950	27,944,115	$ 249
2038	7,941	28,693,478	$ 277
2039	9,297	29,506,392	$ 315
2040	10,805	30,422,407	$ 355
2041	12,278	31,097,455	$ 395
2042	13,464	31,814,924	$ 423
2043	14,050	32,532,336	$ 432

PGE note:

All cost figures do not include costs from the rest of the company such as grid modernization, A&G, wildfire mitigation, or T&D costs. Yearly cost impacts do not reflect actual customer prices because they do include proxy resource generation costs and do not incorporate cost changes across PGE.

Yearly costs are highly sensitive to assumptions of generic resources costs, especially after 2030. All 2030-2040 costs are modeling outputs only and should not be interpreted as projections of actual costs to serve customers due to uncertainty about actual technology availability and costs in that timeframe.

34 Portfolio34

Year	Total revenue requirement to serve Oregon customers (million nominal $)	Total Oregon retail sales (MWh)	Total revenue requirement to serve Oregon customers, divided by the total retail sales in Oregon (nominal $/MWh)
2019			
2020			
2021			
2022			
2023			
2024	1,658	19,683,694	$ 84
2025	1,829	20,345,758	$ 90
2026	1,781	21,049,381	$ 85
2027	1,857	21,729,469	$ 85
2028	1,850	22,549,039	$ 82
2029	2,198	22,929,458	$ 96
2030	2,800	23,384,384	$ 120
2031	4,460	23,882,221	$ 187
2032	6,060	24,479,610	$ 248
2033	6,364	25,008,275	$ 254
2034	7,168	25,688,499	$ 279
2035	8,225	26,420,813	$ 311
2036	8,792	27,260,994	$ 323
2037	9,761	27,944,115	$ 349
2038	11,273	28,693,478	$ 393
2039	12,637	29,506,392	$ 428
2040	13,889	30,422,407	$ 457
2041	15,493	31,097,455	$ 498
2042	16,518	31,814,924	$ 519
2043	16,806	32,532,336	$ 517

PGE note:

All cost figures do not include costs from the rest of the company such as grid modernization, A&G, wildfire mitigation, or T&D costs. Yearly cost impacts do not reflect actual customer prices because they do include proxy resource generation costs and do not incorporate cost changes across PGE.

Yearly costs are highly sensitive to assumptions of generic resources costs, especially after 2030. All 2030-2040 costs are modeling outputs only and should not be interpreted as projections of actual costs to serve customers due to uncertainty about actual technology availability and costs in that timeframe.

35 Portfolio35

Year	Total revenue requirement to serve Oregon customers (million nominal $)	Total Oregon retail sales (MWh)	Total revenue requirement to serve Oregon customers, divided by the total retail sales in Oregon (nominal $/MWh)
2019			
2020			
2021			
2022			
2023			
2024	1,658	19,683,694	$ 84
2025	1,829	20,345,758	$ 90
2026	1,772	21,049,381	$ 84
2027	1,864	21,729,469	$ 86
2028	1,853	22,549,039	$ 82
2029	2,273	22,929,458	$ 99
2030	2,585	23,384,384	$ 111
2031	3,084	23,882,221	$ 129
2032	3,656	24,479,610	$ 149
2033	4,078	25,008,275	$ 163
2034	4,532	25,688,499	$ 176
2035	5,244	26,420,813	$ 198
2036	6,323	27,260,994	$ 232
2037	7,780	27,944,115	$ 278
2038	9,300	28,693,478	$ 324
2039	10,848	29,506,392	$ 368
2040	12,374	30,422,407	$ 407
2041	13,509	31,097,455	$ 434
2042	14,066	31,814,924	$ 442
2043	14,386	32,532,336	$ 442

PGE note:

All cost figures do not include costs from the rest of the company such as grid modernization, A&G, wildfire mitigation, or T&D costs. Yearly cost impacts do not reflect actual customer prices because they do include proxy resource generation costs and do not incorporate cost changes across PGE.

Yearly costs are highly sensitive to assumptions of generic resources costs, especially after 2030. All 2030-2040 costs are modeling outputs only and should not be interpreted as projections of actual costs to serve customers due to uncertainty about actual technology availability and costs in that timeframe.

36 Portfolio36

Year	Total revenue requirement to serve Oregon customers (million nominal $)	Total Oregon retail sales (MWh)	Total revenue requirement to serve Oregon customers, divided by the total retail sales in Oregon (nominal $/MWh)
2019			
2020			
2021			
2022			
2023			
2024	1,658	19,683,694	$ 84
2025	1,829	20,345,758	$ 90
2026	1,828	21,049,381	$ 87
2027	1,931	21,729,469	$ 89
2028	1,960	22,549,039	$ 87
2029	2,280	22,929,458	$ 99
2030	2,984	23,384,384	$ 128
2031	3,546	23,882,221	$ 148
2032	4,371	24,479,610	$ 179
2033	4,948	25,008,275	$ 198
2034	5,553	25,688,499	$ 216
2035	6,340	26,420,813	$ 240
2036	7,419	27,260,994	$ 272
2037	8,816	27,944,115	$ 315
2038	10,332	28,693,478	$ 360
2039	11,858	29,506,392	$ 402
2040	13,366	30,422,407	$ 439
2041	14,508	31,097,455	$ 467
2042	15,061	31,814,924	$ 473
2043	15,381	32,532,336	$ 473

PGE note:

All cost figures do not include costs from the rest of the company such as grid modernization, A&G, wildfire mitigation, or T&D costs. Yearly cost impacts do not reflect actual customer prices because they do include proxy resource generation costs and do not incorporate cost changes across PGE.

Yearly costs are highly sensitive to assumptions of generic resources costs, especially after 2030. All 2030-2040 costs are modeling outputs only and should not be interpreted as projections of actual costs to serve customers due to uncertainty about actual technology availability and costs in that timeframe.

37 Portfolio37

Year	Total revenue requirement to serve Oregon customers (million nominal $)	Total Oregon retail sales (MWh)	Total revenue requirement to serve Oregon customers, divided by the total retail sales in Oregon (nominal $/MWh)
2019			
2020			
2021			
2022			
2023			
2024	1,658	19,683,694	$ 84
2025	1,829	20,345,758	$ 90
2026	1,800	21,049,381	$ 86
2027	1,885	21,729,469	$ 87
2028	1,879	22,549,039	$ 83
2029	2,239	22,929,458	$ 98
2030	2,869	23,384,384	$ 123
2031	3,649	23,882,221	$ 153
2032	4,489	24,479,610	$ 183
2033	5,072	25,008,275	$ 203
2034	5,670	25,688,499	$ 221
2035	6,456	26,420,813	$ 244
2036	7,534	27,260,994	$ 276
2037	8,931	27,944,115	$ 320
2038	10,447	28,693,478	$ 364
2039	11,973	29,506,392	$ 406
2040	13,479	30,422,407	$ 443
2041	14,622	31,097,455	$ 470
2042	15,176	31,814,924	$ 477
2043	15,495	32,532,336	$ 476

PGE note:

All cost figures do not include costs from the rest of the company such as grid modernization, A&G, wildfire mitigation, or T&D costs. Yearly cost impacts do not reflect actual customer prices because they do include proxy resource generation costs and do not incorporate cost changes across PGE.

Yearly costs are highly sensitive to assumptions of generic resources costs, especially after 2030. All 2030-2040 costs are modeling outputs only and should not be interpreted as projections of actual costs to serve customers due to uncertainty about actual technology availability and costs in that timeframe.

38 Portfolio38

Year	Total revenue requirement to serve Oregon customers (million nominal $)	Total Oregon retail sales (MWh)	Total revenue requirement to serve Oregon customers, divided by the total retail sales in Oregon (nominal $/MWh)
2019			
2020			
2021			
2022			
2023			
2024	1,658	19,683,694	$ 84
2025	1,829	20,345,758	$ 90
2026	2,177	21,049,381	$ 103
2027	2,150	21,729,469	$ 99
2028	2,141	22,549,039	$ 95
2029	2,561	22,929,458	$ 112
2030	3,008	23,384,384	$ 129
2031	3,467	23,882,221	$ 145
2032	4,281	24,479,610	$ 175
2033	4,852	25,008,275	$ 194
2034	5,461	25,688,499	$ 213
2035	6,248	26,420,813	$ 236
2036	7,327	27,260,994	$ 269
2037	8,724	27,944,115	$ 312
2038	10,241	28,693,478	$ 357
2039	11,767	29,506,392	$ 399
2040	13,273	30,422,407	$ 436
2041	14,415	31,097,455	$ 464
2042	14,969	31,814,924	$ 471
2043	15,289	32,532,336	$ 470

PGE note:

All cost figures do not include costs from the rest of the company such as grid modernization, A&G, wildfire mitigation, or T&D costs. Yearly cost impacts do not reflect actual customer prices because they do include proxy resource generation costs and do not incorporate cost changes across PGE.

Yearly costs are highly sensitive to assumptions of generic resources costs, especially after 2030. All 2030-2040 costs are modeling outputs only and should not be interpreted as projections of actual costs to serve customers due to uncertainty about actual technology availability and costs in that timeframe.

39 Portfolio39

Year	Total revenue requirement to serve Oregon customers (million nominal $)	Total Oregon retail sales (MWh)	Total revenue requirement to serve Oregon customers, divided by the total retail sales in Oregon (nominal $/MWh)
2019			
2020			
2021			
2022			
2023			
2024	1,658	19,683,694	$ 84
2025	1,829	20,345,758	$ 90
2026	1,897	21,049,381	$ 90
2027	1,962	21,729,469	$ 90
2028	1,957	22,549,039	$ 87
2029	2,298	22,929,458	$ 100
2030	2,625	23,384,384	$ 112
2031	2,916	23,882,221	$ 122
2032	3,493	24,479,610	$ 143
2033	3,908	25,008,275	$ 156
2034	4,352	25,688,499	$ 169
2035	5,007	26,420,813	$ 190
2036	6,044	27,260,994	$ 222
2037	7,505	27,944,115	$ 269
2038	9,038	28,693,478	$ 315
2039	10,587	29,506,392	$ 359
2040	12,114	30,422,407	$ 398
2041	13,251	31,097,455	$ 426
2042	13,810	31,814,924	$ 434
2043	14,133	32,532,336	$ 434

PGE note:

All cost figures do not include costs from the rest of the company such as grid modernization, A&G, wildfire mitigation, or T&D costs. Yearly cost impacts do not reflect actual customer prices because they do include proxy resource generation costs and do not incorporate cost changes across PGE.

Yearly costs are highly sensitive to assumptions of generic resources costs, especially after 2030. All 2030-2040 costs are modeling outputs only and should not be interpreted as projections of actual costs to serve customers due to uncertainty about actual technology availability and costs in that timeframe.

Instructions

Provide, for renewable energy generated by or contracted to the utility in the Preferred Portfolio under the Reference Case over the entire analysis horizon (at least 20 years), the following information:.
- RECs that are expected to be retired on behalf of Oregon customer load for RPS compliance in Oregon
- RECs that are expected to be retired on behalf of Oregon customer load for voluntary sales
- RECs that are expected to be retired on behalf of customer load in a different state where the utility serves customers (for either compliance or voluntary sales)
- RECs that are expected to be banked for future Oregon compliance
- RECs that are expected to be banked for compliance in a different state
- The approximate number of MWhs not associated with RECs reported above that are generated from renewable energy technologies

UM 2225 Order Summary/Rubric references: J.6(a)-(b)

Year	Portfolio40 Renewable Energy Credits (MWh) Retired for Oregon RPS compliance	Renewable Energy Credits (MWh) Retired for Oregon customer voluntary sales	Renewable Energy Credits (MWh) Retired in another state	Renewable Energy Credits (MWh) Banked for future Oregon RPS compliance	Renewable Energy Credits (MWh) Banked for future compliance in another state	Additional renewable generation (MWh)
2023	3,045,309	748,892	n/a	n/a	n/a	n/a
2024	3,159,254	2,030,532	n/a	787,939	n/a	n/a
2025	4,412,366	2,031,486	n/a	987,384	n/a	n/a
2026	4,564,405	2,042,553	n/a	4,361,737	n/a	n/a
2027	4,711,361	2,053,642	n/a	5,761,390	n/a	n/a
2028	4,888,474	2,069,373	n/a	7,237,299	n/a	n/a
2029	4,970,672	2,075,891	n/a	9,438,290	n/a	n/a
2030	6,593,765	2,087,049	n/a	9,343,955	n/a	n/a
2031	6,733,282	2,082,554	n/a	10,943,413	n/a	n/a
2032	6,900,748	2,082,757	n/a	11,844,167	n/a	n/a
2033	7,048,822	2,073,631	n/a	12,728,771	n/a	n/a
2034	7,239,407	2,069,203	n/a	13,703,051	n/a	n/a
2035	9,571,600	2,064,798	n/a	12,846,068	n/a	n/a
2036	9,874,322	2,065,061	n/a	13,927,231	n/a	n/a
2037	10,120,304	1,633,236	n/a	15,482,105	n/a	n/a
2038	10,390,233	1,403,058	n/a	16,720,965	n/a	n/a
2039	10,683,039	1,188,049	n/a	18,023,043	n/a	n/a
2040	12,236,736	1,191,304	n/a	18,200,878	n/a	n/a
2041	12,506,819	1,188,049	n/a	19,468,319	n/a	n/a
2042	12,778,443	1,188,049	n/a	20,045,803	n/a	n/a
2043	13,056,505	1,188,049	n/a	20,503,055	n/a	n/a
	sources: ɔligations by year from Portfolio Summary*hours in year	RECs of Community Solar PPA, GFI, GFI Phase II (Voluntary RECs)	n/a	RECs 5yrgenerated + Infinite RECs - retired RECs for Oregon RPS compliance - GFIs	n/a	n/a

Attachment 7. PGE 2023 CEP-IRP Round 1 Comments

Portland General Electric
121 SW Salmon Street • Portland, OR 97204
portlandgeneral.com

September 6, 2023

Via Electronic Filing

Public Utility Commission of Oregon
Attention: Filing Center
P.O. Box 1088
Salem, OR 97308-1088

Re: LC 80 – Portland General Electric Company's 2023 Clean Energy Plan and Integrated Resource Plan
Reply to Round 1 Comments

Dear Filing Center:

Enclosed for filing today in the above-referenced docket is Portland General Electric Company's (PGE) replies to Round 1 Staff and stakeholder comments on PGE's 2023 Clean Energy Plan (CEP) and Integrated Resource Plan (IRP).

PGE has sought to respond to each point of feedback included in Staff and stakeholders' Round 1 comments. Appendix A to PGE's response lists each comment and references the chapter in which it is addressed. PGE looks forward to engaging in further discussion of these topics and providing additional information on remaining questions at the upcoming LC 80 workshops on September 14th and 22nd.

Kristen Sheeran, PGE's Senior Director of Strategy Integration and Planning, leads PGE's CEP and IRP work. Please direct any questions or communications regarding these comments to: pge.opuc.filings@pgn.com.

Sincerely,

/s/ Riley Peck

Riley Peck
Senior Manager, Regulatory Strategy
Resource & Regulatory Strategy

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Introduction

PGE offers these Reply Comments in response to the Round 1 Comments filed by 13 different stakeholder groups in the LC 80 docket.[1] The Company appreciates the work that stakeholders have devoted towards PGE's 2023 CEP/IRP, and PGE has benefited from the reflections on the important considerations for both this and future CEP/IRP cycles.

While we have sought to respond to each question or suggestion (as summarized in **Appendix A: Comment and Response Crosswalk**), we have focused incremental analytical work on several high-priority areas where modeling refinements appeared to us to be able to most meaningfully inform consequential topics raised by stakeholders. These topics include transmission, energy efficiency, modeling considerations and portfolio analysis. As part of the new analysis responding to stakeholders' concerns, we have included a revised Preferred Portfolio which is provided in **Section 6.3**.

While there are many modeling improvements discussed below, PGE continues to believe that the CEP/IRP Action Plan aligns with the state's public policy goals and mitigates risks for customers while balancing affordability and emissions reduction during a highly dynamic period of change for our industry.

[1] A 14th was filed but were the same comments to which PGE responded in its 5/31 Round 0 comments.

Chapter 1. Decarbonization Plan

1.1 Clean Energy Plan

The Oregon Public Utility Commission Staff (Staff) has stated that PGE has not fully answered questions in long-term decarbonization planning.[2] It states that PGE has glossed over compliance obstacles and has not provided sufficient detail to allow the consideration of future options and trade-offs. Further, Staff requests additional discussion about the risk associated with the actions in the CEP/IRP, including the economic, technical feasibility, and implementation risks. Finally, Staff posed five questions to PGE that seek more detail on the Company's long-term decarbonization strategy.

PGE's response

PGE's 2023 CEP/IRP undertook a significant effort to balance system reliability, affordability for customers, and emissions reductions in the determination of what additional supply-side, demand-side, distributed energy resources, energy efficiency, and transmission resources would be required to meet the emissions targets established in HB 2021. Based on PGE's current long-term modeling processes, the plan articulates the general characteristics of incremental resources that will be needed over the remainder of the decade to reach the targets binding 2030 and beyond. To reduce emissions, PGE needs to replace thermal generation and purchases with non-emitting energy and capacity resources, while working with customers to shave or shift peak loads through energy efficiency, demand response, and management of flexible loads.

Absent HB 2021 there would still be significant resource need, driven by accelerating load growth, existing contract expirations, RPS obligations, and the requirement for small-scale renewables. However, a main finding from the 2023 CEP/IRP was that an unprecedented quantity of additional incremental generation resources and transmission capacity are needed to meet the 2030 target. Importantly, the CEP/IRP modeling also found that the resources needed to meet the 2030 target are economically and technically feasible.

Beyond 2030, and specifically to achieve the 2040 zero emissions target, the modeling shows that additional non-emitting resource technologies that are not currently economically or technically feasible will be needed to replace thermal generation as a backstop resource for reliability. This finding is consistent with numerous regional and national studies of pathways to deep decarbonization, net zero, or 100 percent emissions free targets. In the 2023 CEP/IRP, PGE was unwilling to speculate on which specific non-emitting technologies (e.g.,

[2] LC 80 Round One Comments of Staff at 7

hydrogen, nuclear, CCS, etc.) or combinations thereof and their costs will emerge over the next decade or more to advance decarbonization in the power sector. Instead, our longer-term modeling to 2040 detailed the key characteristics of those resources and the quantities that would be required to serve retail load with zero associated emissions while maintaining reliability and affordability.

Our decarbonization path modeled in the 2023 CEP/IRP is based on the best information that is known and available today and will almost certainly evolve as technologies, markets, and modeling improve. Importantly, the near-term resource actions proposed in PGE's Action Plan are the appropriate 'no regrets' next steps to meet the 2030 target and position our system for compliance with targets in 2035 and 2040, no matter how future technologies evolve. The resource need is so significant that the acquisition over the next several years of incremental non-emitting energy and capacity resources on our system is unavoidable under any future scenario of new technology development. None of the resource actions in PGE's proposed Action Plan preclude the future adoption of emergent technologies, including those that will enable PGE to aggregate and manage flexible loads to shave and/or shift peak energy needs. Our Action Plan proposes the near-term resource actions that balance cost, reliability, and emissions that best position PGE for success in achieving the 2030 target and targets beyond. Delaying action today for greater clarity on the development of future technologies that our modeling doesn't indicate are needed between now and 2030 will almost assuredly mean the company cannot meet the 2030 target.

With regards to the pathway to the 2030 target for which the commercial availability and costs of non-emitting technologies are better known, the modeling demonstrates that additional non-emitting energy and capacity generation resources are needed on PGE's system to reduce existing thermal generation and purchases with associated emissions sufficiently to achieve emissions targets. Coal from our contractual obligations to Colstrip will no longer be used to serve retail load by 2030. The modeling shows natural gas serving as a critical reliability backstop resource for our system, a need that was demonstrated most recently during the heat event the week of August 13th when our system broke another peak load record. Simply reducing existing thermal output to the required emission levels while not bringing on additional generation and capacity creates a system forecasted to be inadequate for reliability. These findings, again, are consistent with other studies of long-term decarbonization, which generally all suggest a large increase in non-emitting generation is required to meet emission reduction goals. Accordingly, it is a straightforward statement to say that many of the energy and transmission resources identified in the 2023 CEP/IRP, including utility scale wind, solar, and batteries, as well as distributed solar paired with storage, demand response, and energy efficiency are needed for HB 2021 compliance. That is why all these resources feature prominently in our proposed Action Plan.

Customer affordability must remain front and center as we decarbonize. Optionality and flexibility will be key as markets and the procurement environment evolve over time. This is

why the 2023 CEP/IRP is filed and updated on a regular cadence with the Commission, to account for changing economic and market conditions, technologies, and customer needs.

As discussed at great length in the CEP/IRP, PGE evaluated different scenarios for achieving the mandated emissions targets, including earlier or later decarbonization resource actions between now and 2030. Our modeling shows that those strategies, while consistent with meeting the emissions targets in HB 2021, pose higher risks and rate pressures for our customers. The linear path to emissions reduction detailed in the CEP/IRP best balances costs and community benefit with the likelihood of achieving the emission target by 2030.

To add an unprecedented amount of new non-emitting generation and transmission capacity under any of the evaluated scenarios, while expanding demand response, small-scale and community based renewable energy resources, and energy efficiency, however, is not without risk, as discussed in our CEP/IRP. The market's ability to site new resources and transmission; persisting supply chain constraints and challenging labor market dynamics; and the process time to buy, build, or otherwise secure access to new resources on our system is challenging. Our CEP/IRP is also forecasting load growth in a period of heightened uncertainty, because of new federal, state, and local policy drivers accelerating electrification and economic growth in key energy-intensive sectors in our service territory.

Climate impacts and weather uncertainty continue to challenge the reliability of the Western grid and the availability of hydro and wind resources. Market price volatility resulting from these and other dynamics challenge our ability to maintain affordability while we decarbonize. As other Western states decarbonize under similarly ambitious policy directives, the region will confront an increased scarcity of developable lands for new generation, transmission constraints and growing risks for resource curtailment. Some of these constraints can be alleviated by regional partnerships and collaboration and the growth and expansion of organized markets. PGE actively cooperates with BPA, CAISO, other entities, utilities, and energy suppliers across the West to support decarbonization goals and planning.

Despite these risks, we are pleased with recent successes since we filed the CEP/IRP in March: the acquisition of 475 MW of battery storage on our system and the recent announcement by BPA that will address some of our most immediate transmission constraints. We are taking all appropriate steps to accelerate the acquisition of resources and alleviation of transmission constraints and stand behind the path identified in the CEP/IRP as the right path to the emissions target for our customers. We are also engaging in regional discussions to improve the accounting and specificity of market purchases to ensure all non-emitting resources imported to our system are accounted for appropriately.

As the path we identified in the CEP/IRP is the least-cost, least-risk path to the emissions targets, deviations from that path based on what we know today imply increased cost and risk of the system becoming resource inadequate. To contemplate pursuit of other options would

require further discussion and direction from the Commission regarding the cost and reliability pauses referenced in HB 2021. Possible options include resources that the model did not select as cost-effective during this time horizon (e.g., pumped storage) or increased reliance on market purchases, which presents significant market price volatility and risks to our customers. Our modeling also shows that the aggregated sizes of the potential alternatives are insufficient to meet PGE's increasing need.

As mentioned above, there is no prudent path to the 2030 emissions targets on PGE's system that does not involve taking the near-term resource actions identified in the proposed Action Plan. Accordingly, this set of incremental resource additions can be viewed as 'no-regrets'. To increase the likelihood of acquiring the necessary resources on time and at the lowest possible cost for our customers, a more flexible acquisition process that can allow us to prioritize better market data with multiple acquisition windows to ensure we're acquiring the best value resources at the lowest cost will be very helpful, as we discuss in our July 17 filing in UM 2274.

Beyond 2030 we demonstrate, based on what we believe today, how much additional non-emitting energy and capacity will be needed to fully replace the role of thermal generation on our system. Key drivers such as technological advancement and market evolution will determine which resources will be most beneficial to replace them.

Turning to Staff's specific questions:

Will PGE's plan be feasible without future market interactions and market participation?

The incremental resources included in the Action Plan of this CEP/IRP are based on the current structure of market organization.[3] As discussed above, there are many unquantifiable risks included in PGE's CEP/IRP that could prevent the full realization of the plan; supply chains, labor availability, and development policy could each create significant headwinds to sufficient resource acquisition. Further, the economic impacts of those resource additions should be considered carefully. Currently, PGE projects a nominal 7.6 percent compounding average growth rate between 2024 and 2030, representing a ~37 percent increase in the real costs associated with generation resources. These projected cost increases present a risk to the plan's feasibility and addressing those cost increases, especially to lower-income and historically marginalized communities, will be a significant challenge.

[3] As both the impacts of market redesign on system requirements can vary widely and the wide uncertainty about potential future market developments, PGE's IRPs have generally not invested much attention towards potential market developments. The most certainty available today is the development of the WRAP, though there are many open questions about the methodologies as well as the integration of another planning jurisdictions (both discussed below in **Section 4.3.2.1, WRAP and CEP/IRP adequacy**).

It is possible that the development of a new and/or expanded market structure could more efficiently allocate resources and reduce the size of required incremental resource additions (and their associated costs). There is some analysis in the filed CEP/IRP envisioning these potential benefits, but they provide limited value as the results are highly sensitive to the input assumptions. PGE is actively participating in the development and expansion of organized markets and looks forward to working with Staff and stakeholders to adjust its long-term planning processes to fit the most expected market design.

> *Where are there junctures at which the Company might consider material changes in strategy that go beyond procurement volumes, for example adopting operating constraints on emitting resources, adjusting transmission requirements for renewables, joining an RTO, or other alternatives?*

PGE first notes that procurement targets will likely change between now and 2030 for two main reasons. The first, updated forecasts of system need, is the most intuitive, especially after the significant increase in estimated system need in the July 7th Addendum. However, the second, improved modeling capacity, could be equally important. The CEP/IRP modified what long-term planning tools it had available to incorporate appropriate emission accounting methodologies and address several new requirements and expectations. The realities of integrating variable generation will require additional improvements in PGE's modeling capabilities. Some of these improvements are discussed below in **Section 4.7.1, Hourly analysis of the Preferred Portfolio**, and some were discussed in the March 2023 IRP roundtable; however, further work is needed to develop a better understanding of the operational and financial challenges and opportunities of intermittent generation as the total MWs on PGE's system (and that of the region) increases. Additionally, changes to market structure could be a third driver of a change in resource need if they materialize.

PGE continues to evaluate transmission requirements for its owned and contracted off-system generation resources. The Company notes it has been responsive to stakeholder and Commission input in recent procurements reducing levels of required firm transmission. However, PGE notes that adjusting transmission requirements for renewables can increase risk to customers. As noted below in **Section 2.1, Comprehensive transmission comments**, as part of WRAP compliance obligations PGE is expected in the day of operations to have 100 percent of energy delivered to load on firm transmission. The reduction of expected capacity contribution to PGE's system as well as to the WRAP could decrease the cost-effectiveness of certain projects. To mitigate this risk PGE will continue to work with regional peers and stakeholders to establish risk-adjusted no regrets strategies, such as accelerating new build of transmission, seeking regional portfolio diversity, exploring an RTO, and taking the highest-value transmission products when they're available.

Operational limits on thermal generation do not change PGE's resource strategy. The modeling assumes a fixed carbon budget from thermal generation consistent with the HB 2021 emissions targets. Holding thermal generation fixed without substituting that power on the system with sufficient non-emitting energy and capacity resources would lead to a system that is resource inadequate. Hence, PGE's strategy must include replacing thermal generation and purchases with sufficient non-emitting energy and capacity resources. The specific resources or combinations therein that offset the need for thermal generation will be determined primarily through competitive bidding processes. But there is no physical path to serving our customers' energy needs without replacing thermal generation with non-emitting resources. Energy efficiency, demand response, and aggregation and management of flexible loads will help shave load and reduce peak energy needs; but no combination of these resources is sufficient to offset all the thermal capacity currently serving our customers and to meet anticipated load growth. Again, these findings are consistent with other studies of long-term decarbonization, which generally all suggest a large increase in non-emitting generation is required to meet emission reduction goals.

However, Staff's question asks about modifications in PGE's decarbonization strategy that go beyond updates to procurement volumes mentioned above. This question is unanswerable, as PGE does not have the foresight to know when, where, and why conditions will change to warrant a different strategy; if PGE knew where these junctures sat, it would already have changed its plan to address them. PGE, the Commission, and stakeholders can re-evaluate PGE's strategy when the next CEP/IRP is filed. In the interim, PGE proposes to take the no-regrets near term actions proposed in the Action Plan and we will continue to look both internally (e.g., changes in operational requirements) and externally (e.g., market redesign) to address challenges to affordability, reliability, and decarbonization.

> *What information will the Company use to determine whether a change in course may be warranted? Will the Company adjust its strategy based only on the progress of procurement, or will PGE examine additional data, like actual GHG emissions, power costs, load forecasts, and load forecast uncertainties, as the Company executes its strategy?*

The company will have to acquire sufficient non-emitting generation to maintain system adequacy while reducing dependence on thermal generation to meet retail load. In its long-term planning processes, PGE already incorporates GHG emissions, power costs, load forecast uncertainties into its analysis. The Company expects to continue updating and incorporating this data going forward. Additionally, new data and information will inform future planning assumptions, including that which we learn through responses to our RFP. Our ability to acquire on a least-cost, least-risk basis, as well as any significant changes in technology cost or availability could modify PGE's preferred resource mix in the future.

Affordability for customers and system reliability remain PGE's priority as we decarbonize. If risks to system reliability or unsustainable rate pressures for customers materialize, PGE will invite further discussion and direction from the Commission regarding the cost and reliability pauses referenced in HB 2021.

> *Under what circumstances could each of PGE's planned actions result in poor outcomes for customers?*

PGE's customers have routinely expressed their preference for an energy system that is reliable, affordable, and increasingly decarbonized. Accordingly, any action that reduces any of those three main components could be considered a poor outcome to customers. PGE sees very few opportunities for unilateral actions the Company can take to improve one or more components without negatively affecting another. For example, incremental generation resources cost money, which while increasing decarbonization and reliability, reduces affordability. However, the opportunities to partner with our customers on flexible grid solutions, including demand response, energy efficiency, managed vehicle charging, solar paired with batteries, and distributed standby generation can help reduce our customers' overall energy expenditures, lower GHG emissions, and provide needed flexibility and capacity to the grid. That is why these resources factor more prominently in this CEP/IRP and proposed Action Plan than in years past.

In this CEP/IRP, PGE did not model any evaluation of reducing system reliability, as the Company believed its long-term plan should ensure a consistent approach to resource adequacy. As a side analysis PGE did consider some variations in likelihood the company was able to meet 2030 emission reduction targets. This analysis did not influence the Action Plan, as the Commission directed PGE to create a plan that achieved emission targets under expected average conditions.[4] Accordingly, PGE created a plan that achieved reliability and emission reduction targets at the lowest expected costs. To determine the economic feasibility of this plan, a more salient question to both PGE and its customers would be to ask what potential rate impacts customers would accept to have a reliable and decarbonized system. PGE has been transparent in providing all projected cost information and is willing to continue working with Staff and stakeholders to assess that challenge.

Finally, while it is impossible to create a portfolio that is devoid of risk, PGE's planned actions are designed to be robust to a wide range of future circumstances while balancing the inherent tradeoffs between key outcomes for customers. There is substantial uncertainty inherent in forecasting of energy prices, resource costs, supply chains, need, weather, etc. That is why portfolio analysis is conducted across many future conditions to capture the effects of a wide range of potential future outcomes. PGE's Action Plan represents the best combination of cost, risk, community benefits and emission reductions, as determined by the

[4] See Commission Order No. 22-446: https://apps.puc.state.or.us/orders/2022ords/22-446.pdf

insights gained through portfolio analysis and the construction of the Preferred Portfolio. The goal is to provide the best possible combination of outcomes for customers across the range of these areas while balancing the tradeoffs between them.

Did PGE consider but exclude any actions because of their potential for adverse impacts to customers under one or more future scenarios?

Yes, PGE considered many actions that were eventually excluded from the Preferred Portfolio due to their potential for adverse impacts to customers. As mentioned above, portfolio analysis in the CEP/IRP was designed to consider which actions should be taken to provide maximum benefit to customers while meeting decarbonization requirements and maintaining a reliable system. This was done by designing groups of portfolios to test outcomes regarding key planning questions. PGE considered both faster and slower rates of decarbonization and found that neither could provide a better balance of the tradeoffs between cost and GHG-reductions than a linear glidepath. PGE considered including additional quantities of EE above and beyond what ETO forecasted as cost-effective, however, the Company elected to exclude them in the Preferred Portfolio due to their near-term cost impacts and uncertainty regarding how recent historic increases in federal, state, and local funding for energy efficiency in our service territory may shift the market and lead to new opportunities for our customers to access these energy saving opportunities at lower cost. PGE considered not pursuing transmission expansion and upgrades, but portfolio analysis strongly suggested this would increase both costs and risk as well as the reliance on transmission capacity beyond what is forecasted to be currently available. The consideration of lower quantities of CBRE acquisitions was also evaluated but found to increase cost and risk while also decreasing community benefits. PGE will continue to work with Staff and stakeholders to determine the most appropriate questions in long-term planning and will seek to design its portfolio analysis to answer them.

Chapter 2. Transmission

2.1 Comprehensive transmission comments

OPUC Staff submitted multiple near-term transmission questions and comments regarding South of Allston (SoA) congestion relief and Bethel-Round Butte upgrades. Staff is concerned that these two near-term Action Plan items are not supported by analysis.[5]

Specific to SoA congestion relief, Staff writes that PGE "has not provided very much analysis" to demonstrate that the benefits of the SoA upgrade outweigh the costs. They note that the

[5] LC 80 Round One Comments of Staff at 32-34

CEP/IRP only compares this upgrade to a generic variable energy resource, and that this comparison is arbitrary given the generic nature of that resource. They ask "if and when" PGE can provide more specific cost/benefit analysis to determine what upgrades should be invested in and/or what alternatives should be pursued.

Staff asks if PGE has considered different approaches to relieving SoA congestion, including solutions like batteries and/or multiple option solutions, and interpret the congestion relief Action Plan item to be "inclusive of a range of possible solutions." Staff also asks if the SoA congestion relief is feasible by 2030, and if not, what alternatives exist. Lastly, Staff asks if the SoA upgrade is driven partly due to load-service needs (as opposed to renewable procurement), and if yes, how the costs and benefits of the upgrade changed with the Addendum load growth assumptions.

Related to the Bethel-Round Butte Action Plan item, Staff notes that they are unclear on the amount of transmission (in MW) this upgrade would provide and are unclear on its costs. They are concerned that this transmission option has not been incorporated into portfolio analysis, and that PGE has not "provided the information needed to confirm that the costs of this type of investment is supported by PGE's analysis." Staff also asks if the Preferred Portfolio would change if the costs and benefits of this option were included in modeling. They reiterate that like SoA congestion relief they need more cost/benefit analysis, including analysis on thermal operations and GHG emissions, to "determine the investment reasonable."

OPUC Staff asks PGE to explain the CEP/IRP long-term transmission strategy, noting that the Action Plan does not provide insights into how regional transmission resources will be acquired. They ask for PGE to improve transmission modeling for future planning work, and to explain how the transmission strategy protects against risks, what those risks are, and how PGE will use transmission rights excess to load service to benefit customers.[6]

Regarding regional transmission, Staff would like to know when PGE will know if the Wyoming and Desert SW transmission proxies are feasible within the timeline of the Preferred Portfolio (553 MW of resource acquired by 2029, 800 MW by 2030). If they prove to be infeasible, Staff asks what alternative resources and/or transmission strategy exists. Staff is also concerned that the 2030 reliance on Wyoming and Desert SW transmission increased from 255 MW in the filed IRP to 800 MW in the Addendum, and notes that PGE has not addressed the risk "that it may have severely underestimated or overestimated future transmission needs within the plans."

NewSun Energy and Energy Advocates also raised concern regarding the transmission proxy development timeline. NewSun states that if PGE is unable to secure transmission rights or

[6] LC 80 Round One Comments of Staff at 30-31, 34-36

partnerships on existing projects that a new transmission build could take "at a minimum" 10 years to construct. They are concerned that reliance on the transmission proxies could lead to under-procurement of other resources should the proxy be unavailable.[7] Energy Advocates notes that proxy transmission to Wyoming and The Desert SW appears in the Preferred Portfolio as early as 2029, which is at odds to PGE's statement that "…new significant transmission projects can take 15-20 years to develop..."[8]

Lastly, Staff notes that the transmission strategy includes around 15,000 MW of transmission rights in 2040 while PGE's peak load reaches roughly 6,000 MW. They state that this strategy is "not sustainable" and prioritizes avoiding transmission-related curtailments over "all other cost and risk considerations." Staff asks how those levels of transmission rights will benefit customers, and what other strategies PGE could examine to reduce costs to customers and to avoid "over-constraining BPA's transmission inventory." Staff notes other strategies exist, including using short term firm or non-firm transmission, sharing transmission rights of existing resources, joining an RTO, securing transmission to less constrained points, and limiting rights "…across constrained paths based on what is needed for load service…" They suggest PGE explore, potentially via zonal dispatch modeling, alternative transmission strategies in the next CEP/IRP and identify the costs, risks, emissions, and community impacts of those strategies.

AWEC finds PGE's transmission modeling to be generic in nature and thus unsupportive of investment plans.[9] They note that the resources unlocked by SoA congestion relief have transmission paths that should be differentiated in the analysis and are skeptical that SoA congestion relief would benefit all Northwest proxy resources like solar in McMinnville or Christmas Valley. AWEC also finds PGE's transmission Action Plan items to be unactionable, noting that the amount of transmission selected by the CEP/IRP did not increase in the Addendum despite the increased resource need. They are unsure if Commission acknowledgment of the Action Plan would allow further study of transmission or transmission resource acquisitions.[10]

RNW encourages PGE to perform a more detailed examination of transmission options, in part due to the rapid development schedule in the CEP/IRP, and in part to improve offshore wind analysis.[11] They find that PGE's transmission modeling is overly generic and note that the specific upgrades available (SoA and Bethel to Round Butte) favor resource development in those areas, and that PGE has not demonstrated which transmission projects are best since that involves determining which geographic areas or technologies are of highest resource

[7] LC 80 Round One Comments of NewSun at 6-7.
[8] LC 80 Round One Comments of Energy Advocates at 10.
[9] LC 80 Round One Comments of AWEC at 9-10.
[10] LC 80 Round One Comments of AWEC at 11-12
[11] LC 80 Round One Comments of RNW at 30-31.

value.[12] They state that "Oregon offshore wind is a viable alternative to SoA and Bethel to Round Butte because its energy can be delivered to Portland without these specific transmission upgrades," and that based on a NorthernGrid study that offshore wind would alleviate SoA congestion.[13] Finally, they ask for PGE to consider merchant transmission projects in the CEP/IRP and to actively consider non-wires solutions for addressing transmission congestion.

Energy Advocates would like a transmission workshop held to discuss the details of the CEP/IRP transmission assumptions, with a focus on SoA congestion relief and the Wyoming and Desert SW proxies. They state that the transmission information provided in the CEP/IRP goes beyond what was discussed during the development of the CEP/IRP, and that the workshop could help stakeholders better understand the transmission options.[14] NewSun Energy recommends that the Oregon PUC hold a transmission workshop on upgrades to the BPA system. They are concerned that the transmission service requests (TSRs) pointing at PGE are no longer available. They also ask for a different methodology to determine the availability of firm versus condition firm transmission rather than assuming that confirmed TSRs are firm and those in study are conditional firm. Lastly, NewSun is concerned that the timeline for BPA transmission upgrades in the CEP/IRP is unrealistically quick.[15]

PGE's response

PGE appreciates stakeholder input noted above and the opportunity to explain how the transmission resources in the Action Plan fit into its wider transmission strategy as the company moves towards the emission reduction targets established in HB 2021. Finding a means to increase capacity over the South of Allston flowgate and the upgrading of the Bethel-Round Butte line from 230 kV to 500 kV are critical to acquire sufficient generation. Additionally, the company is continuing its work planning for cost effective, safe, and reliable load service by advancing nearly twenty transmission projects needed to bolster system reliability and bring incremental transmission capacity to and through PGE's service territory to serve growing loads. Projects currently included in PGE's local Transmission Plan span both projects that enhance regional transmission reliability and expand interface capacity with BPA, as well as projects that are designed to meet high concentrations of new load and enhance reliability on specific parts of PGE's system. These specific projects are listed below in **Table 1**.

[12] LC 80 Round One Comments of RNW at 40-41
[13] LC 80 Round One Comments of RNW at 41 & 43
[14] LC 80 Round One Comments of Energy Advocates at 8.
[15] LC 80 Round One Comments of NewSun at 7-8.

Table 1. Summary of regional enhancement projects

Title	Purpose/scope
Harborton Reliability	Reconfigure the system to reduce exposure and provide a stronger source to Northwest Portland 230 and 115 kV systems. Expected completion 2026.
Horizon-Keeler BPA #2 230kV	Accommodate load growth in Hillsboro by constructing a new bay at BPA's Keeler Substation. Expected completion 2024.
Willamette Valley Resiliency	Strengthen and increase the resiliency of PGE's system in the Central portion of PGE's territory, north of the Salem region. Expected completion 2028.
Pearl/Sherwood 230kV Reinforcement	Mitigate the overloading of the McLoughlin-Pearl BPA-Sherwood 230 kV line caused by the loss of the Pearl BPA-Sherwood 230 kV line. Expected completion 2026.
Hillsboro Reliability	Significant upgrades to prepare for load growth in the Hillsboro area. Expected completion 2027.
Horizon Keeler BPA #1 230 kV Reinforcement	Mitigate overloads seen on the Horizon-Keeler BPA #1 230 kV line due to Hillsboro-area load growth. Expected completion 2027.
Murrayhill-Sherwood #1 and 2 230 kV Reconductor	Mitigate overloads caused by the loss of other 500 and 230 kV sources during south-to-north flow conditions in the Beaverton/Hillsboro area. Expected completion 2027.
Murrayhill-St. Marys #2	Mitigate overloads caused by the loss of other 500 and 230 kV sources during south-to-north flow conditions in the Beaverton/Hillsboro area. Expected completion 2027.

Additionally, PGE has identified projects that are included in the OATT Attachment K Local Transmission Plan and are designed to enhance local system reliability, displayed below in **Table 2**:

Table 2. Summary of local system reliability projects

Reedville Substation Rebuild	Groveland Substation Project
Memorial Substation Project	Glencullen Rebuild & Cedar Hills Breaker Project
Tonquin Substation Project	SE Portland Conversion Project Holgate Substation
Kaster Substation Project	Mt Pleasant Substation Project
Redland Substation Project	Scholls Ferry Substation Project

Further, PGE is also collaboratively investigating with its regional peers how transmission and resource planning processes should be reformed to create an actionable regional transmission plan the evaluates the regional transmission system using a 'one-utility' approach.

South of Allston

PGE has been experiencing increasing load growth across our territory, with a high concentration in the Portland Metro area that includes Hillsboro. To serve that load PGE needs to increase the transfer capability to and through PGE's system to discrete load service areas. Adding capacity to the South of Allston flowgate does this. An upgrade to the South of Allston flowgate that brings incremental transfer capability to and through PGE's system also benefits customers through supporting reliability in the Portland and Hillsboro area.

There is not a location on the BPA system, or beyond, to site generation that does not have an impact on South of Allston flowgate. This is because of Power Transfer Distribution Factor (PTDF), which refers to the distribution of power flows on the networked transmission system. PTDF applies broadly across the regional transmission system. For PGE, because of the topology of the regional transmission system, there are effectively no locations within the western interconnection, whether inside BPA's footprint or beyond, where new incremental transmission service can be added that delivers to PGE that doesn't measurably impact flows on the South of Allston path. With South of Allston being fully subscribed, a transmission solution to bring incremental transmission capacity to South of Allston is necessary to enable incremental transmission service directed to PGE. Adding transmission capacity provides an opportunity to meet HB 2021 requirements. Additionally, studies are now demonstrating that upgrades to South of Allston are necessary to deliver enough power to serve the northern part of PGE's service area, which includes Portland and Hillsboro. This means the company must increase the total transfer capability to serve requested load in Hillsboro/Portland area.

The recently announced BPA projects from their TSEPs help increase deliverability to PGE's general service territory, but it is not possible to discern exactly how much capacity BPA's projects will bring that directly benefit PGE customers with the currently available information. When this information becomes available, we will incorporate it into our models and ensure our plans are still the best for choices for customers.

PGE has not recently considered alternative methods to alleviate South of Allston congestion (such as batteries or non-wires alternatives) because the known constraint in the studies is hundreds of MWs and can last greater than 12 hours. Figure 66 in the filed CEP/IRP shows that the expected deficit in 2030 is more than 1,500 MW, and due to the volume and timing there simply is not an economically and operationally viable alternative today. PGE believes that if work began immediately on the South of Allston flowgate the increased capacity could be available by 2030.

Bethel-Round Butte

The Bethel-Round Butte component of the Action Plan aims to study optionality to develop a project that would upgrade the Bethel-Round Butte 230 kV line to 500 kV. The project would increase transmission capacity from resource-rich areas of central and southern Oregon to

PGE's system. The project also increasingly connects PGE's load service territory directly with the Northwest AC Intertie (NWACI), the 500 kV transmission system that connects Oregon and California. PGE is a co-owner of the NWACI along with BPA.

The Bethel-Round Butte line is part of the Cross Cascades South which is considered a WECC defined path. The Cross Cascades South Path is the same as BPA flowgate known as West of Cascades South (WOCS). The WOCS flowgate is currently known to be constrained and is viewed by some commenters in this docket as PGE's biggest obstacle to delivering new resources to company loads. Currently, the Bethel-Round Butte line is considered a de minimis component of the WOCS flowgate. An upgrade of the Bethel-Round Butte line will increase WOCS transfer capability for the purposes of serving PGE's system loads. It should be noted that due to the geographic location of the Bethel-Round Butte line, energy deliveries that use new incremental line capacity could allow PGE to avoid the constraints of multiple BPA flowgates that exist near the border between Oregon and Washington.

Together with the Confederated Tribes of Warm Springs (CTWS), an application has been submitted to the US Department of Energy (USDOE) seeking up to $250 million dollars in grant funds under the USDOE's Grid Resilience and Innovation Partnerships Program. If the grant application is successful, PGE and the CTWS will partner on the development of the project. Along with PGE's increased access to resources and energy markets, the project would provide the CTWS economic development opportunities that otherwise would not exist. PGE currently lacks the detail that parties are requesting as the Company has not yet started in earnest studying the project. There are many variables still to be determined. PGE plans on conducting the analysis over the next few months.

Transmission in CEP/IRP portfolio analysis

PGE appreciates the feedback on the need for improved transmission analysis as part of future planning processes. For the need for greater granularity on paths that would alleviate SoA congestion and increase transfer capability over the Bethel-Round Butte path, we note that the Action Plan requested that both options should be further explored via power flow studies and economic analysis to meet the portfolio need identified in the CEP/IRP. PGE plans on conducting this analysis in the coming months, and we expect that this additional analysis can provide more granular detail on the potential capabilities of transmission upgrades and the more precise cost/benefit tradeoffs.

Regarding the proxy Wyoming and Desert Southwest transmission options being available too quickly, PGE agrees with that statement if the assumption is that any new rights introduced into the portfolio are based on beginning a new resource build today. PGE's Action Plan assumes that the company can and will explore all options to add incremental rights, including acquisition of rights on existing regional systems, and/or potential participation in new inter-regional transmission builds that are already underway and

scheduled to come online before 2029. PGE stresses that these two options are proxy representations and that other transmission options may be explored as well.

It is also worth noting that the portfolio selections, both in the Action Plan window and later in time, are proxy-based, are intended to solve system-based need to ensure operational reliability. For example, Staff notes that 15,000 MW of incremental transmission rights in 2040 seems like an unsustainable number, however as part of WRAP compliance obligations, PGE is expected in the day of operations to have 100 percent of energy delivered to load on firm transmission. Reliance on non-firm leaves PGE at risk of increased curtailment, increased loss of load probability, and sanctions for non-compliance. When a transmission loading relief (TLR) is issued (curtailment order), non-firm transmission is the first to be curtailed, consistent with NERC e-tag priority, to alleviate congestion on the flowgate. At the same time, BPA stops all sales of transmission across that flowgate. For the South of Allston flowgate, there is not a generation location on the BPA system that has a non *de minimis* impact on the South of Allston flowgate, meaning the only alternative PGE must resupply the curtailed energy is from on-system generation. TLR events are most likely to occur during high load times, when all on-system generation is being dispatched to serve load with little to no capability to backfill non-firm curtailments and puts PGE at greater risk of having to shed load. Also, there are limited quantities of firm ATC in the short-term time horizons. Conditional firm products have priority access to short-term ATC, meaning conditional firm transmission service reservations (TSRs) are firmed up with any short-term ATC, given the volumes of conditional firm service, BPA releases limited amounts ATC in the short-term market.

Regarding the comments on offshore wind generation, and its impact on South of Allston transmission, PGE agrees that in general, import of power in the Southern Oregon area appears to have a minimal impact on the South of Allston flowgate. The BPA Power Transfer Distribution Factor calculator (displayed below in **Figure 1**) estimates that for every 100 MW injected at Gold Beach (an offshore wind proxy location), South of Allston would experience 7.5 MW of additional congestion, which may be considered a *de minimis* impact. BPA notes that the PTDF calculator on their website should be used for indicative purposes only and that all requests for long-term firm transmission capacity must be studied. It is worth noting that this calculator does not yet include the modifications necessary to account for the new BPA flowgates that are currently being implemented and impact PGE, including the North of Pearl flowgate (NOPE) and the North of Grizzly flowgate (NOG). NOPE is a west-to-east cutplane flowgate located between Sherwood and Wilsonville and significantly impacts PGE's ability to delivery power to Portland and Hillsboro. NOG is a new flowgate that will be implemented on the NWACI north of PGE's Bethel-Round Butte line. The successful development of a Bethel-Round Butte upgrade project could allow PGE to avoid NOG impacts and the successful development of a South of Allston project could help mitigate impacts from the implementation of NOPE.

Figure 1. BPA Power Transfer Distribution Factor calculator

			Zone	kV	Owner Name
Evaluated Source:	GOLDBEACH115		Western Oregon	115	Bonneville Power Admin
Evaluated Sink:			PAC:PTLD	230	PacifiCorp - West
Request MW:	100				
Posted 6/1/23					
Sub Grid Constrained Area:		PORTLAND AREA			
PTDF #:	40475	45301			

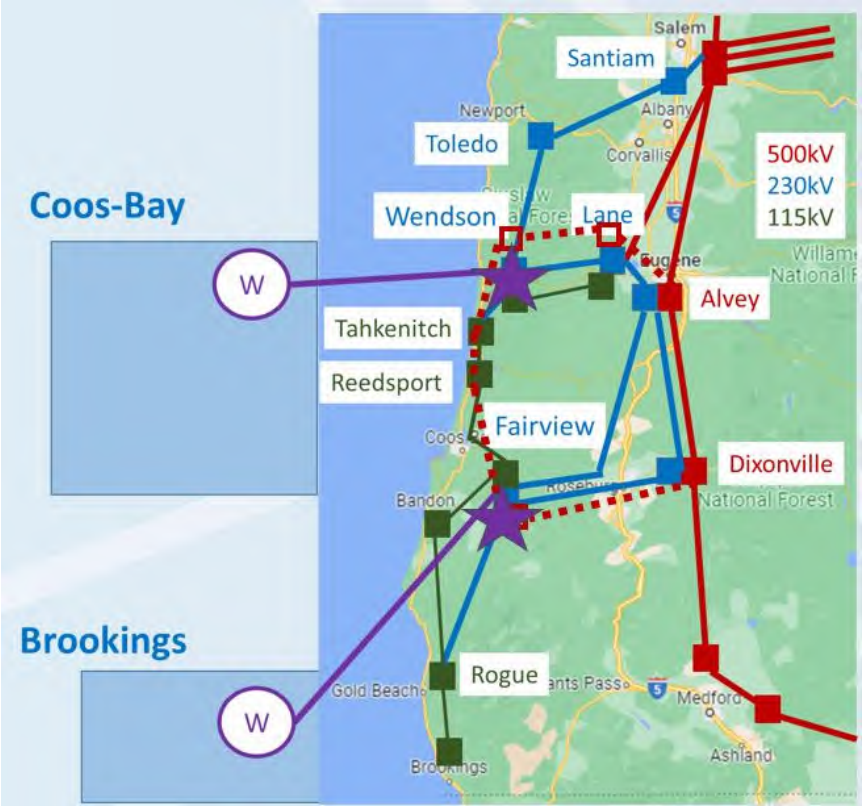
Flowgate	Source	Sink	% Impact	MW Impact	Result
CROSS CASCADES NORTH E>W	-0.1955	-0.2642	6.9%	6.9	Potential LTF
CROSS CASCADES SOUTH E>W	-0.5196	-0.6736	15.4%	15.4	Study for CFS
NORTH OF HANFORD N>S	-0.5992	-0.5277	-7.2%	0.0	Potential LTF
RAVER-PAUL N>S	-0.1271	-0.1739	4.7%	4.7	Potential LTF
SOUTH OF ALLSTON N>S	-0.2018	-0.2757	7.4%	7.4	Potential LTF
WEST OF JOHN DAY E>W	-0.0697	-0.2598	19.0%	19.0	Potential LTF
WEST OF SLATT E>W	-0.1906	-0.1355	-5.5%	0.0	Potential LTF
WEST OF LOWER MONUMENTAL E>W	-0.0586	-0.0580	-0.1%	0.0	Potential LTF
SOUTH OF CUSTER N>S	-0.0022	-0.0059	0.4%	0.4	Potential LTF
NORTH OF ECHO LAKE S>N	0.0441	0.0464	-0.2%	0.0	Potential LTF
WEST OF MCNARY E>W	-0.1345	-0.1259	-0.9%	0.0	Potential LTF
WEST OF HATWAI E>W	0.0551	0.0418	1.3%	1.3	Potential LTF
NORTH OF GRIZZLY N>S	-0.2119	-0.0022	-21.0%	0.0	Potential LTF

0.##### Indicates that impact may be considered de minimis.

Per the ongoing NorthernGrid Economic Study Request that examined offshore wind impacts on the regional transmission system, significant additional transmission investments would be required to accommodate any large injection of offshore wind generation. The study identified that for 3 GW of new wind, hundreds of miles of additional 500 kV transmission lines would need to be built. Much of the required right-of-way would pass through the sensitive Rogue River Valley and other sensitive and scenic coastal areas. The expected cost of this required transmission infrastructure is significantly higher than the contemplated PGE transmission projects. It is important to remember that the economic study was for economic dispatch evaluation purposes only and did not contemplate the full scope of analysis necessary to evaluate interconnection and delivery to specific load centers. It is expected that interconnection and transmission service delivery analysis studies would identify significant additional costly transmission upgrades.

Additionally, the NorthernGrid study utilized a 2030 delivery date for the projects, which would not meet PGE's needs and is likely not feasible. The project would also primarily require BPA and PacifiCorp to fund and construct the upgrades, with significant portions needing to be located in new or expanded rights-of-way. PGE will have little control or influence of project timelines. In addition to transmission upgrades by BPA and PacifiCorp, land-based coastal infrastructure necessary to deploy offshore wind will need to be developed. PGE understands that there is not sufficient port or highway infrastructure currently in place in Oregon necessary to deliver, assemble, and make ready offshore wind equipment for deployment. **Figure 2** displays the interconnection upgrades necessary for the development of offshore wind.

Figure 2. Necessary interconnection upgrades for offshore wind



Regarding the suggestion of a potential transmission-specific workshop, PGE is not convinced that is the most productive use of time. The Company has spent substantial time in the IRP roundtable meeting series describing transmission planning, and we encourage any participants who missed those sessions to rewatch the videos available on our website as time allows. PGE periodically holds 'office hours' throughout the comment period, as opposed to additional workshops. We recommend bringing these questions to the office hours sessions. If these topics cannot be sufficiently addressed in that forum, the Company is committed to working with parties to determine how to address them. Earlier transmission focused workshops covered material at a rudimentary level and did not lead to any actionable changes in transmission planning or operations.

Regarding the comment that the analysis is overly generic, the transmission analysis in the PGE IRP focuses on transmission paths that are (1) impactful to PGE's ability to import generation (2) known to have existing congestion and (3) projected to experience increasing congestion due to changing generation and load patterns. The overall transmission system is networked, and generation impacts at one location affect flows across the network. As additional generation is constructed in the Western Interconnect, PGE will continue to assess how these changing generation patterns impact potential transmission bottlenecks and identify necessary transmission investments accordingly.

2.2 Conditional firm transmission modeling

RNW, via a report written by Grid Strategies, again asks PGE to rethink the modeling of conditional Firm 200hr transmission and that a more detailed curtailment analysis could lead to "innovative solutions to transmission congestion."[16] They provide an updated version of their conditional firm study that they submitted with their Initial Comments.[17] They find that zero hours of curtailment should be used for modeling conditional firm 200hr transmission in the adequacy model. However, arriving at that result required them to assume that curtailments are reduced via a 4-hour 2,400 MW battery. The 4-hour 2,400 MW battery represents "the installed storage capacity between PGE and PacifiCorp West."[18]

Grid Strategies responded to the comments PGE provided in its Initial Comment Response. They agree with PGE's comment that not all resources should use conditional firm transmission due to "uncertainty about the location and quantity of the regional expansion of renewable and storage resources", but then restates that BPA has never curtailed conditional firm transmission and again finds that zero hours of curtailment should be modeled for conditional firm transmission.[19] They do not think studying the South of Alston transmission path is necessary and still think the West of Cascade South path is PGE's key transmission constraint point. Grid Strategies agrees that a power flow study is the best modeling approach and suggests that PGE conduct one, that insufficient data are available for a N-1 analysis, that incorporating load growth into the analysis is unnecessary, and that accounting for renewables built by other Northwest utilities (outside of PacifiCorp and PGE) is unnecessary.[20]

PGE's response

PGE appreciates the work that both RNW and Grid Strategies have done to contribute to the transmission picture in Oregon. While additional analysis can help to clarify the overall picture, PGE has concerns with the methodology employed to determine that zero hours of curtailment for BPA Conditional Firm products should be the base case for future analysis, and we caution against extrapolating any near-term decisions based on the analysis.

Primarily, the study relied on the assumption that there will be 2,400 MW worth of 4-hour batteries installed that could offset the need for curtailment by shifting transmission in a way that would alleviate congestion. PGE notes that this would likely be a significant resource addition effort alone. Additionally, the study assumed that South of Allston would be

[16] LC 80 Round One Comments of RNW at 30-31
[17] LC 80 Round One Comments of RNW at Attachment D
[18] LC 80 Round One Comments of RNW at Attachment D
[19] LC 80 Round One Comments of RNW at Attachment D
[20] LC 80 Round One Comments of RNW at Attachment D

upgraded, meaning that the zero-curtailment case would hold only if PGE were to pursue at least one of the actions listed in the 2023 CEP/IRP Action Plan. Finally, the study notes that "newer technologies and practices… can be used to respond to system contingencies." PGE agrees that future technology and process innovation will help make transmission planning nimbler and more precise, but that future state cannot be the basis of near-term modeling that could impact PGE's operational window.

PGE does not disagree with Grid Strategies' findings necessarily over a 20-year time horizon and under the specific conditions put forward (South of Allston upgrade in place, 2,400 MW of incremental 4-hour battery, and new technologies). However, we note the risk of making operational decisions (such as assuming zero curtailment for the purposes of actual resource acquisition) based on the study put forward. PGE looks forward to continued collaboration with staff and stakeholders to assess the right operational modeling needs as we work to maintain reliability and progress toward the decarbonization targets.

PGE is also concerned about Grid Strategies' choice of load growth assumptions. For context, the PGE Corporate Forecasting expects 1-in-10 loads to increase from 4,456 MW in 2023, to 5,166 MW in 2030, to 6,362 MW in 2040. If the Grid Strategies analysis failed to consider these (very reasonable) increases in forecasted load, it would miss significant impact that this additional load has on regional transmission paths, including SOA and WOCS. It should be noted that PGE's load during the 2021 heat dome event exceeded 4500MW on two occasions in August of 2023. PGE believes the analysis should consider WECC-wide load and generations; simply looking at PGE and PAC does not appropriately estimate all the changes in flows we are seeing across BPA's network. PGE does not believe the study provides sufficient evidence that the capacity contribution should be the same for LTF and CF transmission.

2.3 Proxy Transmission Cost

Energy Advocates would like more information on the costs used for the proxy transmission projects to Wyoming and the Desert Southwest. Specifically, they would like to know if the prices from the 2018 report have been updated to reflect current prices, including if the prices have been adjusted for inflation, and if not, if PGE is taking potentially higher prices into consideration.[21] NewSun Energy also has concerns regarding the cost of the generic proxy resources, noting that PGE has not explained how they were developed and questions if they are reflective of costs found on the market. They cite the study PGE used to develop

[21] LC 80 Round One Comments of Energy Advocates at 9-10

costs that notes that transmission costs can be "substantially higher if substations are needed" and if right-of-way costs are higher.[22]

PGE's response

PGE has not done additional work on the transmission proxy costs since filing the CEP/IRP. Rather, the company continues to rely on the 2018 report "Relative Costs of Transporting Electrical Chemical Energy" to form the basis of the transmission proxy costs in the CEP/IRP. [23] To formulate the transmission proxy costs, the costs outlined in the study are adjusted for inflation using PGE's long-term inflation rate available at the time of the analysis.

As explained previously, PGE developed the cost assumptions by relying on the study cited above, where PGE converted the costs associated with a 500 kV single circuit transmission line expressed in a $/MW-mile metric. That cost, and the estimated distance of the proxy transmission paths, form the basis for the capital costs for the transmission proxies. PGE's historical O&M costs associated with our existing transmission portfolio are extrapolated and included as well. PGE's historical O&M costs associated with our existing transmission portfolio are extrapolated and included as well. The prices do not incorporate any further adjustments as the costs are intended to reflect a generic proxy resource. Market transmission costs can vary depending on factors like terrain, environmental considerations, right-of-way costs, substation costs, and so on. These nuances were not intended to be captured in this high-level, directional analysis. PGE notes too that increases to these cost estimates would only affect projections of future costs and would not likely change resource buildout choices.

2.4 Additional transmission options

Grid United suggests that the two proxy transmission expansion resources modeled in the CEP/IRP do not capture the full suite of interregional benefits PGE could capture through new transmission to other organized markets. They request that PGE include an interregional proxy resource that would provide additional benefits in additional analysis as part of the 2023 IRP Update or a future IRP.[24]

[22] LC 80 Round One Comments of NewSun at 6-7
[23] Saadi, Fadl H, et al. "Relative Costs of Transporting Electrical Chemical Energy." Energy & Environmental Science, Energy & Environmental Science, no. 3, 29 Jan. 2018, pp. 469–475.
[24] LC 80 Round 1 Comments of Grid United at 4

PGE's response

PGE agrees that including more proxy transmission resources would be beneficial and will consider developing interregional transmission options as we determine next steps for improving our transmission modeling going forward.

Chapter 3. Additional energy efficiency

3.1 Action Plan

Staff, CUB, and Energy Advocates recommend the inclusion of the ~50 MWa of additional energy efficiency (EE) that reduced long term cost and risk as shown within portfolio analysis.[25,26,27] Staff also noted that based on PGE's response, they believe that the procurement risk of EE is smaller and more quantifiable than procurement risks of other resources in the Preferred Portfolio, pointing to ETO's historical record of and ongoing discussion with ETO, and noting the relative size of the risk across transmission, storage, and EE. Staff also asked PGE to provide an update on the ongoing collaboration with ETO to procure the additional EE by 2030.[28]

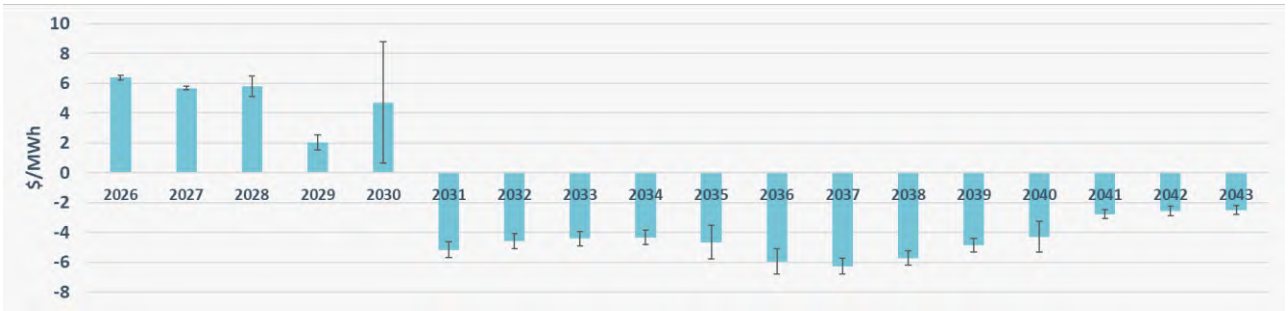
PGE's response

As shown in portfolio analysis, the additional ~50 MWa of EE above and beyond what is forecasted by ETO as cost-effective (based on previous avoided costs) compares favorably to other supply-side resource options that are transmission constrained. While PGE's proposed Action Plan includes the procurement of all cost-effective energy efficiency that is forecasted by ETO, PGE elected not to commit to the near-term rate increases that are associated with the additional increment of EE in the proposed Action Plan. This is because PGE believes that the level of new federal, state, and local resources being directed in support of energy efficiency is truly historic and dramatically changes the procurement options for energy efficiency. There may be less costly options emerging for our customers to access the additional energy efficiency than procuring it through rates. To further illustrate the rate pressure impact, PGE has compared the Preferred Portfolio developed as part of these Reply Comments with and without the additional EE.[29] Consistent with prior findings, when available the model selects a portion of the additional EE available ~50 MWa and it reduces

[25] LC 80 Round 1 Comments of Staff at 29
[26] LC 80 Round 1 Comments of CUB at 2
[27] LC 80 Round 1 Comments of Energy Advocates at pp. 5-7
[28] LC 80 Round 1 Comments of Staff at 29
[29] **Section 6.2.4** details the Preferred Portfolio developed as part of PGE's Round 1 Comment response.

the NPVRR of the portfolio by $532 million across the planning horizon.[30] This decrease in long-term cost should be compared against the increase in yearly rate pressure, which is displayed in **Figure 3**.

Figure 3. Price impact of the Preferred Portfolio with and without additonal EE[31]



Never-before-seen levels of new federal funding for energy efficiency, enabled through the IRA and IIJA, may fundamentally alter the market landscape for EE and demand response opportunities for our customers. At the same time, there are significant new local and state resources, including the Portland Clean Energy Fund (PCEF) and DEQ's Community Climate Investments fund (CCI), that will bring additional energy efficiency opportunities to customers in our service territory. On its own, PCEF plans to spend $150 million/year for the next five years just within the City of Portland, which is a greater investment than ETO spends annually on conservation within PGE's service territory.

The additional ~50 MWa increment of energy efficiency mentioned in our plan is not modeled to be added until 2026.[32] Between now and then PGE anticipates greater clarity on many uncertainties germane to the expansion of EE in our service territory through these other investments. Further, the ~50 MWa resource labeled as Energy Efficiency represents an opportunity to acquire related DER measures where co-deployment can save money in relation to independent procurement actions. This fact highlights a limitation of the current capacity expansion analysis yet opens an opportunity which should be thoroughly discussed with stakeholders and the Commission. Examples of measures which carry both EE and flexible load values include insulation, smart thermostats, water heating and space heating. PGE views this fact along with coordination of federal funding as an opportunity to procure both energy efficiency and more dynamic flexible load resources. Co-deployed measures which procure additional flexibility and dynamic capabilities grant PGE operational capabilities which solely procuring EE would not. Although co-deployment would increase the dollars necessary to acquire installation of the measure the coordinated approach would

[30] The exact quantity selected is (and has been) 53 MWa; PGE uses '~50 MWa' in this document as that value has been used in earlier comments and in public meetings.
[31] A positive (negative) value suggests a higher (lower) yearly cost per MWh of the portfolio with the additional EE
[32] An initial date of 2026 in the CEP/IRP represents a resource that is procured before December 31st, 2025

save customer dollars overall. In the recent past through our demand response programs such as Smart Thermostats and our U.S.DOE grant project within the Smart Grid Testbed known as the SALMON Project, ETO and PGE have learned that energy efficiency and flex load can be co-deployed. These facts and lessons learned regarding the co-benefits of co-deployment points to a pathway by which the expenditure to procure the 50 MWa identified in the IRP can provide a host of benefits to customers beyond EE, and when coordinated across funding streams and measure types each dollar used to acquire the greatest customer and system benefit.

To this end we request the Commission grant the opportunity to all DSM procurement entities to coordinate both how and what is procured through which entities. This should magnify the effects of this rare funding opportunity but also acquire the greatest benefit at the lowest overall cost than if each entity operated independently. We recognize that this process adjustment may affect the Energy Trust two-year budgeting process. Later this year the Energy Trust is charged with delivering a two-year budget to the Commission, its Board, and funding utilities. PGE requests that the Commission be flexible regarding the delivery of Energy Trust two-year budget to create time for all entities to come together to work collaboratively to develop a proposal to acquire the necessary energy efficiency and other benefits.

Over the next 12-24 months, the scale of new energy efficiency investments in our service territory from federal, state, and local sources combined will become more readily apparent, and that anticipated energy efficiency resource will be included in the next round of IRP modeling. In other words, some, if not all, of the additional 50 MWa of energy efficiency that portfolio modeling shows today to be beneficial to our customers post 2026 may come online in our service territory through mechanisms that are neither procured by PGE nor paid for in rates by our customers.

We are also observing promising technological advancements by data centers and the semi-conductor industry toward deeper energy efficiency. For all these reasons, we chose not to include the additional 50 MWa of additional energy efficiency in our proposed short term Action Plan as this issue can be revisited, with the benefit of clarity on these other funding mechanisms and technology evolution, in the next IRP. In the meantime, PGE is coordinating closely with ODOE, PCEF, DEQ, ETO, municipalities, and other entities to bring as many of these dollars to our service territory as we can to help alleviate rate pressure for our customers and grant our customers greater access to energy savings opportunities. Because of the way energy efficiency is currently funded in Oregon the cost of the additional 50 MWa would hit our customers as a significant increase in rates in the near term, before the customer benefits of energy savings accrue. This is on top of the rate pressure we already anticipate from resource acquisition to meet emissions targets by 2030. Moreover, as we discuss in comments below, PGE agrees with Staff, CUB, and other stakeholders that a discussion of alternative funding mechanisms to address the issue of near-term rate pressure

resulting from increasing spending on EE is needed. That discussion almost certainly takes place outside of LC 80 but will inform PGE's next IRP.

Affordability for our customers is our core priority as we transition to a cleaner energy system. Our decision to hold off on a commitment to additional energy efficiency acquisition through customer dollars until the totality of the additional funding sources and markets changes prompted by recent federal, state, and local policy are clarified should not be interpreted as weak support for energy efficiency as a resource important to decarbonization. PGE will continue to explore potential avenues to increase EE adoption through multiples channels while addressing near-term rate pressures.

3.2 Portfolio considerations

Energy Advocates asked for more details on why the long-term benefits highlighted within portfolio analysis are not sufficient basis for the inclusion of the additional EE. [33]

Staff noted that the OPUC has the tools to mitigate rate shocks to customers and advised PGE to work with the Commission to consider mechanisms to amortize or spread the cost of EE over multiple years. [34] CUB appreciated PGE's focus on near-term rate impact of EE but pushed back against considering utility rate base financing as a potential solution. However, CUB expressed an interest in discussing how securitization could be a solution to reduce the near-term rate burden. Specifically, CUB is interested in understanding if the amount is worth securitizing, the associated risks, its potential impact on PGE's credit rating and PGE's capital structure. [35]

Differing from CUB and Staff, the Energy Advocates argued that spreading costs over time through mechanisms such as financing or securitization impose higher costs on customers, due to the costs of financing. Specifically, they sought additional clarity on the policies that PGE believes must be amended to enable the inclusion of additional EE within PGE's Action Plan. [36]

PGE's response

IRP portfolio metrics of Cost, Variability, and Severity as well as community benefits and decarbonization were evaluated for each portfolio and displayed in the CEP data template. However, PGE also scrutinized portfolios that have different dimensions of cost and risk. For example, non-quantifiable procurement risks were used in the evaluation of the "Backloaded decline" decarbonization glidepath portfolio; despite showing lower Cost and Risk metrics,

[33] LC 80, Round 1 Comments of Energy Advocates at pp. 5-7
[34] LC 80, Round 1 Comments of Staff at 29
[35] LC 80 Round 1 Comments of CUB at 2
[36] LC 80 Round 1 Comments of Energy Advocates at pp. 5-7

PGE elected to not pursue this emission reduction glidepath because of the risk associated with procuring the required quantity of resources and the operational challenges of integrating them into the portfolio. Each of these risks are present in all portfolios to varying degrees but not quantitatively evaluated for all portfolios; nonetheless, they are both critical when determining the set of choices that make up the Preferred Portfolio. Similarly, when considering the additional energy efficiency portfolios PGE considered the unique implication of these resources on near term rates. While PGE did calculate and present the near-term cost impacts of all portfolios, the Company only presented this information for the EE portfolio as they were the only ones that were materially different across portfolios.

PGE is pleased to hear a willingness and ability of Staff to address the issue of near-term rate pressure resulting from increasing spending on EE. Addressing the comments by CUB, PGE believes this amount of spending on additional EE may be worth securitizing. PGE wouldn't want to securitize future costs if there is no guarantee that Energy Trust can perform the work, or if there are uncertainties in passing on the associated costs to customers. The process of securitization guarantees that we will bill the customer, guaranteeing debt payments over the life of the securitization. It would be credit negative if there was a potential for insufficient collection of payment in future years. Regarding the impact of securitization on the Company's capital structure and credit rates, PGE adds to the balance sheet with this debt, and adds cash on the asset side. In our disclosures we can note the capital structure with and without the securitized debt. If the financing order and state pledge, true up mechanism are strong, the rating agencies can view securitization as credit positive. Moreover, securitization doesn't address the emerging pathways now possible because of historic federal, state, and local resources for our customers to access energy efficiency, as discussed above. We believe that securitization, and other potential mechanisms for financing energy efficiency should be considered as part of a coordinated and integrated strategy to leveraging all of the now available resources to deliver energy efficiency to our service territory.

In response to the Energy Advocates highlighting customer savings from not amortizing EE, PGE notes that the costs savings associated with not financing or securitization EE are real but negatively impact near term affordability like other cases where loans are used to reduce the upfront expense. When comparing the near-term rate impact between the current Preferred Portfolio (revised below in **Section 6.2.4, Offshore wind in Preferred Portfolio**) and the same portfolio with access to EE, the portfolio with EE increases the yearly price by an annual average of 6 percent between 2024 and 2030.

3.3 Planning and execution

The Energy Advocates also noted a seemingly inconsistent approach to determining the quantity of EE that is cost-effective both through ETO's budget process and through the

CEP/IRP process. Additionally, the Energy Advocates noted the need for additional discussion on the topic of cost-effectiveness. [37]

PGE's response

Clarifying the nuance between EE targets set in the CEP/IRP and Energy Trust's budget setting process, PGE notes that the CEP/IRP provides directional insight based on proxy resource characteristics, which are used to set planning targets for EE, DR, and CBREs. For EE specifically, the proxy nature of the resource characteristics reflects planning assumptions made by both Energy Trust and PGE including estimated program costs and modeling approach.

Developing final program designs that maximize deployment of a specific measure/technology in the near-term, usually the following year or two, occurs during the ETO budgeting process. This is analogous to the DR procurement and the RFP process, where specific technologies and implementation details are decided downstream of the CEP/IRP process. Thus, while the CEP/IRP is the appropriate venue to determine the longer-term role of EE and its impact on system costs and risks, the ETO budget process is the appropriate venue to determine the final quantity of cost-effective, reliable, and feasible EE that will be procured for customers in the following year.

The difference between the targets set in the CEP/IRP and during the budget process, if any, would present as a risk of over or under procurement. Under procurement is commonly addressed by an increased reliance on existing thermal generation and market purchases, both of which can increase the risk that net variable power costs and/or PGE's emissions increase in that year.

The CEP/IRP targets and the ETO budget process are linked primarily through avoided costs, which are provided through regular yearly updates in UM 1893. A directional change in EE CEP/IRP will eventually be realized downstream through first updating avoided costs provided within UM 1893 and then ensuring the Energy Trust budget process has the appropriate resources to incorporate any change in direction. PGE notes that the CEP/IRP targets, while helpful, do not represent a necessary condition to changing EE procurement as long as both downstream process (updated avoided costs and the Energy Trust budget process) are completed.

Regarding the topic of cost-effectiveness, PGE notes that in the context of IRPs a resource is "cost-effective" if it is chosen within portfolio analysis (ROSE-E model), which optimizes for a least cost system. Thus, the ~50 MWa of additional EE evaluated in the CEP/IRP is "cost-effective" from a CEP/IRP perspective. Conversely, the remaining additional EE and the additional DR that were evaluated were not deemed cost-effective. This connotation of cost-

[37] LC 80, Round 1 Comments of Energy Advocates at pp. 5-7

effectiveness was also noted in comments by Staff.[38] Also note that the CEP/IRP notion of cost-effectiveness is independent of the method of procurement. IRP analysis aggregates ETO's forecasts to specific bundles based on levelized costs; while this approach is necessary for including many relatively small EE measures in IRP portfolio analysis, there are important differences between it and ETO's estimates of what it can procure at different price points.

However, outside the IRP, the term cost-effectiveness is referring to understanding if a resource is equal to or above 1 on a cost-effectiveness test. The cost-effectiveness test aims to mimic the dynamics within portfolio analysis with the added impact of certain non-energy benefits and the 10 percent cost reduction credit, as applicable. Cost-effectiveness tests attempt to mimic portfolio analysis by using avoided costs as their inputs, which are developed by studying the dynamics taking place within portfolio analysis. Discussing this connotation of cost-effectiveness within the IRP could be confusing because of the absence of a cost-effectiveness test and is not directly relevant because portfolio analysis determines which resource combination is optimal to ensure a reliable least cost system. To prevent conflation PGE elected to not use either connotation of the word in these discussions. PGE is open to discussing the use of these terms with stakeholders and address any confusion in their meaning.

3.4 Avoided costs within UM 1893

Staff noted concerns that the avoided costs provided by PGE using the established UM 1893 workbook do not adequately capture the value of EE as demonstrated within portfolio analysis.[39]

PGE's response

Avoided costs are developed by studying portfolio analysis and are inputs for cost-effectiveness tests among other applications. Avoided costs provided for EE follow established methods of estimating energy and capacity values as set by UM 1893. These methods have not evolved with the evolving landscape of the CEP/IRP. There are two dynamics that are not captured within the currently established methods of UM 1893:

- The UM 1893 method uses a single value for capacity usually based on the cost of capacity in the first year of deficiency, 2026 in this CEP/IRP. This approach does not capture two dynamics that have become more prominent in this IRP: the decreasing capacity contribution of the marginal resource that can provide capacity over the planning horizon, which impact the cost of capacity, and more importantly, the impact of transmission and other constraints that limit the type of resource available to meet

[38] LC 80 Round 1 Comments of Staff at 27
[39] LC 80 Round 1 Comments of Staff at 28

capacity needs, which do not bind/limit resource selection until after the 2-3 years of the analysis.

- Similarly, the UM1893 method to value energy is based on using electricity prices. The decrease in the electricity price forecast over the planning horizon in the Reference case is rightly identified by Staff as the reasoning for decreasing energy value. However, this approach might not be appropriate within portfolio analysis because the model has limited access to market purchases which are priced at the electricity prices. Any additional energy needed to meet energy needs while complying with HB 2021 must be addressed through new resource additions, whose net cost may be higher or lower than electricity prices. The net cost of these new resources would increase when accounting for transmission constraints. This dynamic, while captured endogenously within portfolio analysis, is not captured in the current UM 1893 methods and is the likely driver of the selection of EE within portfolio analysis. PGE also noted this in the last roundtable meeting prior to filing.[40]

Thus, as PGE noted in the filed CEP/IRP, established methods especially related to energy value estimation might not capture the value of EE when considering emissions and transmission constraints. This gap between electricity price and net cost of the marginal energy resource was labeled as the cost of clean energy. PGE reiterates the need to undertake additional study to determine how both HB 2021 and transmission availability impact avoided costs, especially energy related avoided costs for resources that can avoid further transmission buildout. PGE is currently undertaking an effort to understand how UM1893 avoided costs must evolve to replicate the results of portfolio analysis but has not made sufficient progress to provide an update at this time.

[40] March 30th roundtable available at: https://assets.ctfassets.net/416ywc1laqmd/74fBbECgfODO17Gkgffl3z/9a726ecb1032d9d5b6310588f35379b4/IRP_Roundtable_March_30_23-3.pdf

Chapter 4. Methods

4.1 Price forecasting

On the topic of price forecasting, AWEC states that PGE's market price forecast is not reliable; therefore, energy values and the portfolios and portfolio costs generated by ROSE-E are unreliable.[41] AWEC states that PGE's long-term market price forecast is not consistent with planned resource additions or planned sales of emitting energy.[42] Additionally, AWEC notes that PGE's PZM model does not consider transmission constraints leading to an inability to simulate dispatch needs and properly model variable energy resource (VER) curtailments.[43]

PGE's response

In this CEP/IRP and previous IRPs energy value has been useful to differentiate between potential incremental generation resources with the annual granularity of IRP portfolio modeling.[44] PGE agrees that this current CEP/IRP energy value construct is imperfect and appreciates AWEC highlighting this issue. The Company further agrees that there are assumptions used in previous IRPs regarding energy value that have the potential to break down with higher renewable penetration. Currently, the energy value used in the IRP analysis is created against a counterfactual of unspecified market purchases that might not be appropriate given the emission reduction targets associated with HB 2021.

PGE has previously recognized the granularity of energy accounting in portfolio analysis as an area of future improvement in order to better match the timing of energy generation with energy needs.[45] Moving from annual to monthly accounting of energy needs in portfolio analysis could help to differentiate between energy resources without relying on energy value by allowing for intra-annual variation in the timing of energy needs and renewable generation patterns to be accounted for in resource selection.

However, these areas of potential future improvement do not invalidate PGE's portfolio analysis results. Currently, resource additions in portfolio analysis are driven by needs and key constraints like transmission availability and emissions targets, not power prices. Conversely, in the 2019 IRP a main question of interest was the estimation of energy value, as

[41] LC 80 Round 1 Comments by AWEC at pp. 2
[42] LC 80 Round 1 Comments by AWEC at pp. 4-6
[43] LC 80 Round 1 Comments by AWEC at pp. 6-7
[44] Energy value ($/MWh) in the IRP has typically been estimated by summing the forecasted generation multiplied by the expected price for each hour.
[45] See meeting materials from PGE's March 30, 2023 roundtable meeting at https://assets.ctfassets.net/416ywc1laqmd/74fBbECgfODO17Gkgffl3z/9a726ecb1032d9d5b6310588f35379b4/IRP_Roundtable_March_30_23-3.pdf

the main driving factor for resource additions was their associated energy values. However, the use of energy value to distinguish between specific resources is not the driving force of current portfolio outcomes, and effectively the same quantity of incremental resource additions would be required even if the energy value of each were removed from the analysis. Portfolio costs produced in the IRP are used to compare portfolios against one another and because all portfolios rely on the same source of energy values, any shortcomings in the forecast of power prices that is applied consistently across all portfolios do not invalidate the insights gained from portfolio analysis. Additionally, the modification of power costs within PGE's General Rate Case does not necessarily invalidate the energy value forecast as AWEC implies in their comments. There are additional factors, such adverse energy market conditions, that can affect power costs and should be considered before assuming the energy value forecast is incorrect.

4.2 ELCC values

4.2.1 Reported ELCC values

Staff noted that the ELCC value of Gorge Wind in the 2023 CEP/IRP is "much larger than in the 2019 IRP Update."[46] They ask why this occurred. Staff also asked why there are differences between the tuned and untuned ELCCs calculated in the CEP/IRP.[47]

PGE's response

Resource ELCC values depend on the characteristics of the resource being evaluated as well as the base system in which they are tested. Both the Gorge Wind generation profile from the 2019 IRP Update and the relevant base system are different in the 2023 CEP/IRP. For these Reply Comments PGE tested the ELCC of the 2019 Gorge Wind shape in the 2023 CEP/IRP model and found that it has a lower value than the 2023 CEP/IRP resource, signifying that the new shape plays a role in the increased value compared to the 2019 IRP Update.[48] The shape in the 2023 CEP/IRP is based on publicly available NREL data and is further discussed in Appendix M. Supply-side options of the filed CEP/IRP.[49] The 2019 IRP Update shape was created by HDR, a consultancy, and is the same shape used in the 2019 IRP.[50]

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[46] LC 80 Round One Comments of Staff at 44
[47] LC 80 Round One Comments of Staff at 44
[48] The 2019 IRP Update Gorge Wind shape in the 2023 CEP/IRP model had a summer/winter ELCC value of 42%/32%, respectively. For comparison, the annual ELCC value in the 2019 IRP Update for Gorge Wind was 25%, and the 2023 CEP/IRP Gorge Wind shape in the 2023 CEP/IRP is summer/winter 47%/39%, respectively.
[49]https://downloads.ctfassets.net/416ywc1laqmd/6B6HLox3jBzYLXOBgskor5/63f5c6a615c6f2bc9e5df78ca27472bd/PGE_2023_CEP-IRP_REVISED_2023-06-30.pdf
[50] See Chapter 6 of the 2019 IRP for more information: https://portlandgeneral.com/about/who-we-are/resource-planning/combined-cep-and-irp/combined-cep-irp-resources-materials

When tested in the 2023 CEP/IRP model, the 2019 IRP Update Gorge Wind shape has a higher ELCC than in the 2019 IRP Update, indicating that the base system also plays a role in the different ELCC value. One potentially synergistic change to the base system between the 2019 IRP Update and the 2023 CEP/IRP is the inclusion of 400 MW of 4-hour RFP proxy batteries.[51] The change in resource ELCC value between two different base systems is often referred to as the "portfolio effect", where the resource portfolio (or base system) can alter resource ELCC values. This was partly discussed in the August 2022 Roundtable as well as in Appendix J of the CEP/IRP (with a focus on storage resources).[52]

Another portfolio effect item is resource saturation, which can lead to lower ELCC resource values. For example, a base system with high levels of solar resource may see reduced outages during daylight hours since existing solar is generating in those hours. This reduces the ELCC value of incremental solar resources since they have fewer outages available to solve. Tuned ELCCs are tested in a different system than untuned ELCCs and include the Preferred Portfolio resources. As a result, they have a different base system than the untuned ELCCs (and a different base system for each tuned year tested). This leads to different ELCC values between the tuned and untuned approaches. For the untuned ELCCs the CEP/IRP currently only includes same resource saturation (for example the quantity of Wasco Solar added reduces the next increment of Wasco Solar's ELCC), however, it does not incorporate similar resource saturations (for example, an addition of Christmas Valley Solar does not currently reduce the next increment of Wasco Solar's ELCC). More work is needed to better incorporate the portfolio effect into future planning cycles.

4.2.2 ELCC calculation methodology

RNW provided a number or ELCC methodology comments and suggests that PGE incorporate them in the next planning cycle.[53] Specifically, they ask PGE to take the portfolio effect into account when calculating ELCC values, to calculate ELCC values in multiple years, to include an ELCC validation process, and to think of ELCCs as more of a surface than a curve.[54] AWEC comments that the ELCC values in the CEP/IRP do not consider the impact of similar resources being added to the portfolio.[55] They think this may overstate resource ELCC values and lead to a capacity deficit Preferred Portfolio.

[51] Updated to 475 MW in the Addendum to reflect committed procurement quantities.
[52] PGE August 2022 Roundtable at minute 47 to 133
[53] LC 80 Round One Comments of RNW at 14-16
[54] LC 80 Round One Comments of RNW at 14-16
[55] LC 80 Round One Comments of AWEC at 8-9

PGE's response

PGE agrees that the portfolio effect can have a tangible impact on estimates of resource ELCC. It was partly discussed in the August 2022 Roundtable as well as in Appendix J of the CEP/IRP (with a focus on storage resources).[56] For example, a battery ELCC may change (often improve) if tested in an energy adequate rather than deficit system since it can charge more reliably. Another aspect of the portfolio effect is resource saturation. For example, a wind resource ELCC may decline if tested in a system that already includes wind resources that follow a similar generation pattern.[57] The multiyear ELCC recommendation suggested by RNW is like the portfolio effect, assuming Preferred Portfolio resources are added to the system when ELCCs are tested. AWECs comments are related to the portfolio effect as well, specifically resource saturation due to the addition of similar resource types.

PGE will consider expanded analysis of the portfolio effect in future CEP/IRPs, potentially by running iterative ELCCs in key years. For example, ELCCs could be run for the first year of significant deficit and run again in a later year while incorporating Preferred Portfolio resources. However, expanded analysis of the portfolio effect will increase workload and may result in compromises like fewer resources being tested and/or fewer resource levels being tested.

In the 2023 CEP/IRP PGE tests ELCC values using a 'ladder' approach. Larger and larger nameplate MW amounts of the same resource are added to the portfolio to provide an estimation of how the ELCC value changes due to resource saturation (typically they decline). PGE agrees that ELCC values should ideally be treated like a surface rather than a curve, with multiple resources of different technologies being added to the portfolio simultaneously. However, analyzing an extra dimension of ELCC analysis increases workload and may not be feasible. For example, the Northwest Power & Conservation Council calculated the ASCC (similar to ELCC) for seven resource types at two levels of capacity and found that to "fill the ASCC array with every combination of resource type and capacity addition requires 128 studies."[58] PGE tested ELCC values of over 20 resources (including transmission variations) for the CEP/IRP. If an ELCC array was constructed at two addition levels and with 20 resources, there would be over 1 million resource combinations. PGE is currently evaluating the trade-offs presented between precision and increased modeling time.

One potential approach to validating ELCC values is back-checking the Preferred Portfolio. This involves taking the Preferred Portfolio resources, which are selected by the portfolio analysis model, and running them through the adequacy model to test the system adequacy level. This helps determine if the resources selected are providing the estimated amount of capacity based on their ELCC values, or if the portfolio effect is skewing the ELCC values

[56] PGE August 2022 Roundtable at minute 47 to 133
[57] Most variable energy resources see decreasing ELCC values as more of the same resource is added to the portfolio.
[58] This is equal to 2^7: https://www.nwcouncil.org/2021powerplan_associated-system-capacity-contribution/

(which would result in an overly surplus or deficit system). A multiyear back-check was performed as part of these comments and can be found in **Section 4.3.1, Resource adequacy metrics in the CEP/IRP**, with loss-of-load-hours and loss-of-load-events reported out for select CEP/IRP years. PGE directs AWEC to this section as well regarding their system adequacy concerns. PGE is open to exploring other ELCC valuation methods in the next CEP/IRP.

4.3 Resource adequacy

4.3.1 Resource adequacy metrics in the CEP/IRP

Staff notes that PGE's adequacy standard, 2.4 loss-of-load hours (LOLH) per season, results in a 4.8 annual LOLH standard. They also ask for PGE to calculate the LOLH and loss-of-load-expectation (LOLE) of each year in the CEP/IRP while including the Preferred Portfolio in the adequacy model, and ask why PGE chose to plan for that level of reliability.[59] AWEC raises concerns that PGEs Preferred Portfolio may be capacity deficient due to the estimation method used for resource ELCCs and due to the Preferred Portfolio not being tested in an hourly adequacy model.[60]

PGE's response

In the CEP/IRP modeling workflow, the LOLH standard is passed from the adequacy model to the portfolio model as the amount of effective capacity, by season, that needs to be acquired to maintain adequacy. The 2.4 LOLH is an interpretation of the 1-day-in-ten year standard and was used in the 2019 IRP and 2019 IRP Update. The standard is applied seasonally in the 2023 CEP/IRP to ensure a seasonally balanced system.[61]

Applying a 2.4 LOLH per season does not result in 4.8 LOLH annually in the CEP/IRP. For example, for year 2026, the summer capacity need in the Addendum is 718 MW, the winter need is 522 MW, and the annual need (which is not published in the CEP/IRP) is 622 MW. As a result of acquiring enough capacity to meet summer and winter need, annual need is met as well. This is further demonstrated in **Table 3** which shows annual adequacy metrics for the Preferred Portfolio in the 2023 CEP/IRP.

At different stages of portfolio analysis PGE checked the adequacy of year 2030 for the filed CEP/IRP and year 2028 of the Addendum.[62] **Table 3** provides annual LOLH and LOLE metrics for select years out of the filed IRP. Most of these years were tested to address these

[59] LC 80 Round One Comments of Staff at 43
[60] LC 80 Round One Comments of AWEC at 7-8
[61] As opposed to a system that is overly adequate in one season, deficient in another, but balanced on the year.
[62] 2028 was tested in the Addendum to align to the Action Plan capacity target and to avoid modeling generic variable energy resource which begins to appear in the Addendum in 2030.

Comments (as was the calculation of the LOLE metric).[63] The values are estimated by adding the Preferred Portfolio resources to the adequacy model. The LOLE values are provided for informational purposes only (LOLE is not used in the CEP/IRP).

Table 3. Preferred Portfolio LOLH and LOLE values, filed CEP/IRP

Year	LOLH	LOLE
2026	1.913	0.244
2027	1.091	0.161
2028	1.577	0.213
2029	1.459	0.307
2030	2.497	0.565
2036	0.145	0.063
2043	1.378	0.292

Looking at the values from the filed CEP/IRP, the resource adequacy levels stay between 1.091 and 2.499 LOLH from 2026 through 2030, and in year 2043. Due to the portfolio effect (resource interactions inside the portfolio) and the portfolio model having a static view of ELCC values, there will likely always be some difference between the LOLH target and the LOLH value after back-testing.[64] Year 2036 is capacity surplus. This surplus is partly due to the portfolio model building surplus capacity resources in preparation for the 2040 capacity need increase and may also be due to the portfolio effect as thousands of MW of new resources are added to the system by 2036.[65] As this analysis conducted by PGE to address Staff's concerns shows, LOLH values from the filed CEP/IRP are consistent with the 2.4 LOLH standard throughout the planning horizon.

LOLE values are numerically lower than LOLH values. This is due to the LOLE calculation which indicates number of adequacy events (which may be multiple hours in length) divided by number of years simulated, versus LOLH which indicates number of hours (which could occur in the same event) divided by the number of years simulated. As a result, the numerator in the metric calculation, and thus the final metric value, is nearly always larger with LOLH (hours) versus LOLE (events).[66]

Table 4 provides LOLH and LOLE values for the Addendum Preferred Portfolio. In the Addendum, the model indicates LOLH values between 1.531 and 1.994 from 2026 through

[63] LOLE is interpreted as the number of days with an outage divided by total years simulated. A consecutive two-day outage is interpreted as two different events, two separate outages in the same day are interpreted as one event.
[64] For example, in the 7th Power Plan, which targeted a 5% LOLP adequacy metric, the Northwest Power & Conservation Council targeted back-checked portfolio results between 2% to 5%. Please see page 11-4: https://www.nwcouncil.org/sites/default/files/7thplanfinal_allchapters_1.pdf
[65] The need for capacity rises sharply in 2040 when emitting resources can no longer be used for retail load service.
[66] PGE uses 2.4 LOLH as an interpretation of a one-day-in-ten outage standard, allowing up to 24 hours of outage per ten years in the model. Some organizations use 0.1 LOLE as a one-event-in-ten standard, allowing one event per ten years. Since most adequacy events are shorter than 24 hours the 0.1 LOLE standard is typically stricter than a 2.4 LOLH standard.

2028. Years 2029 and 2030 are capacity surplus. This is due to the portfolio model needing more clean energy to meet HB 2021 targets, having limited resources available to select, and the assumed characteristics of those resources. For example, 553 MW of Wyoming wind and Desert SW solar resource are added in 2029, among other resources. With their associated transmission they provide 553 MW of effective capacity. However, the capacity need increase from 2028 to 2029 is 116 MW in the winter and 211 MW in the summer (164 MW average). As a result, to meet energy needs, the system is capacity surplus in those years. The Addendum portfolio is also capacity surplus in 2036 and in 2043. This is likely due to a multitude of factors including the portfolio effect and the max build constraint that smooths capacity additions ahead of the 2040 zero emissions requirement as discussed above. Like the filed CEP/IRP, the 2.4 LOLH target is met in all years, with some years capacity surplus due to the need to acquire high capacity resources to meet energy needs in portfolio analysis, as well as the portfolio effect and other factors in later years.

Table 4. Preferred Portfolio LOLH and LOLE values, CEP/IRP Addendum

Year	LOLH	LOLE
2026	1.994	0.260
2027	1.945	0.264
2028	1.531	0.191
2029	0.051	0.014
2030	0.051	0.020
2036	0.313	0.068
2043	0.385	0.020

4.3.2 Resource adequacy methods in future CEP/IRPs

RNW provided several comments on PGE's resource adequacy needs assessment to be taken into consideration for the next planning cycle.[67] Specifically, RNW asks that PGE incorporate a suite of adequacy metrics into its adequacy modeling, that PGE should not align the adequacy models outage distribution curve from greatest to smallest, for PGE to investigate tail adequacy risks, for PGE to incorporate economic considerations in the adequacy model to assess the cost/benefit of different adequacy levels/resource additions, and to incorporate the ability to buy market power during daylight hours due to increased levels of solar power in the West.[68]

[67] LC 80 Round One Comments of RNW at 9-13
[68] LC 80 Round One Comments of RNW at 9-13

PGE's response

PGE disagrees that a suite of planning metrics is necessary for a resource adequacy study. Many adequacy studies, including the WRAP, are based upon single metric criteria.[69] That said, PGE provides a view of another adequacy metric, loss-of-load-events (LOLE) as part of this comment response in **Section 4.3.1, Resource adequacy metrics in the CEP/IRP**. Additionally, PGE plans to engage in discussions with the Northwest Power & Conservation Council, and other stakeholders who want to contribute, regarding the benefits of a multi-metric approach, and will consider whether such a change would be an improvement to PGE's current approach.

PGE disagrees with the comment that outages should not be aligned from largest to smallest when calculating LOLH. The largest to smallest alignment method used by PGE for capacity determination in adequacy models is used by other organizations, including the Power Council in the 7th Power Plan, and provides increased efficiency over an iterative approach.[70] PGE also disagrees that the adequacy model should incorporate economics to value adequacy since PGE does not use a value-of-lost-load metric.[71] Finally, tail risk analysis is interesting from a qualitative perspective, but difficult to draw actionable results from. That said, the Company is open to working with stakeholders to explore tail risk analysis in the next planning cycle, in part to see if the types of adequacy events in the model are changing over time.

PGE agrees that a more granular power market should be incorporated into the adequacy model. This is also noted on page 14 of the CEP/IRP Addendum. This could be a solar market as suggested by RNW, a more granular look at hourly market power availability, a combination of the two, or another approach.

4.3.2.1 WRAP and CEP/IRP adequacy

Staff asks that PGE in future CEP/IRPs take the WRAP into consideration including making adjustments to system reliability need, capturing savings opportunities related to WRAP, and capturing other program benefits.[72] RNW asks PGE to incorporate WRAP related items into the CEP/IRP while noting that adequacy in the CEP/IRP and the WRAP will remain parallel

[69] The WRAP plans to use a 1-in-10 LOLE metric, please see page 57: https://www.westernpowerpool.org/private-media/documents/2023-03-10_WRAP_Draft_Design_Document_FINAL.pdf
[70] Please see page 11-19 ad Figure 11-7: https://www.nwcouncil.org/sites/default/files/7thplanfinal_chap11_systemneedsassess_1.pdf
[71] Economics in an adequacy model is also useful for energy-limited resource dispatch logic, particularly if the model is using a longer duration (e.g., annual) timestep. For example, a model may consider the opportunity cost of using hydropower in January for economics even though it could still encounter an adequacy event later in the year. Given PGE's adequacy model run time (currently 1 week, or 168 hours) this consideration is less important for the PGE model today.
[72] LC 80 Round One Comments of Staff at 43-44

processes for the foreseeable future.[73] They recommend discussion and analysis of WRAP compliance in the CEP/IRP, using WRAP outputs to inform the CEP/IRP adequacy analysis on items like power market availability and the risk of transmission curtailment, and to improve CEP/IRP wrap alignment and integration via discussions with WRAP participants, the PUC, and other stakeholders.

PGE's response

As noted in the CEP/IRP, PGE plans to work "with WRAP participants and state regulators to ensure that state-level IRPs complement and work in harmony with regional resource adequacy programs."[74] PGE continues to engage with the WRAP effort and stakeholders, and continues to seek avenues to inform future CEP/IRP work via the WRAP, including capturing potential WRAP benefits. As noted in the CEP/IRP "There may be a future opportunity to link IRP power market availability assumptions to work done by the…" WRAP.[75] PGE may explore other WRAP related outputs and insights, including transmission curtailment risk, and how they can be built into future CEP/IRPs.

PGE is still assessing potential jurisdictional and methodological concerns between the WRAP, developing state-level RA frameworks, and CEP/IRP resource adequacy. For example, if the CEP/IRP finds the system to be adequate but the WRAP identifies an adequacy concern it is unclear what the correct course of resource action would be. For example, if estimates from the WRAP were higher than PGE's evaluated adequacy need estimates, would this be sufficient justification for an incremental resource addition? Or if PGE indicated a resource need and the WRAP indicated sufficiency, would PGE be expected to acquire additional resources? Some of these questions may be discussed in upcoming stakeholder meetings, WRAP meetings, OPUC dockets, or other forums.

Additionally, there are questions regarding if the WRAP planning margin can be used for long-term planning in the CEP/IRP, and if WRAP models/methodologies can be leveraged to produce ELCC values for CEP/IRP proxy resources. For example, for CEP/IRP adequacy, can the planning margin generated by the WRAP be extended outwards for comparison to the CEP/IRP or for resource action guidance? Specific to resource valuation, should efforts be made to align incremental resource ELCC values between the WRAP and the CEP/IRP to avoid potential seams issues?[76] PGE looks forward to continued dialogue with the WRAP and other stakeholders to help discuss and address these items, among other concerns.

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[73] LC 80 Round One Comments of RNW at 47-50
[74] LC 80 filed PGE 2023 CEP/IRP, at 66
[75] LC 80 filed PGE 2023 CEP/IRP at 511
[76] For example, the CEP/IRP could assess the ELCC of a resource at 40% whereas the WRAP models value it at 20%. This could lead to PGE identifying resources that are sufficient from an internal modeling perspective but insufficient (or overly surplus) from a WRAP perspective.

4.4 Operations

4.4.1 Adapting to the changing power system

The Energy Advocates discuss PGE's response to an Initial Comment response regarding the use of generic plant data in mid- and long-term models and actual data used in operational models.[77] They note that as more variable energy resources, demand response, and energy efficiency enter the system "operational strategies will need to evolve."[78] They specify that their Initial Comment was focused on how PGE plans to adapt to the changing power system. AWEC also notes that PGE should consider how to manage "energy shaping needs" given the decreasing amount of dispatchable resource energy that PGE can retain for retail load service.[79]

PGE's response

PGE agrees with the Energy Advocates and is actively evaluating the possibilities of a more granular modeling process for the next CEP/IRP, in part due to the projected increases of VER and demand side resources. We recognize the challenge of planning for a power system that will be different than the system today, and look forward to working with regulators, stakeholders, and other interested parties as we improve our CEP/IRP modeling approach. PGE discussed some of these modeling improvements at the March 2023 Roundtable meeting.[80] PGE notes these modeling improvements are long-term planning focused, and that the CEP/IRP provides a long-term plan for PGE, not an operations focused plan. Operations will also adjust in real-time based on actual conditions like weather, supply/demand dynamics, economic considerations, and more. As discussed in PGE's reply to Initial Comments, operations will continue to change to meet GHG reduction targets and adequacy requirements.[81]

4.4.2 Economic dispatch

Energy Advocates notes that the intermediary GHG model determines economic dispatch for retail load service before CO_2e targets are considered, and then assumes the excess generation after the target is met is sold out of state.[82] They ask for PGE to provide the details

[77] LC 80 Round One Comments of Energy Advocates at 10
[78] LC 80 Round One Comments of Energy Advocates at 10
[79] LC 80 Round One Comments of AWEC at 8
[80] Please see the IRP Limitations and Areas for Improvement section starting on slide 40: https://assets.ctfassets.net/416ywc1laqmd/74fBbECgfODO17Gkgffl3z/9a726ecb1032d9d5b6310588f35379b4/IRP_Roundtable_March_30_23-3.pdf#page=40
[81] LC 80 Round 0 Comments: PGE Response at 40-41
[82] LC 80 Round One Comments of Energy Advocates at 11-12

of the economic dispatch calculation and stated that this calculation should consider health impacts of thermal power plants and the social cost of carbon.[83] Both the Energy Advocates and NewSun suggest that thermal generation above that used for retail load should be reduced.[84]

PGE's response

Economic dispatch of thermal resources is estimated in the PZM model and is then passed to the intermediary GHG model. This process involves the following steps:

- Running the WECC-wide model to establish power prices in 39 different Price Futures
- Running the PZM model on economic dispatch in conjunction with those power prices to establish thermal plant dispatch for each Price Future[85]
- Using the intermediary GHG model to adjust thermal generation (estimated in the PZM) based on historical ratios of what is kept for retail load service versus sold on the market. It then adjusts generation for retail load service to meet GHG targets (usually a downward adjustment) and assumes the energy difference between economic dispatch and retail load service is sold on wholesale markets.

An EPA-derived social cost of carbon is included in some of the 39 Price Futures, although it is not included in the reference case Price Future. Carbon pricing is excluded since it does not exist in Oregon today, since HB 2021 reduces the possibility of future utility sector carbon pricing in Oregon (HB 2021 already targets utility emissions), and because the CEP/IRP focuses on minimizing costs under current and expected policies. These Price Futures feed into portfolio analysis. As a result, and due to our need to reduce emissions via HB 2021, PGE finds the current analytical process to be robust and does not believe the additional evaluation of the social cost of carbon or other externalities would lead to a tangibly different plan.

PGE disagrees with both the Energy Advocates and NewSun that thermal generation above that used for retail load should necessarily be reduced, as that is not a requirement of HB 2021. PGE continues to believe that economics will continue to drive thermal modeling even in the presence of Oregon's HB 2021 and all other applicable carbon regulation in Oregon or other states. Demand for thermal generation in other states will drive economic dispatch, but that demand is increasingly subject to carbon and clean energy policies in states. Additionally, in determining the structure of its thermal modeling PGE relied on guidance

[83] LC 80 Round One Comments of Energy Advocates at 11-12
[84] LC 80 Round One Comments of Energy Advocates at 11 and NewSun at 11.
[85] As discussed in Appendix H.1.2 Aurora PGE Zone Model, "Aurora simulates PGE existing dispatchable generation resources, contracts, and new resources using economic dispatch based on electricity prices and associated risk variable inputs consistent with each Price Future. When economically dispatched, resources will generate when resource dispatch cost is lower than the electricity market price and will not generate when market purchases are cheaper."

from Staff who suggested that economic dispatch should determine the total output of the Company's existing thermal fleet. As mentioned below, the improvement of its modeling of thermal resources will continue to be a priority for the Company in the face of market and policy developments, and PGE will also continue working with Staff and stakeholders to help determine the answers to these modeling questions.

4.5 Emissions accounting

4.5.1 Sub-annual emissions modeling

RNW comments that the CEP/IRP should include "Sub-Annual" accounting and analysis of emissions and include an operations-based view of emissions.[86] They note that sub-annual accounting is important due to the seasonality of load and generation profiles.[87] They also state that PGE should improve its analysis on curtailment and overgeneration risks.[88] They state that PGE's plan to sell excess generation into the market may be problematic due to generation correlations among Western resources, and without the ability to net clean energy against thermals that PGEs emissions strategy may be at risk.[89] Finally, they find that the current annual PGE modeling approach does not allow for identification of increased integration needs for variable energy resources.[90]

PGE's response

PGE agrees that annual energy/GHG modeling in the CEP/IRP does not account for seasonal variations of VERs and load. This limitation is noted in the March 2023 Roundtable meeting and we are committed to evaluating possible improvements to this approach.[91] CEP/IRP modeling portfolio modeling is currently done on an annual basis. It is not intended to be an energy or emissions netting strategy per se, and was developed to meet the annual evaluation used in portfolio analysis. At the March 2023 Roundtable we also identified VER integration as an area to evaluate for future modeling enhancements. This could include an investigation into sub-hour flexibility modeling.

PGE agrees that more granular modeling can provide insights into its clean energy position and overgeneration risks. Please see **Section 4.7.1, Hourly analysis of the Preferred**

[86] LC 80 Round One Comments of RNW at 20-23
[87] LC 80 Round One Comments of RNW at 20-23
[88] LC 80 Round One Comments of RNW at 20-23
[89] LC 80 Round One Comments of RNW at 20-23
[90] LC 80 Round One Comments of RNW at 20-23
[91] Please see the IRP Limitations and Areas for Improvement section starting on slide 40 of the March 2023 Roundtable: https://assets.ctfassets.net/416ywc1laqmd/74fBbECgfODO17Gkgffl3z/9a726ecb1032d9d5b6310588f35379b4/IRP_Roundtable_March_30_23-3.pdf#page=40

Portfolio for a newly conducted hourly Aurora PZM emissions analysis using the Preferred Portfolio.

4.5.2 Resource emissions shuffling

RNW raises concerns regarding resource 'shuffling.'[92] For example, they state that under the current modeling framework PGE could sell Colstrip into the power market while simultaneously buying unspecified market power at a lower emissions intensity rate, thus exchanging its higher emissions in favor of lower emissions. This would allow PGE to retain more GHG-emitting energy in the Preferred Portfolio. RNW states that this is shown in Table 4 of the Addendum since Beaver's annual generation retained for retail load service falls by 34 MWa while market purchases increase by 39 MWa as compared to the filed CEP/IRP in year 2024. RNW also provided broader comments regarding how emissions are assigned to PGE resources, and asks if there are implications for the Commissions determination of if the CEP/IRP is in the public's interest.

PGE's response

The intermediate GHG model does not consider resource 'shuffling' strategies. Rather, it effectively performs two tasks that are guided by economic dispatch and historical data:

1. It adjusts, for emitting resources, simulated economic dispatch (for PGE resources) or historical dispatch (for non-PGE resources) by historical ratios to account for retail load service vs. wholesale sales.
2. After adjusting for energy retained for retail load service the intermediate GHG model then adjusts emitting resource dispatch (usually downward) to ensure the GHG targets are met.

PGE disagrees with RNW comment about employing a resource 'shuffling' strategy in the CEP/IRP. If RNW's assertion was accurate PGE's modeling would show the retention of the lowest emission rate resources for retail load service and sale of the most emission intensive resources to the market. This would allow PGE to maximize the amount of emitting generation kept for retail load service. Instead, PGE's modeling uses historical data to guide how resources are retained for retail load service versus sold on the wholesale market. PGE finds this approach the most appropriate, as it relies on historical values that provide a non-biased calculation of how much power is typically retained for retail load versus sold on the market.

PGE also disagrees with RNW's statements about the modeled operation of Beaver. As explained in the July 7th Addendum, heat rate errors associated with thermal resources in the

[92] LC 80 Round One Comments of RNW at 23-25

filed CEP/IRP were corrected for the Addendum. This led to Beaver generating less energy in the CEP/IRP based on corrected economic dispatch. In the early years, like 2024, the GHG model often cannot move generation from one PGE resource (like Beaver) to another. This is due to PGE resources already being at their maximum retail load service levels allowed (which is set by Aurora PZM and the historical load service vs sales ratios). This is why the decreased Beaver generation in 2024 is mostly offset by market unspecified in 2024.

Regarding assignment of emissions to resources, for HB 2021 compliance the CEP/IRP targets emissions associated with retail load service. We also track and report total emissions (including those associated with wholesale sales) in the CEP/IRP and in the accompanying CEP Data Template.

4.5.3 Market unspecified emissions rate

RNW states that PGE suggests in the CEP/IRP that the market unspecified emissions rate should be reconsidered due to the increasing number of clean energy resources in the West.[93] They postulate that the demand for clean energy resources will grow due to climate policies, and the increased demand will lead to more clean resources being "claimed" or specified as emissions free, resulting in a higher future emissions rate for market unspecified resources.

PGE's response

PGE strongly disagrees with the claim that the CEP/IRP asks for a reconsidered market unspecified emissions rate and finds that statement as a mischaracterization of the CEP/IRP. The CEP/IRP does ask for improved specified resource tracking across the West, which could lead to some purchases that are currently unspecified becoming specified. Improved resource tracking will likely be necessary as utilities in the West decarbonize. In their comments, RNW notes that is already starting to occur, as "previously unspecified hydroelectric facilities are being newly specified in the portfolios of utilities…"[94]

Specific to the filed CEP/IRP page numbers highlighted by RNW:

- On page 16 we note that "PGE is committed to working with regional organizations to improve emissions tracking and accounting across Western markets to provide better visibility into the GHG content of market power" while also discussing that there are likely non-emitting resources as part of unspecified purchases. This CEP/IRP section is about improving resource tracking so we can identify and correctly account for clean power purchases.

[93] LC 80 Round One Comments of RNW at 25-27
[94] LC 80 Round One Comments of RNW at 26

- On page 95 we note that using market unspecified rates "may result in certain MWh receiving a higher CO_2e intensity compared to the actual CO_2e intensity of unspecified market purchases." In an Initial Comment response PGE clarified that some purchases may be above the rate as well.[95]
- On page 122 we clarify in a footnote that Figure 42 shows energy need "Assuming no change in the emissions rate used to account for GHG emissions associated with market purchases from unspecified sources." PGE does not find this sentence to be suggestive of a need to reconsider the market unspecified rate.
- The sensitivity on page 137 shows the impact on energy needs if half of unspecified purchases were reclassified as specified GHG free. This is a switch from unspecified to specified, not a claim that the market rate should be reconsidered. The sensitivity concludes with the sentence "These results suggest that determining the appropriate emission factor of market purchases will be critical going forward to accurately determine resource needs." This sentence, in the context of the broader sensitivity, is about being able to better specify the source and CO_2e intensity of market purchases.

There is a significant difference between noting the potential differences between the current unspecified rate actual emissions and advocating for DEQ to change its emissions methodologies. Nowhere in the above locations cited by RNW does PGE do the latter.

Finally, at this point PGE does not have a strong prediction regarding how the market unspecified emissions rate could change. It is plausible, as RNW speculates, that the growth in non-emitting generation could be offset by the competition for it. Which impact is larger, the growth in non-emitting generation or the demand for it, remains to be seen.

4.5.4 Power system modeling comparison

RNW provides a comparative analysis of how other organizations and utilities are conducting analysis to incorporate rapid decarbonization into electric power planning.[96] They draw insights from LADWP, SMUD, and the CPUC, discussing how their modeling is similar to, and different than, PGE's.[97]

PGE's response

As noted in the March 2023 Roundtable meeting, and in **Section 4.5.1, Sub-annual emissions modeling** of this document (among other locations), PGE is planning

[95] See LC80 Round 0 Comments: PGE Response at 46-47
[96] LC 80 Round One Comments of RNW at 27-29
[97] LC 80 Round One Comments of RNW at 27-29

energy/emissions modeling changes for the next CEP/IRP cycle and is appreciative of the information regarding other modeling approaches.[98]

4.6 Input assumptions

4.6.1 QF and community solar input assumptions

REC objects to the assumption that qualifying facility (QF) contracts do not renew and asks PGE to include information from other utilities when assessing renewal rates, to include information from the three historical PGE renewals that have occurred, and to include the Covanta Marion project as a QF renewal.[99] They also recommend using a 50 percent success rate for 202 projects (rather than 100 percent), noting the two projects that failed between the CEP/IRP filing and the Addendum, and noting historical failure rates support 50 percent.[100] Related to community solar, REC comments that PGE should only include energized community solar projects and only forecast future program growth as a CEP/IRP sensitivity.[101]

PGE's response

Regarding QF renewal rates, PGE has virtually no QF renewal history that would be reasonable to serve as a basis for forecasting a future renewal rate. The three projects that have renewed have a cumulate nameplate of 0.49 MW and are not usable proxies for estimating other QF renewals. We also find excluding the Covanta Marion project from the QF renewal calculations as appropriate. PGE does not treat every facility less than 80 MW as a QF, and Covanta Marion is not delivering power to PGE under a QF contract.

We also find using other utilities' renewal rates as inappropriate. There are vastly different conditions for QFs across different states and within Oregon, including, but not limited to: QF contracting process, avoided cost prices, standard QF terms and conditions, diverse interconnection processes, transmission constraints, and mix of on-system and off-system projects. In addition to these factors being different across utilities, and consistent with the March 30, 2023 Roundtable presentation, the number of QF contracts each utility holds, the technology mix for which they hold contracts for (e.g., PacifiCorp holds a large amount of legacy hydro), and the time period for which these contracts were entered into, are all vastly different.[102] Therefore, it is not appropriate to use the renewal rates of other utilities as a basis for PGE's renewal rate.

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[98] Please see the IRP Limitations and Areas for Improvement section starting on slide 40 of the March 2023 Roundtable
[99] LC 80 Round One Comments of REC at 2-8
[100] LC 80 Round One Comments of REC at 2-8
[101] LC 80 Round One Comments of REC at 9-11
[102] Please see slides 51-59 of the March 2023 Roundtable

We still find the 100 percent success rate for 202 projects to be appropriate. Although two facilities from a single developer terminated between the filed CEP/IRP and the Addendum, PGE does not believe that the outcome of projects from a single developer is sufficient additional information to change its position that a 100 percent success rate for Schedule 202's is reasonable and appropriate from a long-term planning perspective. In addition, given the size of the projects in scope for Schedule 202, PGE should be able to account for the fact that these developers should not be entering into speculative contracts, and that their ability to deliver should match the level of commitment.

Regarding community solar, PGE directs REC to OPUC Order 17-232, section "VI. ORDER", which in part states "When assessing load-resource balances in its integrated resource planning, an electric company must include forecasts of market potential for community solar projects..." PGE interprets this order, in part, as requiring a community solar forecast to be included in the adequacy model.

4.6.2 Hydrogen input assumptions

RNW provided multiple comments and questions on hydrogen modeling.[103] Regarding costs, they ask what cost components are used from a consultancy study, and if inflation and IRA credits are accounted for.[104] They also asked for PGE to ensure that any hydrogen produced is "green" hydrogen, recommend modeling hydrogen "availability" in locations with a renewable energy surplus, and suggest pairing hydrogen analysis with analysis of renewable overgeneration.[105] They also ask PGE to consider costs associated with incorporating hydrogen leakage technology into storage and pipeline cost estimates.

PGE's response

Specific to the hydrogen cost components from Monogrid and Hunter, reference case costs are based on the moderate scenario values with intermediate years based on interpolation.[106,107] Inflation is applied annually to escalate from base year values. Inflation Reduction Act tax credits are assumed for the production of hydrogen, construction of the energy storage facility, and resulting generation of non-emitting energy. As with other resources, tax credits are assumed to be monetized in the year generated.

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[103] LC 80 Round One Comments of RNW at 17-18
[104] LC 80 Round One Comments of RNW at 17-18
[105] LC 80 Round One Comments of RNW at 17-18
[106] Mongrid et al., "2020 Grid Energy Storage Technology Cost and Performance Assessment." Pacific Northwest National Laboratory. December 2020. Retrieved from: https://www.pnnl.gov/sites/default/files/media/file/Final%20-%20ESGC%20Cost%20Performance%20Report%2012-11-2020.pdf
[107] Hunter, et al., "Techno-economic analysis of long-duration energy storage and flexible power generation technologies to support high variable renewable energy grids." Retrieved from: https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3720769

PGE agrees that 'green' hydrogen must be generated using GHG free electricity and agrees that understanding the projected future time periods of clean energy surpluses could be useful when considering hydrogen production. Regarding the location of the hydrogen production facility, PGE is evaluating this comment given the ability to transmit power from clean energy resources to the production facility.

The current CEP/IRP hydrogen analysis is largely exploratory and non-actionable. Future analysis of hydrogen may, if appropriate, include additional details and costs associated with detecting and mitigating hydrogen leaks. We will work with stakeholders to develop appropriate resource characteristics and emissions accounting when considering hydrogen in future planning work.

4.6.3 AdopDER inputs

The Energy Advocates ask PGE to include in the AdopDER model specific Oregon low/moderate income incentives, specifically the Energy Trust of Oregon's Solar Within Reach Incentive and the Oregon Department of Energy Solar and Storage Rebate.[108] They note that inclusion of those programs would lead to a higher distributed PV forecast.[109] They also recommend the Commission require PGE to include those incentives in the AdopDER model for future work.[110]

PGE's response

PGE did update our solar forecasting methodology in the updated DER forecast provided in the Addendum to reflect higher incentives available to low- and moderate-income customers through Energy Trust's Solar Within Reach program offering. This decision was made based on feedback collected through the DSP regarding desire on the part of some stakeholders to see these incentives added to PGE's forecast methodology.[111] PGE acknowledges that this update should have been noted in the narrative write-up accompanying the DER forecast addendum.

4.7 Temporal granularity

4.7.1 Hourly analysis of the Preferred Portfolio

Staff express concern that PGE's modeling may not provide a realistic estimate of GHG emissions associated with portfolios due in part to temporal granularity limitations. Staff

[108] LC 80 Round One Comments of Energy Advocates at 7
[109] LC 80 Round One Comments of Energy Advocates at 7
[110] LC 80 Round One Comments of Energy Advocates at 7
[111] See Order 23-069 Appendix A pp. 11-12 available at: https://apps.puc.state.or.us/orders/2023ords/23-069.pdf

presents a draft of an hourly economic dispatch study which estimates GHG emissions associated with serving retail load using an approximation of PGE's Preferred Portfolio. Staff report that their initial findings forecast higher GHG emissions toward the end of the 2020's than PGE is forecasting. For comparison against their initial findings, Staff request that PGE conduct hourly dispatch analysis of the Preferred Portfolio under Reference Case conditions, that ensures load balance in each hour and tracks hourly dispatch, variable costs, and GHG emissions by resource as well as hourly market purchases and market sales. They request that PGE report annual portfolio costs and GHG emissions based on the simulation and that PGE provide transparency into how purchases and sales affect the GHG emissions associated with meeting load.[112] RNW make a related comment, indicating that PGE's current annual modeling framework lacks the temporal granularity to accurately account for GHG emissions. Accordingly, RNW suggests that PGE should adopt an hourly or systems-level analysis of its emissions target.[113]

PGE's response

PGE appreciates Staff's input into this topic, as emissions accounting is critical CEP/IRP analysis and determining the appropriate level of granularity for modeling is foundational to that effort. However, judgment is required whenever considering increasing the requirements in one area: increasing temporal granularity (or any other level of precision) can bring a sharper focus on the specific area but can also increase the time required to investigate individual components. When considering the magnitude of other analytical requirements, the additional time required could reduce the quality of this and other components of the plan.

Staff suggests it would be difficult to determine whether PGE has met specific requirements if PGE does not provide an energy analysis conducted at the hourly granularity. However, Staff does not explain why an hourly timestep is the appropriate unit of time for this modeling. While PGE agrees there are likely benefits to increasing granularity in its modeling (having identified this as a limitation in the March 2023 Roundtable meeting), PGE is unsure why the hourly timestep (and not any other) is the most appropriate for CEP/IRP analysis. Even after determining appropriate modelling resource allocation, PGE has concerns that many analytical difficulties are present when evaluating a model using an hourly timestep, as it

[112] LC 80 Round 1 Comments of Staff at 8-11
[113] LC 80 Round 1 Comments of RNW at 20-21 & 30

could potentially miss additional sub-hourly granularity and potentially lead to model overfitting.[114,115]

These concerns aside, PGE agrees with Staff that evaluating the resources included in the Preferred Portfolio in the PZM model (conducted in Aurora) could provide useful insight into both the feasibility of our plan and opportunities for modeling improvements going forward.[116] While the iGHG model was an important step in the development of this IRP (as it allowed for an appropriate accounting of emissions consistent with DEQ emission methodologies), there were many simplifying assumptions therein that should be tested and understood.

Inputting the set of resources contained in the Preferred Portfolio into the PZM and evaluating the hourly system position highlights the differences in estimating the dispatch of existing thermal resources. In the filed CEP/IRP the iGHG model separates the total thermal generation estimated in the PZM model into energy used to serve retail load and wholesale market sales. It does so on a yearly basis relying on the yearly plant average CO_2 intensities prescribed by the ODEQ for emissions reporting. However, as currently constructed the PZM uses thermal characteristics used in the MONET model, which include a minimum, maximum, and average heat rate for each unit.[117] The main question in this analysis is whether PGE is planning for sufficient non-emitting generation to meet emission reduction targets, and these differences prevent any direct comparisons between the emissions results from the PZM and iGHG model. However, by examining the expected hourly energy generation some insight can be gained into the limitations of PGE's current analytical approach. PGE interpreted Staff's draft analysis to be using this same approach.[118]

It is reasonable to expect differences when using the results from a longer timestep analysis in one that is shorter; judgment is needed to determine whether those differences are acceptable. When considering the hourly energy load-resource balance from a set of

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[114] An hourly could miss sub-hourly granularity. For example, if a generation resource disproportionately generates in the last 15-minutes of an hour, an hourly analysis could determine that the company was energy sufficient while operationally needing more generation resources. PGE does not believe the potential availability of the EIM could address these differences and/or mitigate concerns about the emissions implications of PGE's position.

[115] The CEP/IRP PGE uses individual generation shapes for incremental resources to provide the general characteristics of what can be expected on an average basis from the resource. The uncertainty in those shapes is important to consider. It would be inappropriate to believe that they forecast that for example at 2pm on August 3rd a SE Washington wind resource will be generating precisely 7.59% of its nameplate capacity, despite the shape identifying that production. Similarly, building a load-resource balance for that specific hour would put increasing reliance on that input; doing so could be informative, but the costs (measured in over-fitting analysis and time not doing other modeling) could also outweigh its benefits.

[116] For this analysis the Preferred Portfolio from the July 7th Addendum is used, though correcting for the 7 MWa underestimation of energy need mentioned below in **Section 6.2.4**.

[117] While emission rates could be adjusted to align the PZM with DEQ emission rates, PGE has believed there is benefit to retain the operational detail contained in the PZM (and MONET), accepting the resulting differences in emission forecasts.

[118] Assigning a positive market emissions rate for all hours in which PGE was short and then adding those emissions to the emissions associated with retained thermals and carbon content of market purchases.

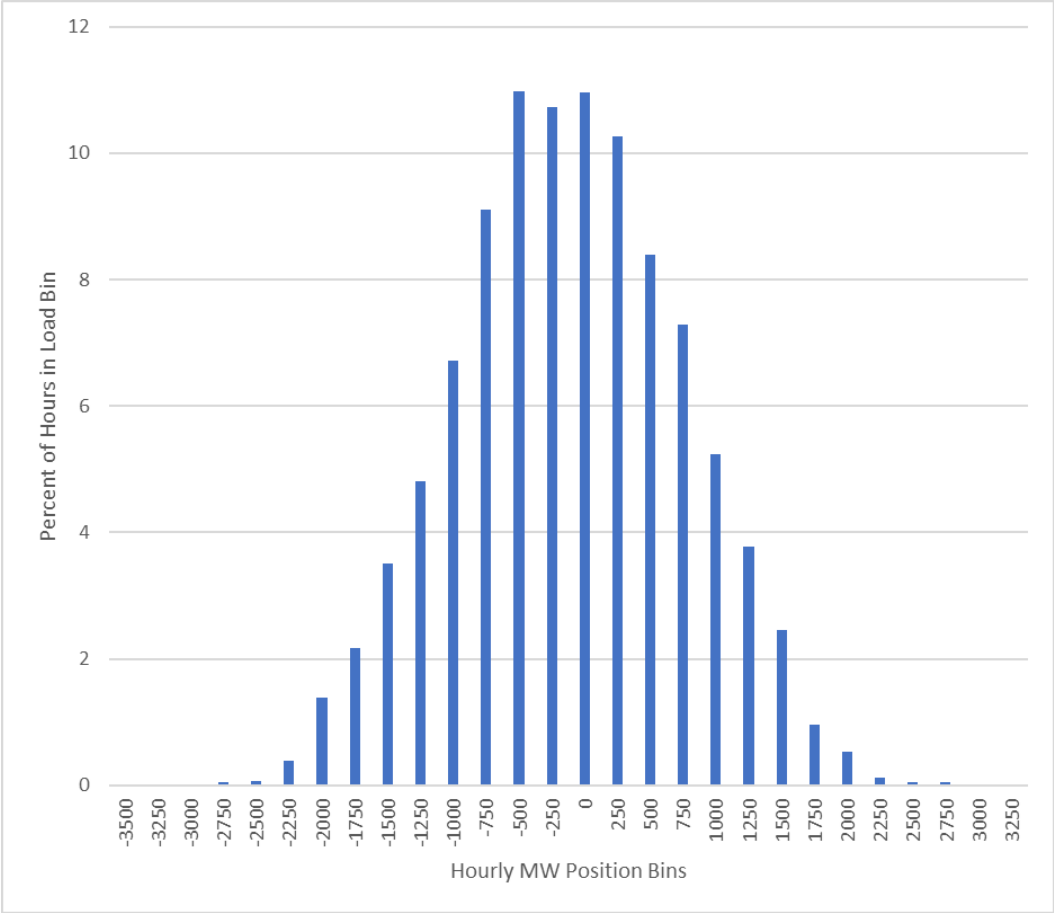
resources that are balanced at the yearly level, the difference between load and generation in each hour represents how long or short the company's expected generation is relative to its demand. These differences can be analyzed across different dimensions. Ideally, the distribution of those differences is symmetric and centered at zero (signifying on average a balanced system) with a variance within an acceptable level (suggesting sufficient market depth to cover the hours where the company is short). Additionally, in an ideal scenario there would be no seasonality (or other temporal influence) of that distribution.[119,120]

While the PZM estimates total economic dispatch of thermal units, the relevant question is whether PGE is sufficient using only generation kept for retail load. A challenge in this analysis is determining how that generation (as well as the assumed emitting net-market purchases) are allocated over the year. Using only economics to determine the timing of that generation (as well as all other PZM assumptions) and adding market purchases evenly throughout the year, the distribution of market position hours appears on average adequate (on average ~9 MWa long), with a standard deviation of ~858 MW. This distribution (displayed below in **Figure 4**) suggests a general agreement between the PZM and ROSE-E, the latter of which selected the set of resources in the Preferred Portfolio to meet that average demand.

[119] For example, if all hours where the company were short occurred around February and August (two months of higher market prices), this would suggest a difficulty in those times to procure sufficient non-emitting generation on the market and accordingly a difficulty in meeting emission reduction targets (as the company would be forced to procure energy with associated emissions).

[120] Market prices are another consideration. A best-case scenario would be if the company was forecast to be long (and short) in periods of high (and low) market prices.

Figure 4. Initial distribution of energy position hours



While the confirmation of model estimation is encouraging, it does not by itself address Staff's concern that focuses specifically on the emissions implications of short hours. Before addressing this though it is useful to consider two questions posed by this initial naive analysis concerning the allocation of generation with associated emissions.

Should the thermal generation associated with retail load be used in hours in which PGE is already long?

There are 2,752 hours in the analysis above in which PGE is long before thermal generation, and in 362 of them thermal resources are generating due to the relative economic and operational forces in those hours. Since this generation is designated for serving retail load it makes sense in this analysis to reallocate that ~148 GWh to hours in which PGE is estimated to be short. However, the operational constraints that are a feature of the PZM complicate this analysis. It is not straight forward to simply limit thermal generation in hours of sufficiency while maintaining the desired generation levels, especially in the short timeline provided in LC 80. This is a critical area of development for PGE, as understanding how emission and operational

constraints interact (especially under forecast uncertainty) will be necessary to develop a resource plan that maximizes reliability and power costs while meeting emission reduction targets. For this analysis PGE considered a variety of outboard heuristics (described below) that achieve the goal of reallocating that generation but miss the operational detail available in Aurora. The company will prioritize this work as it continues to develop its modeling capabilities.

How should emitting market purchases be distributed across the year?

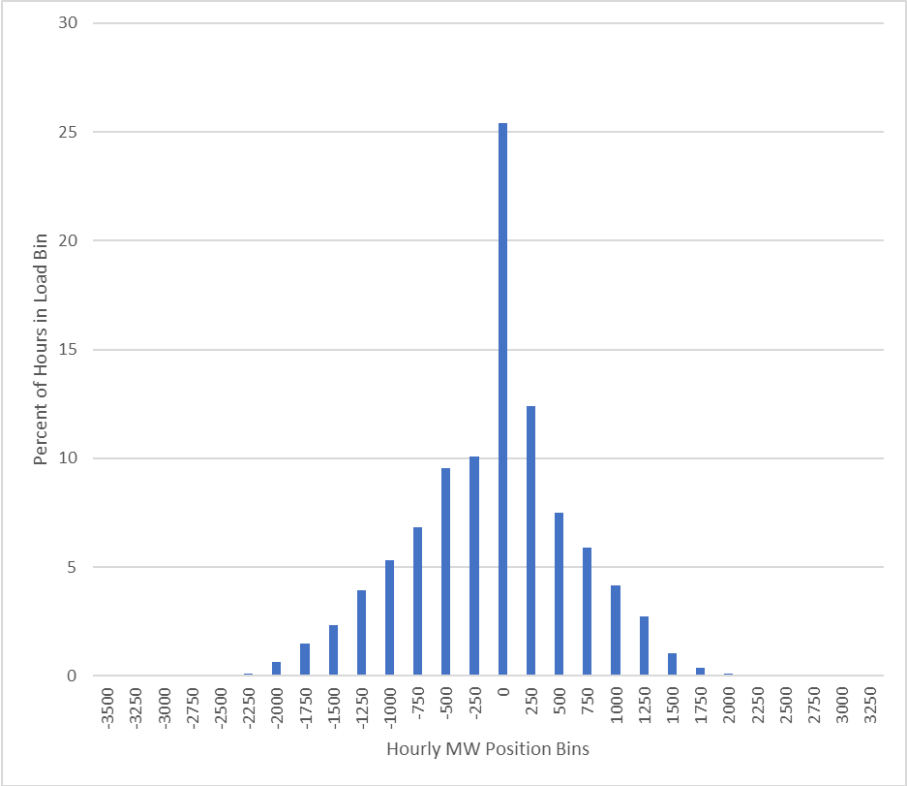
Market purchases with associated emissions are determined by the iGHG model and based on historical purchase levels, historical ratios of energy retained for retail load service, and the relevant emissions glidepath.[121] The above distribution allocated those 1,465 GWh equally across the year (adding 167 MW in each hour). However, it is reasonable to assume that those market purchases with associated emission would not occur in hours in which the company was long. There are a variety of methods to allocate these purchases: size or timing of the short position, market prices (high or low), known peak times, operational experience, etc. PGE evaluated several below, but determining the most appropriate methods will be foundational to understanding how PGE can use the market to address intermittent generation.

One approach to address the questions above would be to sum the total generation in long hours with the total market purchases and redistribute it across hours in which PGE was short.[122] Doing so while following Staff's assumption that non-emitting generation can be purchased in hours in which market prices were non-positive leads to the histogram of energy position hours displayed in below. Noting the y-axis differences between **Figure 4** above, **Figure 5** below displays the increase in the number of hours in which PGE is perfectly balanced (as the thermal generation in otherwise adequate hours is moved to short hours).

[121] PGE used this approach in the CEP/IRP as it is based on historical data and consistent with our treatment of energy and emissions of PGE owned resources.

[122] As noted above, ideally this would incorporate operational constraints modeled in the PZM as not all thermal generation can be moved from long to short hours. However, given the limited time available for these Reply Comments this redistribution is done outboard, and accordingly misses some operational fidelity that otherwise would be expected using Aurora. This might not be an unreasonable simplification, as the thermal generation in this analysis is only that associated with thermal load. There is expected additional thermal generation (for wholesale sales), and the ability to change from market sales to retail load is very likely much more agile than the operational constraints of an individual unit. For example, while a thermal likely cannot generate 100 MW in one hour than 50 MW the next, PGE likely can run the plant in both hours at 100 MW and sell 50 MW in the second hour.

Figure 5. Revised histogram of energy position hours



Another approach would be to instead move the excess thermal and market generation to short hours with higher market prices.[123] Assuming higher market prices signify a lower availability of non-emitting generation, allocating the market generation to higher-priced hours would minimize the likelihood that PGE would be reliant on market purchases with associated carbon content. The resulting distribution of energy position hours is displayed below in **Figure 6**. It shows a larger number of hours where PGE is perfectly balanced than above, and an uneven distribution between short and long hours. This further highlights the importance of understanding the conditions of hours where PGE is short.

[123] Reallocating this generation leads to hours where PGE is forecasted to be long. For example, instead of allocating 50 MW to an hour that PGE was short by 20, that excess 30 MW could be reallocation to a different hour. This process is repeated once in the results that created **Figure 4**, but in Excel it could be continued further resulting in fewer shorter hours and more balanced hours. The operational considerations mentioned above limit the usefulness of this formula-based approach.

Figure 6. Reallocating generation and market purchases to above-average priced hours

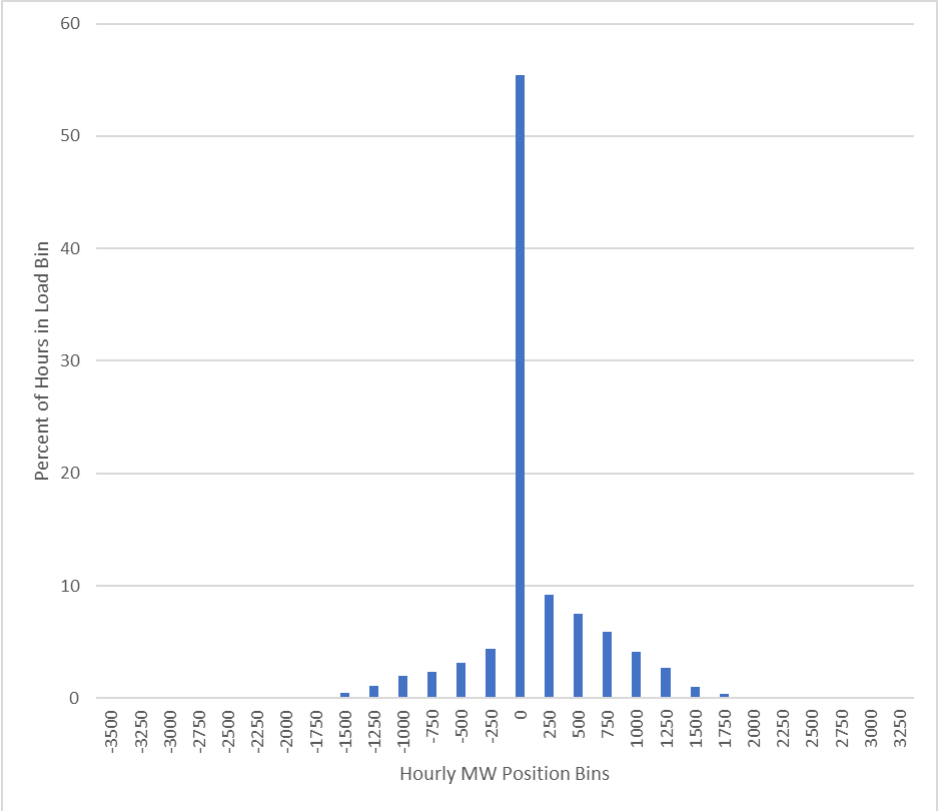
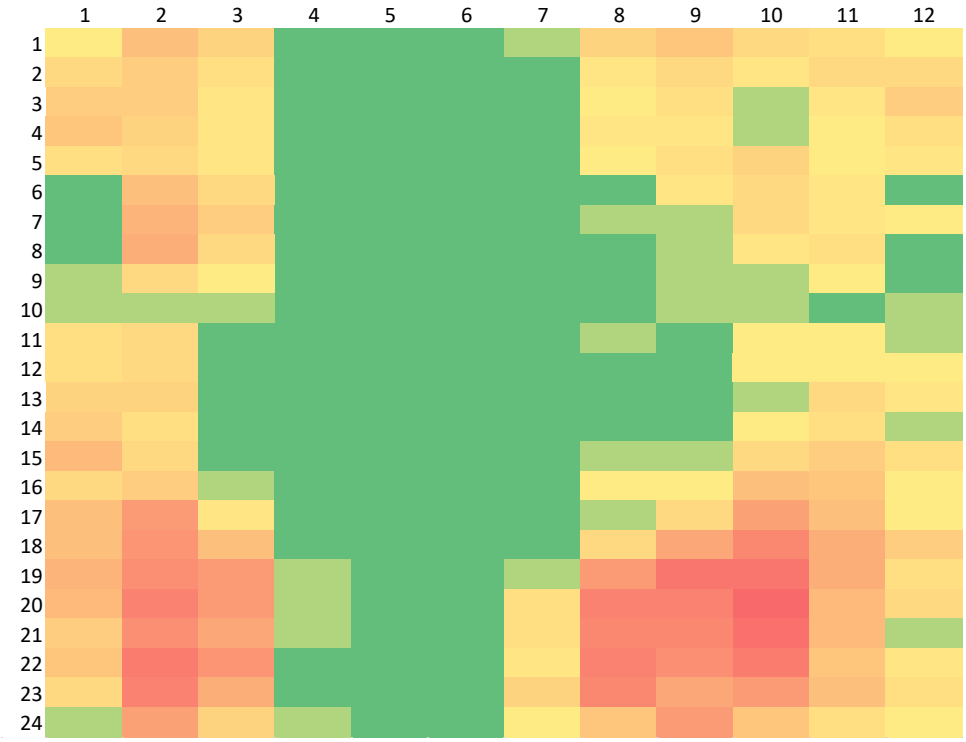


Figure 7 below is a 12x24 heatmap that displays the count of hours where PGE is estimated to be short under the scenario described above.[124] This heatmap is notably different than that describing capacity need, which shows need in peak hours.

[124] While this figure does not display the size of those impacts, a figure that instead displayed the average sizes of shortness rather than the count appears very similar.

Figure 7. 12x24 heatmap of number of short hours in expected average conditions



There are additional considerations that PGE is investigating through this work. Currently, battery storage systems are modeled to pursue energy arbitrage: the storage will charge at the lowest price hours and discharge at the highest price hours. Storage resources are limited to charge and discharge 365 times a year. While only focusing on economics, the storage operation assists PGE's energy position by assuming a strong negative correlation between PGE's energy position and market prices (being long when market prices are low and vice versa). However, this correlation is likely not perfect, and it seems likely that changing the orientation of battery storage to move energy more directly from hours of surplus to hours of deficit would reduce the number of hours estimated to be short. Similarly, specifying the behavior of hybrid resources could be influential to results. Currently the PZM operates hybrids like equivalently sized stand-alone solar and storage resources, but there are some situations where this will not be the case.[125] Resource adequacy modeling also is directly relevant for this evaluation. PGE followed direction from both Staff and the Commission that capacity in the CEP/IRP should be evaluated under expected weather, plant operations, and hydro conditions (referred to as a C-50 scenario). This choice (adopted by the Commission in Order 22-446) signified that PGE would model resource adequacy under average conditions. Increasing this choice of C-level would also change the quantity of

[125] For example, in the recent solar and storage QF tariff filed in UM 2000 hybrid resources are required to charge their storage using the associated renewable resource and discharge their storage during pre-determined and fixed hours.

thermal generation available for serving retail load and would affect the quantity of hours that PGE is both short and long to the market. Finally, this analysis highlights a need to better understand PGE's approach to determining hourly load. In the modeling process employed in both the 2019 IRP and the 2023 IRP/CEP, PGE applies an hourly shape to the monthly corporate load forecast to create an hourly load profile. Whether this month-to-hour conversion appropriately captures the expected average variations in demand will be highly influential to results.[126]

Once these methodological questions are settled Staff's main concern can be addressed, as the results described above suggest that it is reasonable to assume that any hourly histogram of hourly energy position would have some hours where PGE is short. The yearly iGHG model in the filed CEP/IRP utilized an assumption that PGE was able to buy (and sell) non-emitting generation at times which it was short (and long).[127] For analysis conducted at a yearly interval this seemed appropriate given the uncertainty involved and the alignment with the yearly timestep of the portfolio analysis model. However, PGE understands Staff's draft analysis to assume no availability of non-emitting generation (save for non-positively priced hours). If this assumption is correct, then both PGE and Staff's draft analysis are in alignment pointing to a need for an increased quantity of non-emitting generation to be acquired between now and 2030 to ensure compliance with HB 2021 under expected average conditions. If it is not, then this analysis indicates that meeting emission reduction targets with the Preferred Portfolio's set of incremental resource additions is possible under expected conditions.

Unfortunately, neither analysis provides sufficient insight into the availability of a market for non-emitting generation. PGE's simulated market prices are extremely sensitive to the resource buildout employed. Following the 2019 IRP, the WECC-wide model was based on a forecasted set of resource additions created by the consultancy WoodMac which is based on projections of technology, demand, and relevant policy. However, unlike the previous IRP PGE did not evaluate different resource buildouts. Understanding the differences across a range of WECC resource buildouts (and the resulting effects on forecasted market prices) will be critical going forward to understand the potential for PGE to lean on the market under times of lower intermittent generation. Further, the critical takeaway from this work would be an understanding of the availability of non-emitting generation, which will require a better analysis of market demand as well. It is and will continue to be an area of active exploration for PGE.

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[126] One additional consideration evaluated by Staff was PGE's choice of which thermal generation to retain. PGE does not believe this is an appropriate sensitivity as it would select generation most favorably for the Company (akin to the resource 'shuffling' mentioned unfavorably by RNW) and does not represent a realistic operational strategy when existing thermals are expected to be utilized for maintaining resource adequacy on PGE's system.

[127] Further, this assumption stated that the benefit from the sales equaled the cost of purchasing the non-emitting generation.

The 2023 CEP/IRP took major steps to modify its modeling process to better align with the emissions accounting methods employed by the ODEQ. Those emissions methodologies are long standing, serve as the basis of the state's GHG policy and goals, and now have the added advantage of requiring independent third-party verification. PGE notes however that given the accelerated complexity of long-term planning, the increasing number of topics of interest, and increased expectations from stakeholders and the Commission, there are very few areas of analysis in the filed CEP/IRP that cannot be improved. However, while PGE agrees that much work is needed to better understand the dynamics of expected generation, emissions, and market interactions, the Company disagrees that Staff cannot verify whether PGE's plan meets the expectations set forth in ORS 469A.420(2) and in Order No. 22-446. PGE believes it does, with the caveat that all results are based on its current long-term modeling process. This caveat is critical, and suggestive of the need for PGE to continue to invest in the development of its emission accounting process and assumptions about market availability. Temporal granularity will be an integral component of both. Considering these uncertainties, PGE is less confident than Staff that an hourly timestep (and not say a sub-hourly or monthly approach) is the most appropriate level of detail required to create a long-term plan with significant policy and economic uncertainty, finite modeling resources, and competing questions of interest. However, PGE is eager to work with Staff and stakeholders to work on these questions as we continue the improvement of our modeling process for this and future regulatory proceedings.

4.7.2 Ancillary services

RNW expresses concerns that PGE may be underestimating GHG emissions from the existing thermal fleet associated with operating to provide ancillary services because of lack of temporal granularity in current modeling. RNW says that PGE should analyze the ancillary services role currently served by its thermal fleet and identify the investments necessary to reduce reliance on thermal resources for voltage, frequency, inertia, and other power flow requirements.[128]

PGE's response

As noted in **Sections 4.5.1, Sub-annual emissions modeling** and **4.7.1, Hourly analysis of the Preferred Portfolio**, PGE agrees that there are limitations associated with the temporal granularity of our current modeling capabilities and is committed to taking steps to improve our capabilities in the future. Additionally, PGE agrees with RNW that there is a significant need to improve PGE's modeling of its need for ancillary services. PGE identified these limitations and expressed the goal to improve our capabilities in the future in March 2023

[128] LC 80 Round 1 Comments of RNW at 25 & 29-30

roundtable meeting. As we note in **Section 4.7.1**, we believe that despite the need to continue to improve our modeling capabilities, the modeling in the CEP/IRP demonstrates a resource acquisition strategy that allows us to comply with HB 2021 emissions requirements.

Chapter 5. CBRE and CBIs

5.1 Informational CBIs

RNW and Energy Advocates recommend the inclusion of actions that focus on environmental and energy justice within PGE's Action Plan. Additionally, both stakeholders reiterate their preference to be able to differentiate CBI progress resulting from CEP-driven actions as distinct from other actions taken by PGE. [129,130] Relatedly, Staff notes that it is unclear how several CBI categories are directly impacted by CEP/IRP analysis and encourage PGE to make stronger linkages going forward.[131]

Several parties provide feedback on the specific CBIs included in PGE's list of iCBIs. Staff, Energy Advocates and RNW all reiterate previous recommendations concerning environmental iCBIs and reflection of tribal priorities in iCBIs. Staff offers more detailed considerations to improve clarity and usability of certain CBIs.[132] And RNW expresses a desire to learn more on any work PGE has conducted to date to establish iCBI baselines.[133]

CUB expresses desire to further understand how the CEP/IRP were in the public interest, as it relates to environmental and health benefits, and reliability and resiliency of the system.[134]

PGE's response

The 2023 CEP/IRP represents PGE's first attempt at including informational CBIs (iCBIs). The development and integration of CBIs within portfolio analysis occurred within a short period of months given the timing of finalized regulatory expectations and plan filing dates. PGE is therefore still learning and should be able to create a stronger understanding between actions taken and the reported iCBIs as we evolve.

CEP/IRP actions represent broad resource needs and targets. Specific actions that impact customers including EJ communities occur downstream during program planning and resource procurement. For example, the CEP/IRP actions state the targets to procure CBREs

[129] LC 80 Round 1 Comments by Renewable Northwest at 52
[130] LC 80 Round 1 Comments by Energy Advocates at 14
[131] LC 80 Round 1 Comments by Staff at 16
[132] Id.
[133] LC 80 Round 1 Comments by Renewable Northwest at 52
[134] LC 80 Round 1 Comments by CUB at 6

but not specific CBRE project proposals. Hence the effectiveness of those CBREs in mitigating energy burden or providing resiliency will be established through the resource acquisition process. Thus, PGE does not believe it is appropriate to include specific iCBIs as actions within the Action Plan in this CEP/IRP.

Regarding the attribution of actions to CBI progress, PGE 's approach in the CEP/IRP, through our engagement processes, was to prioritize and select accessible but necessarily broad iCBIs. PGE believes this approach aligns with the intent of the CEP expectations and is consistent with feedback provided by Energy Advocates in the UM 2225 process. An implication of this approach is that CBIs will be impacted by a myriad of factors both within and out of scope of CEP/IRP actions, and even the scope of utility actions. PGE is open to trying to isolate the impact of its CEP actions, once the iCBI approach is formalized through the acknowledgement of the CEP/IRP, on the iCBIs but believes the broad nature of the iCBIs may hinder our ability to isolate the impact of CEP actions from other factors that impact iCBIs, including other company actions.

PGE appreciates the reiteration by stakeholders to include an environmental iCBI and an iCBI specific to tribal communities and hopes to dispel the Energy Advocates' perception that PGE is resistant to consideration of this suggestion. PGE does not currently have the capacity to engage with communities to inform development of specific environmental and tribal iCBIs for this CEP/IRP. However, PGE will develop iCBIs in both areas by working with stakeholders including the community, to review prospective iCBIs including those listed by stakeholders in these comments before determining which environmental and tribal iCBIs are most appropriate to include and track in the next planning cycle. PGE will consider including these new iCBIs as part of reporting in the next CEP/IRP.

Regarding iCBI baselines, though some data may be available or tracked and reported for other purposes, PGE has not begun an analytical process to develop baselines for iCBIs. Following OPUC acknowledgement of our CEP/IRP, PGE intends to begin the work of specifying iCBI data sources and developing baselines.

Addressing CUB's comments, PGE notes that emissions reductions achieved by our CEP/IRP actions will contribute to public health and environmental benefits across our state and region. Furthermore, projects deployed through implementation of CBREs and customer actions have high potential to provide very localized health and environmental benefits. Rather than define and estimate the value of each potential benefit area in advance, we intend to use the CBI process to provide a snapshot of these benefits over time and use input from community groups to inform areas of high importance to focus on. PGE has accounted for these benefits in a generalized approach via both rCBIs and pCBIs. PGE chose this approach to ensure the CEP/IRP balances the time available to meet these requirements along with an approach that is not overly prescriptive and enables downstream resource procurement to consider a wide range of options. Regarding iCBI development, PGE worked

with communities to prioritize the list of iCBIs, as described in CEP/IRP Section 14.2.3.2 CBI community engagement. We expect the iCBI list will be a primary input within downstream procurement activities, where further community engagement will influence how these iCBIs factor into resource acquisition process.

PGE's approach to reliability and resilience has been informed by communities through PGE's DSP process, OPUC's UM 2225 process, and Learning Labs prior to the CEP filing, as detailed in the CEP/IRP Chapter 13. Resilience is a broad objective, with implications on numerous aspects of PGE's planning and operations. PGE has taken significant steps to consider resilience within the scope of this CEP/IRP and we expect our approach to continue to evolve and mature moving forward. The inclusion of resilience-focused iCBIs and our commitment to use CBIs to inform resource acquisition decisions for CBRE resources and customer programs are ways in which the CEP/IRP will ultimately affect customer and community resilience.

5.2 CBRE community engagement

On the topic of CBREs and community engagement, RNW reiterates their Round 0 comments identifying a need for more capacity building and resources in under-resourced communities for them to gain experience and an ability to engage in planning and building CBRE projects.[135]

PGE's response

PGE appreciates RNW's acknowledgement of the Company's plans to engage community members and other environmental justice representatives in the development of the CBRE acquisition process and scoring matrix. We expect CBRE acquisition to be an iterative process. PGE is looking to work with Staff and other stakeholders to define the best way to pursue the additional capacity building and resources needed to gain experience in these under-resourced communities. Ultimately, PGE views this as a collaborative process that will help in identifying the best way to build these capabilities.

5.3 Maximum CBRE Potential

Related to the topic of CBREs, Energy Advocates requests additional explanation surrounding how PGE determined 155 MW as the maximum amount of realistic and achievable CBRE potential in the Action Plan.[136]

[135] LC 80 Round 1 Comments by RNW at pp. 53
[136] LC 80 Round 1 Comments by Energy Advocates at pp. 9

PGE's response

PGE conducted a community lens potential study (described in Section 7.2 of the CEP/IRP) that identified 155 MW of technical achievable CBRE potential for inclusion in portfolio analysis in this first CEP/IRP. The high-level steps PGE followed to determine this amount for inclusion in portfolio analysis were:

a) Review the literature and past feedback from community participants gathered through the Distribution System Planning process

b) Define the proxy CBRE resource types for inclusion in portfolio analysis (Standalone community-scale solar, community resiliency microgrids, and in-conduit hydro)

c) Develop quantitative assessments leveraging multiple sources, including PGE's AdopDER model, published municipal climate action targets, Energy Trust project pipelines, and published national lab studies such as the Oak Ridge National Lab in-conduit hydropower potential study.[137]

Each resource's MW buildup is generated following this process and represents PGE's best assessment of a realistic and informative CBRE potential, given the specific modeling delineations discussed in Section 7.2 of the CEP/IRP. As PGE gains more experience with these new resource types, we expect to revisit and refine this process (also described in Section 7.2.4 of the CEP/IRP).

5.4 CBRE acquisition

On the topic of CBRE acquisition, AWEC comments that PGE justified the acquisition of CBRE resources using arbitrary and unsubstantiated benefits created by reducing the cost of CBRE resources by 10 percent.[138] They suggest this led to acquiring more expensive resources than required and PGE should leverage its available community solar and distributed energy studies to create a cost reduction for CBRE resources.[139] Additionally, AWEC recommends that PGE's only actions to acquire CBRE resources should be tied to the small-scale renewables requirement set forth in ORS 469A.210.[140] They specifically suggest evaluating biomass resources to meet this mandate as they were previously excluded based on feedback received from PGE's community engagement process.[141] Lastly, AWEC suggests that PGE allocate above-market costs of CBRE resources solely to the communities where the

[137] In-conduit hydropower potential study from Oak Ridge National Lab is available at: https://info.ornl.gov/sites/publications/Files/Pub176069.pdf
[138] LC 80 Round 1 Comments by AWEC at pp. 13
[139] LC 80 Round 1 Comments by AWEC at pp. 13
[140] LC 80 Round 1 Comments by AWEC at pp. 14-15
[141] LC 80 Round 1 Comments by AWEC at pp. 14-15

resources are located, if these resources are selected, until these resources are necessary to meet a statutory or regulatory mandate.[142]

PGE's response

PGE agrees with AWEC that the 10 percent cost reduction value for CBRE resources is essentially arbitrary, which was discussed in more detail in Section 7.1.3 of the CEP/IRP. This value was chosen to serve as a representative of the potential benefits CBRE resources would offer given the lack of availability of better information surrounding specific resource characteristics. Additionally, PGE finds it reasonable to believe that the removal of the 10 percent cost reduction would not have any impact on CBRE resource selection and the resulting portfolio. Accordingly, PGE believes AWEC's concerns to be unsubstantiated based upon current evidence. At this point, PGE is not proposing to apply the 10 percent factor in the context of acquisition of any individual CBRE project, for which more project-specific community benefits would be applicable. PGE notes that HB 2021 defines CBREs in such a way that small scale renewables do not necessarily fulfill the broader goals of CBRE; all CBREs, as applied in PGE's CEP/IRP, are small-scale renewables but not all small-scale renewables are CBREs.

Addressing AWEC's comments on biomass resources, PGE reiterates that community feedback informed the Company's decision to exclude biomass resources. Through a stakeholder and community engagement process PGE received direction that biomass resources should not be considered as non-emitting due to their associated greenhouse gas emissions. Therefore, PGE chose not to include biomass resources as potential options within the IRP portfolio modeling.

5.5 CBRE Trade-offs

Staff requests PGE submit a supplemental CBRE analysis that better addresses the costs and opportunities resulting from offsetting energy generated using fossil fuels with community-based renewable energy required in HB 2021.[143] Additionally, Staff suggests PGE perform additional CBRE portfolio analysis to provide more information surrounding when CBRE additions are no longer low-regrets actions or insights into tradeoffs of different levels of CBREs in the portfolio.[144]

[142] LC 80 Round 1 Comments by AWEC at pp. 15
[143] LC 80 Round 1 Comments by OPUC Staff at pp. 19
[144] LC 80 Round 1 Comments by OPUC Staff at pp. 20

PGE's response

PGE understands the confusion surrounding the required analysis of the costs and opportunities resulting from offsetting fossil fuel generated energy with community-based renewable energy. Although it was not explicitly stated as fulfilling the HB 2021 requirement, the Company did evaluate the ability of CBRE resources to offset thermal generation. This was not done as an additional independent analysis but instead within the existing portfolio analysis; each portfolio can choose CBRE resources over thermal resources if the capacity expansion model (ROSE-E) determined it was a lower-cost solution. However, the maximum quantity of CBRE resources were generally already selected either based on portfolio construction and/or economics. As stated in Section 11.4.3.1 of the CEP/IRP, the optimized CBRE portfolio selected the full amount of CBRE resources available and had the lowest costs and risks, equivalent to the portfolio forcing the full amount of CBRE resources.

Accordingly, PGE never found an opportunity for CBREs to offset thermal generation due to the simple conclusion that there was never any available CBRE resource beyond that which was selected based on economics. However, PGE notes that in portfolio analysis the Company never saw additional thermal generation curtailed below the specific levels set by the relevant emission reduction glidepath. This indicates that the net costs of thermal generation generally lower the total LCOE available by CBREs (or any other available generation resources), which supports the consistent finding that there are very few opportunities to increase pace of decarbonization while also decreasing costs.

Finally, addressing Staff's request for additional CBRE portfolio analysis assessing different levels of CBRE in the portfolio, PGE is unsure of the added value of evaluating additional CBRE resources past the maximum quantity determined to be available in PGE's Community Lens Potential study. Current portfolio analysis has defined CBRE portfolios evaluating varying levels of CBRE resources within the maximum available quantity. Further work is needed to determine the precise quantity and associated pricing of CBRE resources available, but PGE believes that portfolio analysis is most meaningful when it uses the determined quantity strictly as an input.

5.6 Portfolio CBIs

Staff expresses concern that PGE's current Portfolio CBI (pCBI) approach does not allow comparison of all relevant community impacts and does not have an impact on portfolio selection. To address these concerns, Staff recommends that PGE provide an interim pCBI that captures the different benefits across all resource types across all portfolios. Staff recommends that the quantity of energy efficiency and microgrid CBREs in each portfolio be used as an interim pCBI scoring metric until the PGE can identify more metrics for quantifying important impacts of its potential actions on communities. Staff also recommends that PGE update portfolio scoring to express the pCBI in dollar terms. If the recommended analysis

cannot be provided, Staff recommends that PGE discuss opportunities and barriers to meeting the request.[145]

PGE's response

PGE understands Staff's request to be looking to gain more information on the trade-offs between community benefits and costs. While PGE agrees that this is an important dynamic to characterize, portfolio analysis (as constructed) has suggested that maximizing community benefits and minimizing costs involve the same actions. Staff's suggestion of including an interim pCBI that identifies differing levels of community benefits for non-CBRE resources does not seem appropriate at this point because its inclusion would not impact portfolio analysis results and would not provide useful insight without significant input redevelopment and additional methodological refinement.

As noted in **Section 5.1, Informational CBIs**, this CEP/IRP was PGE's first attempt at incorporating CBIs and included an interim approach developed in a short amount of time. PGE has neither the experience nor expertise to meaningfully quantify dollar values for the different benefits different proxy resources (let alone individual projects) may have on communities. PGE does not believe it can develop these estimates with any precision in this docket. Furthermore, efforts to assign dollar values to specific benefit streams and apply resulting net benefits to portfolio optimization would have implications for other cost-effectiveness analysis overseen by OPUC, further underscoring the need for a robust process.

Instead of updating portfolio analysis with the pCBI expressed in dollar terms, PGE proposes beginning a process to quantify pCBIs and incorporate them into portfolio analysis by holding workshops with a third-party mediator to elicit stakeholder input and engaging a consultant with the necessary expertise to develop a more sophisticated approach. The Company will work with Staff and stakeholders to create this process going forward.

Chapter 6. Portfolio analysis

6.1 CBREs & DERs

Energy Advocates recommends that PGE run a model sensitivity with a higher adoption of CBRE and distributed-generation resources (DERs), specifically requesting that PGE model a portfolio that results in selection of 125 percent of the maximum stated CBRE potential used in portfolio analysis.[146] In a similar comment, NewSun requests analysis of additional quantities of CBREs, suggesting that PGE has not adequately addressed CBRE technical

[145] LC 80 Round 1 Comments of Staff at 15-16
[146] LC 80 Round 1 Comments of Energy Advocates at 9

achievable potential and requesting modeling of either an uncapped quantity of CBREs or up to 125 percent of the potential that PGE assumed in portfolio modeling.[147] NewSun also suggests PGE should run a model for DERs up to their achievable potential.[148]

PGE's response

The quantity of DERs and CBREs made available for selection in portfolio modeling was determined based on PGE's expectations about the availability of those resources.[149] As noted above, PGE does not believe conducting analysis on quantities of DERs and CBREs greater than are expected to be available would produce an actionable portfolio or offer particularly meaningful informational value. Accordingly, PGE is prioritizing other analyses for these Reply Comments.

Regarding CBREs, analyzing quantities beyond what is expected to be available would only provide value to the extent that the potential study is inaccurate. Results from the filed CEP/IRP and the Addendum showed that selection of the full amount of CBREs available reduces portfolio costs. Given the transmission and emissions constrained modeling environment, it is reasonable to expect that further analysis in which additional quantities of CBREs were available would find that selection of the incremental CBREs would further reduce portfolio costs. PGE believes upcoming efforts to acquire CBREs will provide important insights into their costs and availability that can be incorporated into future planning.

Regarding modeling of additional quantities of DERs, portfolio analysis in the CEP/IRP and Addendum has already shown that not all DERs made available to the model are selected, so making more available beyond the quantity used in modeling is not necessary. Specifically, 100 percent of non-cost-effective demand response is available and never selected, and less than 100 percent of EE is selected when available, so making additional quantities of either available would not change portfolio results.

6.2 Model specifications

6.2.1 Need Futures

Energy Advocates asks for clarification on where analysis of High and Low Need Futures can be found.[150]

[147] LC 80 Round 1 Comments of NewSun at 9-10
[148] LC 80 Round 1 Comments of NewSun at 10-11
[149] See **Section 5.3, Maximum CBRE Potential** for CBREs and PGE's DSP for DERs.
[150] LC 80 Round 1 Comments of Energy Advocates at 10

PGE's response

The list provided by Energy Advocates in their comments shows the set of 40 portfolios analyzed in the CEP/IRP. Each of the 40 portfolios is modeled across three Need Futures (Reference, High, Low). Need futures describe forecasted system need under a range of assumptions about load growth, distributed energy resources and market assumptions.[151,152] They are used in portfolio analysis to determine the robustness of proposed resource additions to a range of potential energy and capacity need conditions. For simplicity and clarity, the results that PGE has presented and described in previous IRPs, this CEP/IRP, and the July 7th Addendum mainly focus on the Reference Need Future, though resource buildouts and resulting costs are available for each need future and can be provided if helpful.[153]

6.2.2 Colstrip exit

Energy Advocates recommends that PGE model early Colstrip retirement in 2027 and modify the Action Plan accordingly.[154] Energy Advocates claims that keeping Colstrip in the portfolio will result in an underinvestment in clean energy. This reasoning is based on a dispute with PGE's modeling approach in which all else equal, Colstrip's presence in the portfolio reduces the amount of GHG-emitting energy that can be retained for retail sales. Energy Advocates cites the costs associated with complying with the EPA's proposed Mercury and Air Toxics Standards (MATS) as a factor that will drive early shutdown of the plant. Similarly, Staff states that it is unclear whether the inclusion of Colstrip in the portfolio beyond 2025 appropriately balances cost, risk, the pace of GHG reductions, and community impacts because no early exit portfolio was analyzed.[155]

PGE's response

PGE owns a minority 20 percent share in Colstrip Units 3 & 4 and cannot act unilaterally on operational decisions or the exit/closure of either Colstrip unit. The potential impacts of regulatory actions such as MATS on the outcomes of the plant do not change this. As a result, a portfolio in which Colstrip exits the portfolio prior to 2029 would not be considered actionable by PGE. For IRP planning purposes, PGE makes the modeling assumption of continued off-taking of power from Colstrip 3 & 4 through 2029. If a decision is made by all

[151] Portfolio analysis evaluated portfolios across a range of 351 total future scenarios based on the combinations of 3 futures for need, 13 futures for price, 3 for hydro condition, and 3 for technology cost.
[152] For addition description of Need Futures, see Section 4.2 of the 2023 CEP/IRP. Available at: https://edocs.puc.state.or.us/efdocs/HAA/lc80haa8431.pdf
[153] Portfolio analysis outputs provided in LC 80 AWEC DR 039 Attachment B contains results for all three Need Futures, for all portfolios.
[154] LC 80 Round 1 Comments of Energy Advocates at 13
[155] LC 80 Round 1 Comments of Staff at 11

Colstrip parties that results in a planned shutdown prior to 2029, PGE will update modeling assumptions regarding the plant accordingly.

From a modeling perspective, when Colstrip is removed from the intermediary GHG model PGE can retain more energy from emitting resources (because of the lower emissions rates of natural gas plants), which reduces the need for energy from incremental non-emitting resources in those years. The Action Plan annual acquisition target is based on the year 2030 energy need, which does not include Colstrip. While removing Colstrip early may impact portfolio analysis it will not impact Action Plan acquisition recommendations and it would therefore not provide useful information to guide decision-making about resource acquisitions at this point.

6.2.3 Clean capacity glidepath

In related comments, RNW and Staff express concern with risk associated with the rate of capacity additions in the Preferred Portfolio. RNW suggests PGE incorporate a clean capacity glidepath within portfolio modeling to smooth the transition away from GHG-emitting resources in the portfolio and prevent the risk of "hockey stick" transitions in resource additions at critical milestones.[156] Staff expresses concern with large capacity additions being made in the years leading up to the large increase in capacity need that occurs in 2040. Staff recommends that PGE provide additional analysis that decreases the annual capacity limit imposed in portfolio modeling to explore the cost and risk implications of spreading the additions of capacity to meet 2040 needs across more years.[157] Staff also asks that PGE explain how the capacity additions in the Preferred Portfolio have informed the long-term decarbonization strategy as it relates to acquiring non-emitting capacity over time.[158]

PGE's response

PGE's portfolio analysis smooths the addition of resources to prevent unrealistically large and risky resource additions (the 'hockey stick' effect described by RNW) in the key target years of HB 2021 GHG emissions reduction goals.

This is done in two ways. First, the linear decarbonization glidepath necessitates that renewable resources be added to offset GHG-emitting generation continually throughout the planning horizon. While the driver of these resource additions is energy need rather than capacity need, they do provide capacity and represent not insignificant additions of capacity. This contrasts with the back-loaded emission pathway which lowers quantified portfolio cost and risk metrics by delaying resource additions to the end of the decade. Second, an annual

[156] LC 80 Round 1 Comments of RNW at 29-30
[157] LC 80 Round 1 Comments of Staff at 25-26
[158] LC 80 Round 1 Comments of Staff at 27

build limit of 500 MW is placed on the generic capacity and VER resources in portfolio modeling after 2031 to smooth out resource additions and prevent very large resource additions from happening in a single year to meet the large increase in capacity need in 2040.[159]

Tightening the annual build limit on the generic resources would not change the overall quantity of resources needed but would result in a resource buildout that is shifted forward in time and spread out across more years. The change in timing of resource additions would produce two competing effects on portfolio risk. It would reduce unquantified procurement and non-compliance risk by increasing the buffer between when resources are added and when they are needed for compliance but would also increase quantified portfolio cost and cost-risk due to declining cost curves and discounting. PGE will seek to balance the tradeoffs between these multiple sources of risk in our procurement strategy between now and 2040.

6.2.4 Offshore wind in Preferred Portfolio

RNW and Deep Blue Pacific Wind suggest that the Preferred Portfolio should include offshore wind because offshore wind is part of the least-cost and least-risk portfolio.[160] [161] RNW presents results from a supplemental offshore wind report PGE conducted at the request of the Oregon Department of Energy (ODOE) and Staff as evidence that offshore wind is a least-cost resource that should be included in the Preferred Portfolio. RNW claims that the IRP does not test the economic value of offshore wind because it was not evaluated under appropriate and comparable conditions because the offshore wind portfolio in the IRP cannot be compared to portfolios containing transmission expansion.[162] RNW also presents results from alternative portfolio analysis which they conducted that makes offshore wind available in the Preferred Portfolio and shows it offsetting other resources, claiming that it makes a more interesting and relevant comparison.[163] RNW recommends that PGE include at least 1 GW of offshore wind in the Preferred Portfolio.[164]

PGE's response

PGE agrees that offshore wind represents an attractive potential resource to meet our needs if it becomes available for acquisition. This is highlighted in the results of our supplemental offshore wind report, which shows the usefulness of up to approximately 2.8 GW of offshore wind additions. Results of the Preferred Portfolio from PGE's Addendum to the 2023 CEP/IRP

[159] The 500 MW annual limit does not have a binding effect on resource additions until 2036 for generic VER and 2038 for generic capacity.
[160] LC 80 Round 1 Comments of RNW at 37-38
[161] LC 80 Round 1 Comments of Deep Blue Pacific Wind at 10-11
[162] LC 80 Round 1 Comments of RNW at 34-35
[163] LC 80 Round 1 Comments of RNW at 38-39
[164] LC 80 Round 1 Comments of RNW at 32

also demonstrate the large potential role for offshore wind using generic resources, with over 5.7 GW of generic VER resources added through 2043, some or all of which could be filled by offshore wind. However, there are real concerns that this total quantity would realistically all be delivered to PGE alone.

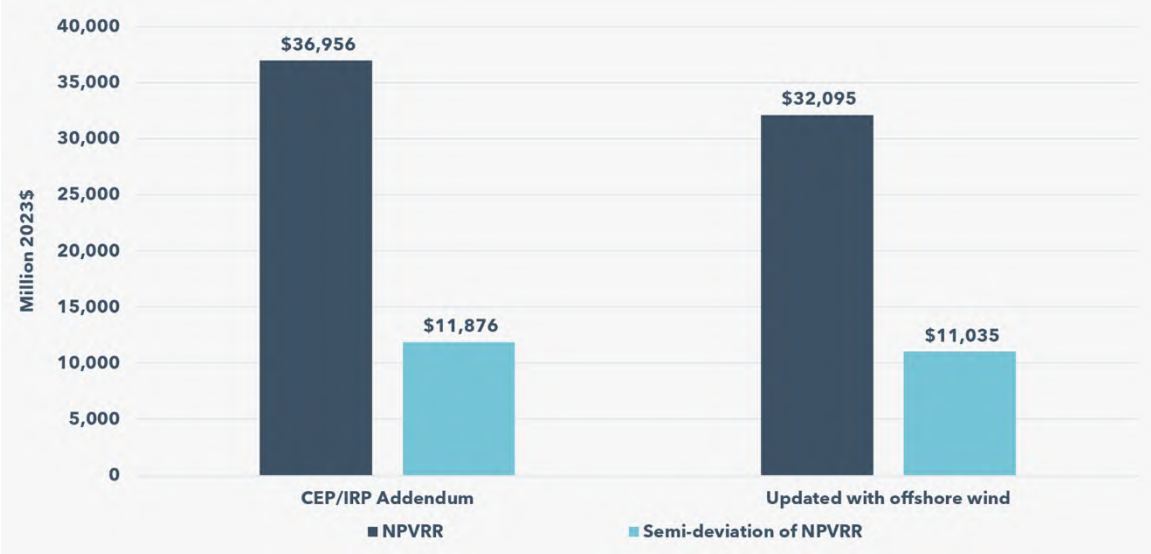
While PGE disagrees with RNW's suggestions that the results from either their own analysis or PGE's supplemental offshore wind study should determine the composition of the Preferred Portfolio, we understand that making offshore wind available in the Preferred Portfolio may offer increased clarity on the fact that PGE views it as a valuable potential resource to help meet our forecasted large resource needs, if it becomes available.[165] Consistent with RNW's recommendation, PGE has conducted new analysis and updated the Preferred Portfolio to include access to 1000 MW of offshore wind beginning in 2032.[166] Results from the new Preferred Portfolio show that all 1000 MW of available offshore wind are added by 2037 (**Table 7**). The most notable impact to the resource additions of the Preferred Portfolio is a reduction in reliance on generic resources. The total amount of generic VER added through 2043 decreases from 5756 MW to 4326 MW, with the total amount of generic capacity decreasing from 2043 MW to 1818 MW. While the full 800 MW of transmission expansion is still added in the portfolio, the timing changed, with the addition of some NV Solar and transmission expansion being delayed. As a result, the total amount of transmission expansion added through 2030 decreases by 74 MW to 726 MW.

Figure 8 shows the difference in portfolio cost and risk metrics between the Preferred Portfolio from the filed Addendum and the new Preferred Portfolio, which includes 1000 MW of offshore wind. The offsetting of a substantial amount of generic resources with offshore wind resulted in a decrease in portfolio NPVRR of approximately $4.86 billion.

[165] PGE's modeling approach is not predicated upon the comparison of the Preferred Portfolio against other portfolios, as described in **Section 6.3, Preferred Portfolio**.

[166] The updated analysis also includes the correction of a minor error present in portfolio analysis in the Addendum to the CEP/IRP. While in the filed Addendum PGE describes an update to the energy accounting methodology to start accounting for the 7 MWa of negative energy associated with battery storage in PGE's portfolio, the associated impact was omitted from the energy need value used in portfolio analysis. The effect was that resources of the Preferred Portfolio in the Addendum were based on a slightly smaller energy than they should have been.

Figure 8. Cost and risk metrics of the Preferred Portfolio



The cumulative resource additions from 2024-2030 in the updated Preferred Portfolio are shown in **Table 5** (offshore wind is not visible in this table because it is not available until 2032).

Table 5. Cumulative resource buildout in Preferred Portfolio

	2024	2025	2026	2027	2028	2029	2030
Wind	0	0	708	1108	1128	1528	1528
Solar	0	0	0	0	0	176	326
Hybrid	0	0	298	298	890	1010	1010
Battery Storage	0	0	0	0	0	0	0
Pumped Hydro Storage	0	0	0	0	0	0	0
Offshore Wind	0	0	0	0	0	0	0
CBREs	0	0	66	85	110	133	155
WY Tx	0	0	0	0	0	400	400
NV Tx	0	0	0	0	0	176	326
Generic VER	0	0	0	0	0	0	331
SoA Tx	0	0	0	400	400	400	400
Additional EE & DERs	0	0	0	0	0	0	0
Non-GHG-Emitting Contract Extension	0	0	200	200	200	200	200
Cost-effective EE (MWa)*	30	60	90	120	150	183	216
Cost-effective DR*	133	162	183	199	211	218	228

	2024	2025	2026	2027	2028	2029	2030
Clearwater Wind **	311	311	311	311	311	311	311
Seaside Storage **	0	0	200	200	200	200	200
Troutdale Storage **	0	200	200	200	200	200	200
Evergreen Storage **	0	75	75	75	75	75	75

* Contributions reduce need

** 2021 RFP resources

Table 6 provides an update of Table 2 from the filed CEP/IRP, providing a summary of total resource actions from 2023 through 2030, showing incremental new resources added by year (it does not show resource losses). It includes the IRP Preferred Portfolio resources and non-CEP/IRP resource actions (2021 RFP resources, qualifying facility resource additions, GFI solar additions, etc.).[167] **Table 6** also includes PGE's retail load service GHG emissions glidepath from 2023 through 2030.

Table 6. Preferred Portfolio resource pathway through 2030 (incremental additions)

Values in nameplate MW	2023	2024	2025	2026	2027	2028	2029	2030
DR (cost-effective)	24	26	25	19	14	11	8	9
EE (cost-effective)	31	30	30	30	30	31	33	33
Storage	0	0	275	200	0	0	0	0
Solar & wind	30	734	69	718	410	30	586	491
Offshore wind	0	0	0	0	0	0	0	0
Hybrid	0	0	0	298	0	592	120	0
CBRE	0	0	0	66	19	25	23	22
Transmission (Tx) market access	0	0	0	0	0	0	576	150
Contract extension	0	0	0	200	0	0	0	0
GHG glidepath (MMTCO2e)	5.9	5.3	5.0	4.4	3.7	3.0	2.3	1.6

Table 7 shows incremental resource actions from year 2031 through 2043. It also includes PGE's retail load service GHG emissions glidepath from 2031 through 2043.

Table 7. Preferred Portfolio resource pathway 2031-2043 (incremental additions)

Values in nameplate MW	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
DR (cost effective)	11	8	9	8	5	11	7	7	7	1	6	11	3

[167] As a result of including non-CEP/IRP and non-RFP resources the values in this table will differ from those in **Table 6**. For simplification purposes, generic VER resources and 5 MW of qualifying facility biomass are included in the wind & solar values.

Values in nameplate MW	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
EE (cost effective)	34	34	32	31	29	28	25	23	19	16	15	11	9
Storage	0	0	100	100	100	100	100	100	100	2100	0	0	0
Solar & wind	522	0	0	0	7	500	500	500	500	574	483	258	225
Offshore wind	0	237	235	253	252	0	23	0	0	0	0	0	0
Hybrid	0	0	0	0	0	0	0	0	0	0	0	0	0
CBRE	0	0	0	0	0	0	0	0	0	0	0	0	0
Tx market access	0	0	0	0	0	0	0	0	0	74	0	0	0
Capacity	0	0	0	0	27	119	172	500	500	500	0	0	0
GHG glidepath (MMT CO2e)	1.5	1.3	1.1	1.0	0.8	0.6	0.5	0.3	0.2	0.0	0.0	0.0	0.0

6.2.5 Clarity on post-2030 resources

RNW suggests that the Preferred Portfolio should contain specific resources rather than generic resources.[168] They present an alternative Preferred Portfolio developed using their own assumptions that reduces the reliance on generic resources by allowing the model unconstrained access to offshore wind and WY and NV transmission expansion resources. RNW presents results showing that using these assumptions produces lower portfolio costs than those associated with PGE's Preferred Portfolio from the filed CEP/IRP Addendum.[169] RNW suggests that this provides clarity on post-2030 resources and sends better market signals to developers.[170]

PGE's response

PGE agrees that a plan with more clarity on the mix of post-2030 resources would send a better market signal to developers and as noted in **Section 6.2.4, Offshore wind**, we have amended the Preferred Portfolio to include access to 1000 MW of offshore wind beginning in 2032. We disagree however, that all resources in the portfolio need to be specific to be informative. PGE does not have the ability to predict the full set of resources that will be available throughout the planning horizon, and this reality is the driver behind a key modeling paradigm used in portfolio analysis; there are no specific resources modeled in the IRP. All resources in IRP portfolio modeling are proxies, including the generic resources. Generic resources are just proxies defined with less-specific characteristics than the traditional set of proxy resources. Given the uncertainty about resource availability, proxy

[168] LC 80 Round 1 Comments of RNW at 41
[169] LC 80 Round 1 Comments of RNW at 32
[170] LC 80 Round 1 Comments of RNW at 40-41

resources provide a reasonable modeling construct to represent the wide range of potential specific resources that may become available and to send market signals at an appropriate level of specificity.

PGE made the modeling choice to rely on generic resources to meet the majority of post-2030 energy and capacity needs because of uncertainty in the availability of emerging resources. There are many potential resource options that may become available to fill the need met by generic resources in the Preferred Portfolio. Just as the use of proxies for resources like onshore wind and solar does not represent a lack of interest in any specific projects that may become available, the use of generic resources does not signal a lack of interest in any specific resource; rather it represents an openness to all variety of resources that may become available without claiming an unfounded level of certainty which resources will emerge as viable options. However, PGE anticipates working with RNW and other stakeholders in future planning cycles to determine the most appropriate method to model potential resources in a way that considers the increased levels of uncertainty in the later years of the planning horizon.

PGE also disagrees with RNW's logic that the lower NPVRR of their portfolio makes it the Preferred Portfolio. The generic resources which are offset in RNW's portfolio were designed to be expensive relative to the proxy resources and it is logical that portfolio costs will decrease when less of the generic resources are added. The Preferred Portfolio was hand designed based on analysis of key questions as well as the imposition of constraints designed to produce a portfolio that accounts for the reality of PGE's system and planning environment. This is illustrated through the fact that PGE analyzed portfolios throughout the course of portfolio analysis that produced lower NPVRR than the Preferred Portfolio, such as one that did not impose any transmission constraints. However, such a portfolio does not represent an outcome that PGE views as realistic or a portfolio that is actionable. Comparison of scoring metrics of all types, including NPVRR, must be made with consideration for the broader analysis approach and judgement used to determine their application in determining the composition of the Preferred Portfolio. Finally, PGE notes that RNW's suggestion of allowing uncapped access to transmission expansion is contrary to the suggestion by Staff that transmission expansion be excluded from the Preferred Portfolio (see **Section 6.3, Preferred Portfolio**).

6.2.6 Conditional firm transmission and ELCCs

RNW suggests that PGE should modify the ELCC analysis to conform to their suggestions for modeling conditional firm transmission.[171]

[171] LC 80 Round 1 Comments of RNW at 51

PGE's response

As described in **Section 2.2, Conditional firm transmission modeling**, PGE disagrees with RNW's recommendation for modification to assumptions about modeling of conditional firm transmission. Accordingly, PGE does not think it is reasonable to conduct portfolio analysis using ELCCs that do not differ between firm and conditional firm resources as their proposed methodology would suggest. Doing so would result in higher ELCCs for conditional firm resources, decreasing the resulting resource build required to meet capacity needs and producing an inadequate portfolio in the face of contractual transmission impacts.

6.2.7 Transmission avoidance

Staff is concerned that the CEP/IRP is undervaluing on-system capacity resources that can reduce transmission congestion.[172] Staff suggests that in PGE's modeling, while on-system resources that provide energy like CBREs and EE allow the avoidance of transmission upgrades, capacity-only resources like storage and DR cannot help avoid transmission upgrades because they do not help to meet GHG targets. Staff asks PGE to adopt, for the next CEP/IRP, a transmission modeling approach that considers the ability of on-system capacity resources, like batteries or DR, to alleviate transmission congestion and thus avoid transmission upgrades and associated costs.

PGE's response

While PGE will continue to improve aspects of our transmission modeling approach, we disagree that portfolio analysis in the CEP/IRP does not account for the ability of on-system capacity to alleviate transmission congestion or capture the value they provide by avoiding transmission costs. There are two reasons that this is the case. First, because off-system renewable resources are added to meet both energy and capacity needs, on-system capacity resources can still help avoid or delay off-system renewable resources if they are being added for their capacity contribution. Second, HB 2021 GHG emissions targets create both energy and capacity needs, as demonstrated by the large increase in capacity need in 2040 when a 100 percent GHG-emissions reduction is required. The large additions of capacity resources in the Preferred Portfolio are driven by HB 2021 GHG targets just as the large additions of renewable resources are. Therefore, in addition to being able to avoid the addition of off-system renewables which provide both energy and capacity, the value of on-system capacity resources is also captured by their ability to offset additions of the generic capacity resource, which represents any number of potential types of resources, including access to capacity resources enabled by new transmission. Because generic capacity was designed to be slightly more expensive that the costliest proxy resource (NV solar and

[172] LC 80 Round 1 Comments of Staff at 35

transmission expansion), the ability to offset additions of generic capacity captures substantial value in portfolio modeling.

6.3 Preferred Portfolio

Staff recommends that PGE re-design and re-evaluate the Preferred Portfolio without assuming up to 800 MW of transmission expansion access. Staff suggests that the availability of these options should be considered as a scenario or sensitivity instead. Staffs suggests PGE should analyze a large set of alternative portfolios that test varying paces of GHG reductions and varying community benefits in a way that can be directly compared to the Preferred Portfolio.[173]

PGE's response

PGE's approach to portfolio analysis was designed to test specific questions about key topics such as GHG emissions trajectories, transmission, CBREs, and DERs. This was done using groups of portfolios, within which portfolios were designed to be compared against one another. As discussed in **Section 6.4, Scoring metrics**, evaluating all potential combinations of portfolios is unfeasible and unnecessary to gain insights about key questions posed in this CEP/IRP. Additionally, PGE notes that the acknowledged 2019 IRP also used a 'hand-designed' approach to creating a Preferred Portfolio and that the comparability of the Preferred Portfolio to other portfolios is neither an IRP guideline nor requirement.

The insights from the evaluation of portfolios within key portfolio groups were used to inform the creation of the Preferred Portfolio. The tradeoffs of varying paces of GHG reduction was explored in detail in the decarbonization portfolio group, with the linear-glidepath found to provide the best balance of rate of emissions reduction with cost and risks. Similarly, analysis within the transmission portfolio group highlighted the large need for both transmission upgrades and expansion to bring needed energy from new renewables, both within and outside of the PNW, to PGE's load. The addition of transmission expansion was also found to reduce portfolio costs. Guided by these insights, PGE decided that transmission expansion was an important component of the Preferred Portfolio and believes it would be inappropriate to exclude it. PGE also notes that the suggestion by Staff to remove the 800 MW of transmission expansion from the Preferred Portfolio runs contrary to the suggestion by RNW (described in **Section 6.2.5, Clarity on post-2030 resources**) that the Preferred Portfolio be allowed access to uncapped amounts of transmission expansion.

However, to explore the impact of Staff's suggested change to the Preferred Portfolio, PGE conducted new analysis for these Reply Comments, modeling the Preferred Portfolio from the Addendum with the 800 MW of transmission expansion removed. This was done to test

[173] LC 80 Round 1 Comments of Staff at 24

the effect of the change requested by Staff only and is for informational purposes only. The resulting portfolio produced a $4.32 billion increase in costs compared to the Addendum Preferred Portfolio (**Figure 9**). The resource buildout through 2030 in the new no transmission expansion portfolio is shown in **Table 8**.[174] Without access to the transmission expansion, the portfolio produced several notable differences in resource buildout. Most notably, the portfolio has increased reliance on both generic capacity and generic VER. Although not shown in **Table 8,** the first year of generic capacity addition shifted forward from 2034 to 2031 and the total amount added increased from 2043 MW to 2716 MW. The first year of addition for generic VER shifted forward one year from 2030 to 2029 and total additions increased from 5756 MW to 6555 MW. Additionally, while the total amount of battery storage added did not change, the first year of addition also shifted forward, from 2032 to 2030. The quantity and timing of additions of pumped hydro did not change.

Figure 9. Cost and risk metrics of the Preferred and no transmission expansion portfolios

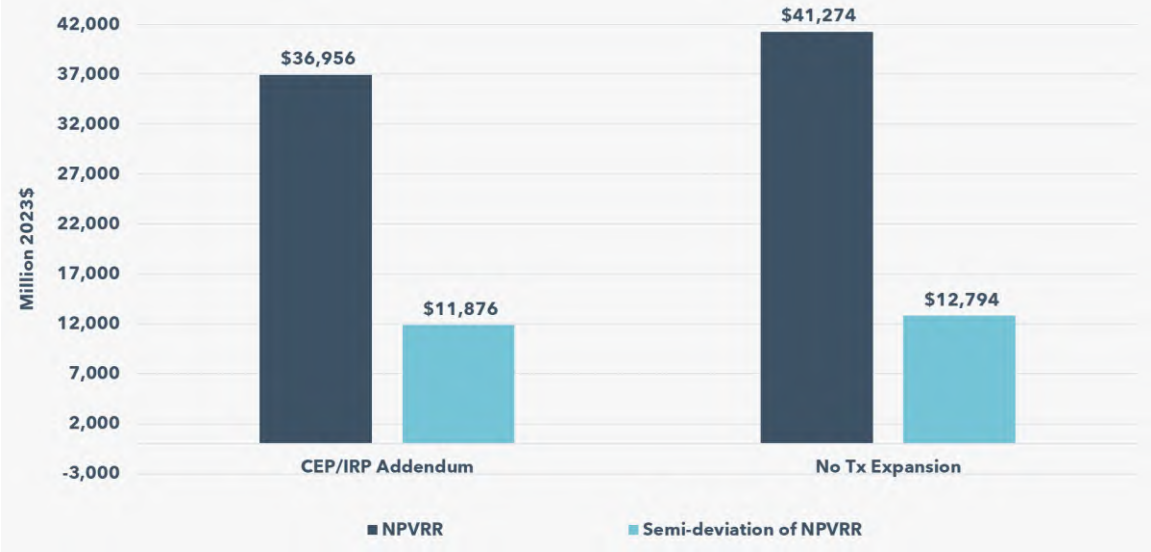


Table 8. Cumulative resource buildout in no transmission expansion portfolio

	2024	2025	2026	2027	2028	2029	2030
Wind	0	0	690	1090	1128	1128	1128
Solar	0	0	0	0	0	0	0
Hybrid	0	0	299	299	873	1010	1010
Battery Storage	0	0	0	0	0	0	341
Pumped Hydro Storage	0	0	0	0	0	0	0
Offshore Wind	0	0	0	0	0	0	0

[174] **Table 8** shows resources added in PGE's capacity expansion model, ROSE-E, only. It does not include the 2021 RPF resources or cost-effect quantities of DERs shown as part of the Preferred Portfolio in **Table 5**.

	2024	2025	2026	2027	2028	2029	2030
CBREs	0	0	66	85	110	133	155
WY Tx	0	0	0	0	0	0	0
NV Tx	0	0	0	0	0	0	0
Generic VER	0	0	0	0	0	594	1064
SoA Tx	0	0	0	400	400	400	400
Additional EE & DERs	0	0	0	0	0	0	0
Non-GHG-Emitting Contract Extension	0	0	200	200	200	200	200

6.4 Scoring metrics

Staff has several recommendations on the topic of portfolio scoring metrics. Staff suggests that PGE should adopt a scoring metric for the pace of GHG reductions to show the tradeoffs between cost, risk, the pace of GHG reductions, and community impacts and benefits across portfolios and suggest PGE consider use of the Social Cost of GHGs to contextualize tradeoffs between portfolios.[175] Staff also suggests that PGE should design a scoring metric for near-term cost impacts that can be applied across all portfolios and justify its use in planning and procurement decisions.[176] Staff suggests that PGE does not use portfolio scoring consistently across all portfolios, resulting in a sub-optimal quantity of EE in the Preferred Portfolio.[177] Finally, Staff recommends that in the future, PGE should justify portfolio analysis findings and design principles used to develop the Preferred Portfolio based on all scoring metrics, not just those that address cost and risk.[178]

PGE's response

PGE believes Staff is being overly prescriptive in this recommendation. There are many ways to design portfolio analysis; while it is up to the Company to justify why results from portfolio analysis are in the long-term interest, it's appropriate to consider portfolio analysis using all applicable methods, not just uniform scoring metrics. For example, as noted above in **Section 6.2.3, Clean capacity glidepath**, PGE used the unquantifiable procurement risk to not favor the back-loaded decarbonization glidepath. PGE notes that using scoring metrics for specific decisions (like near-term costs or GHG reductions) is not required by IRP or CEP guidelines. PGE believes that Staff should not require this specific modeling approach to determine whether the Company's portfolio analysis is appropriate.

[175] LC 80 Round 1 Comments of Staff at 25
[176] LC 80 Round 1 Comments of Staff at 25
[177] LC 80 Round 1 Comments of Staff at 5
[178] LC 80 Round 1 Comments of Staff at 25

While PGE looks forward to working with Staff and stakeholders in the next IRP to refine our portfolio modeling approach, we are confident in the appropriateness of the approach employed in this CEP/IRP, which is designed to focus effort on the most pressing planning questions in the face of a rapidly evolving planning environment that presents many new challenges. The structure of our portfolio analysis allows the evaluation of the trade-offs and implications of GHG emission reductions and to determine an appropriate approach to EE in the Preferred Portfolio.

As mentioned in **Section 6.3, Preferred Portfolio**, PGE's portfolio analysis approach does not rely on evaluating every possible combination of portfolio options. Evaluating scoring metrics across all portfolios is not necessarily useful. For example, evaluating the near-term costs of an offshore wind portfolio against a CBRE portfolio does not provide insightful information to guide the creation of the Preferred Portfolio. Comparing the near-term costs across all portfolios is also not informative because near-term costs are an issue specific to EE and the near-term cost implications of varying levels of EE addition can be compared within the EE portfolio group. There are no other portfolios where the near-term costs implications are different than their long-term cost metrics. Similarly, the pace of GHG reductions only needs to be compared within the decarbonization group of portfolios because that is where those tradeoffs are being analyzed. Further, it is not feasible to compare all combinations; there are seven EE and eleven transmission portfolios, to evaluate all combinations of each would produce 77 portfolios.[179]

Regarding the optimal quantity of EE in the Preferred Portfolio, as noted in **Section 6.2.5, Clarity on post-2030 resources**, the fact that adding a resource to the Preferred Portfolio may lower NPVRR does not necessarily indicate that it must be included to produce an optimal outcome. Multiple criteria, considering both quantifiable and unquantified sources of risk, are considered in the designing the Preferred Portfolio. In the case of EE, the near-term cost impacts associated with EE were deemed too risky to warrant its inclusion in the Preferred Portfolio at this time despite the potential long-term cost benefits.

6.5 Supply-side options

6.5.1 Pumped hydro

Swan Lake and Goldendale suggests that the assumption of a 38-year useful life used in PGE's derivation of pumped hydro cost estimates is too short and requests that Staff direct PGE to re-run portfolio analysis using a 50-year life and evaluate a 75-year sensitivity. Swan

[179] Extending this logic further, adding in the five CBRE, five decarbonization, four optimized, two targeted-policy, and six emerging technology portfolios would create 92,400 portfolios. It is obvious that some judgment is needed to determine which set of portfolio choices are appropriate to model.

Lake and Goldendale suggests that PGE was incorrect in the claim that a 38-year useful plant life assumption was supported by a study conducted by the engineering firm HDR.[180]

PGE's response

The Preferred Portfolio from PGE's Addendum to the CEP/IRP show a need to acquire over 4.8 GW of capacity resources by 2043. This includes 2 GW of pumped hydro storage added in 2040. This represents a very large amount of capacity resources and demonstrates PGE's interest in resources that can help fill this need. As with all resources modeled in the IRP, the pumped hydro storage resource is a proxy resource, designed to represent a range of potential projects that may become available for acquisition. This concept is discussed further in **Sections 6.2.4, Offshore wind** and **6.2.5, Clarity on post-2030 resources**. The unique operational and cost characteristics that distinguish specific projects from one another will be considered in the analysis of actual projects if they submit bids to an RFP.

PGE notes the HDR narrative discussion cited by the Projects. However, the 38-year useful life assumption came from quantitative data provided by HDR in Excel format for input to PGE's models in the 2019 IRP analyses. For these Reply Comments, PGE conducted new analysis to compare the cost differences that result from changing the assumption of useful life from 38 years to 50- and 75-year life. Results show that a change in useful life from 38 years to 50 years results in approximately an 8 percent reduction in the levelized fixed cost and a change to 75 years results in an additional 7 percent reduction. These values assume the same construction costs are incurred upfront, the same annual fixed costs occur annually, and no incremental capital expenditures are required to support a longer useful life.

To test the robustness of portfolio analysis results to changes in the cost assumptions of pumped hydro storage, PGE conducted additional new analysis modeling the Preferred Portfolio from the Addendum using 15 percent lower fixed costs for pumped hydro storage. Testing a decrease in costs consistent with the longest useful life suggested by the Projects, PGE found no impact on resource additions compared to the use of PGE's cost assumption. Just as when using PGE's cost assumption, derived using a 38-year useful life, all 2000 MW of available pumped hydro are added in 2040. The cost test resulted in no change to the resources in the Preferred Portfolio in the Addendum, demonstrating the robustness of portfolio analysis results to the changes in plant life assumptions suggested by the Projects. Therefore, PGE does not believe that re-running all of portfolio analysis with alternative plant life assumptions for pumped hydro would be informative.

[180] LC 80 Round 1 Comments of Swan Lake and Goldendale at 2-4

6.5.2 Offshore wind

RNW disputes PGE's characterization of offshore wind as an emerging technology.[181] They cite over 200 MW of floating offshore wind in operation globally today and projections for large increases by 2027. RNW also claims that the costs included in the IRP for commercial operation dates after 2030 PGE are conservatively high, suggesting that PGE appears to not be fully accounting for all the factors considered by NREL, such as either the geographic specificity of southern Oregon or the changes in cost over time.[182]

PGE's response

PGE stands by its characterization of offshore wind. While it offers attractive characteristics, there are currently no offshore wind facilities in Oregon and much remains to be developed before the offshore wind can be assumed to be available to provide energy for PGE's customers. The transmission requirements noted in **Section 2.1, Comprehensive transmission comments** describe several challenges in both transmission and interconnection that need to be addressed before PGE can procure energy from an offshore generator. This characterization does not change that fact that, as described in **Section 6.2.4, Offshore wind**, PGE has a large resource need and represents a very interested potential buyer of the resource if it becomes available and has updated the Preferred Portfolio to include 1000 MW of offshore wind.

Given the lack of existing offshore wind in Oregon, the estimates of costs are naturally uncertain. A number of factors can explain the majority of difference between PGE's and NREL's LCOEs:

- PGE costs are presented for 2030 COD while NREL's costs are provided for a 2032 COD. Costs for a later COD are expected to be lower than an earlier COD. A lower overnight capital cost will result in a lower LCOE, all else equal.
- PGE's LCOE is reported in 2023 dollars while NREL's report provides values in 2019 dollars. Adjusting for four years of inflation results in relatively higher costs.
- PGE's resource costs use the projected utility cost of capital (including capital structure, costs of equity and debt, and tax rates). NREL uses a capital structure more heavily weighted towards debt financing, resulting in a lower cost of capital and lower cost of ownership.
- PGE's modeling resulted in an approximately 55 percent capacity factor for the Southern Oregon offshore wind site; this compares to the 57 percent stated in the

[181] LC 80 Round 1 Comments of RNW at 40
[182] LC 80 Round 1 Comments of RNW at 39

NREL report. A relatively higher capacity factor results in more assumed energy generation and a lower LCOE (where annual energy generation is the denominator).

- In total, these adjustments result in an approximately $3/MWh (5 percent) difference remaining between PGE and NREL.

Chapter 7. Request for proposals

7.1 CBREs

PGE received comments regarding CBRE acquisition strategy from Staff and Energy Advocates. On this topic, Staff poses several questions.[183] First, Staff asks if PGE plans to pursue CBRE technologies beyond the proxy resource types included in the CBRE potential study. Second, Staff asks what PGE's strategy is to balance CBRE acquisition costs while maximizing community benefits; specifically considering strategy to leverage funding resources and other partnerships, and key emerging risks and decision points. Third, Staff asks what steps PGE can take to overcome implementation risks and ensure that company resources associated with CBRE procurement activities are used effectively. Energy Advocates suggests that PGE's CBRE actions should go beyond an RFP to include additional approaches to acquire CBREs that are unlikely to bid into an RFP due to the resources required to submit a bid.[184]

PGE's response

PGE anticipates pursuing CBRE technologies beyond the proxies modeled in the IRP. The proxy resources were designed based on their existence on the grid today, meaning that we could better estimate cost and availability for the purpose of forecasting CBRE. The technologies available in the market include distributed solar paired with storage, but PGE is open to any technology type provided it complies with the CBRE definition in HB 2021 and provides value to the grid.

PGE anticipates that an RFP structure for CBRE resources would only begin the process to meet the targets identified in the CEP/IRP. If the market response to an RFP is sufficient in both volume and benefit, PGE may pursue those projects. If an RFP is unable to provide the volume and benefit expected, PGE will continue to move forward complementary processes to identify resources that may otherwise not choose to bid into an RFP-like structure. Because there are substantial unknowns about the potential costs, we will use the RFP process to learn

[183] LC 80 Round 1 Comments of Staff at 20-21
[184] LC 80 Round 1 Comments of Energy Advocates at 15

and iterate. PGE plans to leverage other funding; federal, state, and local dollars are being directed to support this kind of projects.

PGE believes that maximizing community benefits is important but is also subjective at this point and we are working to make sure our approach aligns with the CBI work to date and continued conversations with stakeholders via CBIAG, learning lab and other advisory groups. We look forward to working with Staff and stakeholders in the coming months to share a set of minimum criteria that will identify how projects can demonstrate grid value. CBRE acquisition represents a clear opportunity to both take action that affects EJ communities and leverages PGE's current capabilities. Additionally, as we continue to develop capabilities around outreach, engagement, and quantification of CBIs, we will explore EJ-specific actions in future CEP/IRP filings.

7.2 Procurement levels

In related comments regarding PGE's procurement strategy Staff recommends that PGE provide additional detail on proposed RFP framework and describe how PGE will respond if an RFP does not result in its targeted procurement level. Staff is specifically interested in detail about PGE's methodology to update the needs assessment, potential offramps, and the process for determining when to close one round of procurement and begin another. Staff also asks how procurement activities will inform other resource actions. Staff suggests that PGE provide regular updates to LC 80 participants on target procurement volume for the 2023 RFP as new information and analysis become available.[185]

PGE's response

PGE filed a planning and procurement forecast in Docket No. UM 2274 on July 17, 2023. PGE's proposed framework includes proposed methodologies for how needs identified in the planning environment should be acted upon, as well as the pace and cadence of future resource acquisition.[186]

PGE's intent with proposing additional bid windows is to alleviate the pressure that would accompany an RFP that is unable to deliver sufficient energy and capacity within the Action Plan window. The ability to re-issue a call for bids under a previously approved structure to recover from a lackluster response would serve as a significant benefit.

Over time, if a lack of market depth was persistent and PGE's ability to procure resources sufficient to maintain continual progress to decarbonize, those results could feed into future

[185] LC 80 Round 1 Comments of Staff at 39-40
[186] See PGE's Planning and Procurement forecast posted to UM 2274 at: https://edocs.puc.state.or.us/efdocs/HAD/um2274had162126.pdf

planning processes in the form of greater reliance on demand-side resources or more specific actions toward non-RFP procurement.

7.3 Scoring

Energy Advocates suggests that the scoring criteria for RFPs should include CBIs or other non-price factors to maximize benefits for environmental justice communities.[187]

PGE's response

PGE acknowledges Energy Advocates' recommendation and their recognition that PGE has proposed community benefits criteria as RFP scoring criteria in the past. PGE looks forward to continued collaboration with stakeholders in future RFPs to determine which scoring criteria provide the least-cost, least-risk outcomes for customers given the resource mix and grid need at the time.

7.4 Timing

7.4.1 Portfolio analysis results

Staff asks if the RFP pacing and supply chain analysis provide quantitative insights into resource acquisition pacing options and whether PGE plans to constrain annual RFPs to match the annual RFP scenario energy and capacity additions.[188]

PGE's response

Results from the RFP size and pacing and supply chain analyses provide insights into the costs and risks of alternative procurement cadences but do not contain exact quantitative recommendations for annual procurement quantities. As described in **Section 7.2, Procurement levels**, PGE's filed planning and procurement forecast in Docket No. UM 2274 provides PGE's proposed framework for the pace and cadence of future resource acquisition. The RFP size and pacing sensitivity illustrates that ability for annual procurement to decrease portfolio costs by more precisely matching the timing of resource additions to needs compared to less frequent acquisitions that add resources in advance of need. The supply chain sensitivity meanwhile demonstrates the potential for supply chain disruptions to increase the cost and risk of resource procurement and highlights the tradeoff between cost risk and compliance risk. While delayed resource acquisition can reduce costs due to

[187] LC 80 Round 1 Comments of Energy Advocates at 15-16
[188] LC 80 Round 1 Comments of Staff at 37-39

discounting and declining resource cost forecasts, it increases the risk of not being able to acquire the resources necessary to comply with GHG emissions reduction requirements.

7.5 Long-lead time RFP

RNW and Deep Blue Pacific Wind suggest that PGE conduct an RFP for long lead-time resources in order to send market signals and provide certainty that will encourage development of offshore wind and other long lead-time resources.[189,190]

PGE's response

PGE does not plan to issue a dedicated long lead-time RFP, but notes that the currently proposed 2023 RFP will seek resources with lead times out through 2029. In addition, we anticipate issuing a request for information (RFI), as noted in the Company's May 19, 2023 filing in UM 2274, to better understand technologies, timing, and future development zones for resources that could contribute toward the company's decarbonization trajectory.[191] This RFI will seek to identify resources that could come online later this decade and in the 2030s and will use responses to prepare for future acquisition cycles (both from a market signal perspective and in terms of preparing the grid for new technologies and locations). Additional information on the RFI process will be available later this year.

Chapter 8. Regulatory

8.1 Small-scale renewables requirement

Staff requests PGE provide a more detailed compliance strategy for the small-scale renewables (SSR) requirement, inclusive of PGE's current and forecasted SSR amounts broken down by resource type and strategies to address potential shortfalls, control costs and promote community benefits.[192]

PGE's response

Section 7.2.6 of the CEP/IRP describes PGE's approach to compliance with the small-scale renewables requirement, highlighting the following activity areas: continued engagement with communities to support project development, project development through existing programs including PURPA and CSP, and deployment of new initiatives including new

[189] LC 80 Round 1 Comments of RNW at 43-47
[190] LC 80 Round 1 Comments of Deep Blue Pacific Wind at 8-9
[191] Available at: https://edocs.puc.state.or.us/efdocs/HAQ/um2274haq15385.pdf
[192] LC 80 Round 1 Comments of OPUC Staff at 21

acquisition actions for CBRE and integration of customer resources into the VPP. PGE shares Staff's interest in a SSR compliance approach that controls costs and drives community benefits, and the alignment of CBRE acquisition with SSR compliance reflects that objective.

In response to Staff's interest in PGE's current and projected SSR compliance position, PGE has extracted and summarized CEP/IRP modeling inputs with relevance to SSR compliance, displayed below in **Table 9**. Further context regarding these forecasts can be found in the respective sections of the CEP/IRP and Addendum.

Table 9. Small-Scale Renewables Forecast

Resource Type	Current Capacity per 2023 CEP/IRP	2030 Forecast as updated in CEP/IRP Addendum
Community Solar Program	27 MW	93 MW
PURPA QF < 20 MW	271 MW	281 MW
CBRE	0 MW	155 MW
Customer DERs (AdopDER forecast)	183 MW (not SSR-eligible per Order 21-464)	739 MW of solar 121 MW of storage[193]
TOTAL SSR ELIGIBLE CAPACITY	**298 MW**	**529 - 1,268 MW**

PGE will continue to assess progress and consider potential additional actions as part of the next CEP/IRP cycle. In response to Staff's question regarding "critical dependencies," we note that success is contingent on implementation of the CEP/IRP Action Plan and related regulatory and policy factors, specifically successful acquisition of CBREs and progress in integrating customer-sited resources into our virtual power plant. Increased ability to manage customer solar as a capacity resource in planning and operations will be a key development toward SSR eligibility of some or all customer DERs. This evolution will be enabled by increased DER visibility and control as well as orchestration of solar with storage and load flexibility to provide system and local capacity benefits, which necessitates advancement of PGE's VPP.

8.2 Avoided cost information

In similar comments, both NewSun and OSSIA noted that their interpretation of OAR 860-029-0080(3) requires PGE to provide draft Avoided Costs in the same format as the final form which is required to be submitted within 30 days of the Commission's acknowledge decision.[194,195]

[193] Some or all solar and storage capacity may be actively included in capacity portfolio via VPP and could be SSR eligible
[194] LC 80 Round 1 Comments of NewSun at 13
[195] LC 80 Round 1 Comments of OSSIA at 2

PGE's response

PGE has provided all the elements of the avoided costs within the CEP/IRP consistent with previously acknowledged IRPs and thus, PGE believes it has complied with the intent of OAR 860-029-0080(3). As part of PGE's Round 0 comments, PGE provided details on the different components of the avoided costs.[196]

8.3 RECs

Staff expresses a desire to understand how PGE might realize value from an expected increase in the size of the REC bank through time as the number of RECs produced annually exceed the amount needed for RPS compliance. They note that Commission Order No. 22-446 requests that PGE include information about REC generation and plans for their use. Staff recommends that PGE provide the volume of banked RECs that it anticipates will expire if they are not used over the planning horizon and discuss how it can plan to utilize its banked RECs to benefit customers.[197] Finally, the Green Energy Institute provides recommendations for how PGE can communicate facts to retail customers regarding energy and its GHG content.[198]

PGE's response

The forecasted need to add renewable resources to comply with HB 2021 emissions reductions targets is larger than the forecasted need to meet RPS obligations, which means that the amount of RECs generated is forecast to be larger than the amount needed to comply with RPS obligations. IRP modeling does not explicitly forecast the quantities of RECs that are expected to expire. Instead, IRP modeling incorporates a RPS obligation constraint and forecasted REC generation to ensure that the Preferred Portfolio is compliant with RPS obligations. While IRP modeling is not currently designed to produce the requested detail about the timing of REC retirement vs expiration, a comparison of the RECs forecasted to be generated with the RPS obligation can provide some insight. Using data from the updated Preferred Portfolio (presented in **Section 6.2.4, Offshore wind in Preferred Portfolio**), the total number of RECs generated through the planning horizon are compared against the amount required to be retired to meet RPS obligations. The total number of RECs needed to meet RPS obligations over the 20-year planning horizon is 162,440,558 MWh.[199] The total number of RECs generated over the planning horizon, plus existing banked RECs, is forecasted to be 425,686,387 MWh, not including those expected to be retired for voluntary customer sales. That means that PGE is forecasted to produce an excess of 263,245,829

[196] LC 80 PGE's response to Initial Comments at 60
[197] LC 80 Round 1 Comments of Staff at 22-23
[198] LC 80 Round 1 Comments of GEI at 1
[199] Assuming a 20% reduction in the size of the obligation to account for an assumed use of 20% Unbundled RECs.

MWh of RECs through the planning horizon. RECs generated may either be used for current period compliance, banked for use in future compliance periods, or sold. Additional detail about PGE's REC strategy can be found in PGE's 2022 Renewable Portfolio Standard Implementation Plan (RPIP), filed on December 30, 2021.[200] PGE's next RPIP is due to be filed at the end of 2023. Finally, PGE agrees with GEI that full transparency is needed when communicating statements about its emissions accounting and forecasting, especially with the Company's use of RECs.

Chapter 9. Engagement

9.1 Outreach and engagement

On the topic of engagement, parties asked for more details regarding PGE's plans to connect specifically with community members to offer information on how CEP and IRP projects and programs affect individual customers' lives. One suggestion is to use meeting spaces that are after hours and/or in local communities. Similar to recommendations that were received related to accessibility, parties suggested that PGE should work with the UCBIAG to refine and improve its approach to effectively engaging underserved and EJ communities.

PGE's response

In DSP Part 1 in2021, PGE articulated our vision for leading the clean energy future through collaboration, outreach and engagement with our customers and communities.[201] Our commitment to community engagement and collaboration continues to deepen and evolve as we expand that commitment to other areas of resource planning, including our CEP/IRP. We prioritize cultivating relationships with new and existing communities, especially those from or who represent environmental justice communities. Our community engagement is based on the principle of involving those impacted by decisions, and our guiding principle is "nothing about us without us." We believe that a clean energy future requires a commitment to diversity, equity, and inclusion (DEI) throughout our operations.

One example of PGE's evolving approach to community engagement is the creation of a new Community Engagement team reporting into the Public Affairs organization. This new team will be led by a new senior leadership position – Director of Community Engagement – who will be charged with developing and maintaining a comprehensive community engagement program for PGE with the numerous diverse communities we serve. The new Community

[200] Available at: https://edocs.puc.state.or.us/efdocs/HAA/um2216haa162836.pdf
[201] DSP Part 1, available at: https://assets.ctfassets.net/416ywc1laqmd/i9dxBweWPkS2CtZQ2lSVg/b9472bf8bdab44cc95bbb39938200859/DSP_2021_Report_Full.pdf

Engagement team operating under this director will focus on crafting and implementing strategies that support both PGE's business and the goals and aspirations of communities we serve, particularly those representing underserved or underrepresented populations.

The Community Benefits Impacts and Advisory Group will be facilitated by a new manager of Community Engagement, a member of the new Community Engagement team.[202] We recently launched the inaugural CBIAG with a kickoff meeting in April 2023. PGE has hosted four additional meetings since the kickoff. There are currently 13 members that represent and/or serve environmental justice communities and other underserved groups serving on the CBIAG. There are two open seats remaining that are being held to allow time to identify and work with existing members to close representation gaps. This group will advise PGE on many topics, including the CEP/IRP and we plan to leverage their feedback to guide our engagement activities.

9.2 Tribal engagement

On the topic of tribal engagement, RNW and the Energy Advocates advise PGE to engage tribes in conversations relevant to CEP goals and actions. Both parties request more details on PGE's plan, such as, how the plan will "build awareness, inform and provide learning opportunities to communities" and "increase community participation, including Tribal and EJ communities?" and emphasize the importance of having a tribal representative on the UCBIAG. CRITFC echoes the request for meaningful engagement and offers the recommendations in their '2022 Energy Vision for the Columbia River Basin' as a guide for consideration in the energy transition.[203]

PGE's response

PGE appreciates the importance of meaningful Tribal engagement. We recently hired a Tribal Liaison and our team will be working closely with this person to develop a plan for engaging with Tribes and Indigenous communities that builds on PGE's Strategic Tribal Engagement Plan (STEP).[204] Also, we are actively recruiting for a Tribal representative on the CBIAG.

9.3 Accessibility

On the topic of accessibility, several parties reemphasized the need to improve accessibility of the CEP. The CEP needs to communicate PGE's compliance strategy in a manner that is accessible and meaningful to the communities it serves, particularly those that might be

[202] For additional information about CBIAG meetings or materials, please refer to the newly launched webpage: https://portlandgeneral.com/about/who-we-are/community/community-benefits-and-impacts-advisory-group
[203] https://critfc.org/wp-content/uploads/2022/09/CRITFC-Energy-Vision-Full-Report.pdf
[204] PGE's STEP is available in **Appendix B: Strategic Tribal Engagement Plan**

affected by future CBRE projects and resource procurement; communicate in terms relevant to their daily lives. Parties recommended that PGE consult with the UCBIAG on tactics to improve accessibility, including publication in multiple languages.

PGE's response

Staff and stakeholders have been consistent and clear in their pursuit of a more accessible CEP/IRP document and process. PGE took steps to achieve the desired level of accessibility and made adjustments during the proceeding to incorporate feedback and improve the process. Some of these steps and adjustments are described below. We are committed to continuing our efforts to deliver materials and events that are accessible and meaningful to the customers and communities we serve. PGE believes it is important to take a step back and work with Staff, stakeholders and our newly formed CBIAG to develop a standard for what "accessibility" means and what actions should be taken to achieve that standard.

During the CEP/IRP process, we made efforts to improve how we share information and provide more materials. For example:

- We created a dedicated webpage for our CEP and IRP;
- We dedicated the first chapter of the combined CEP/IRP to our decarbonization strategies and path to compliance. This was intended to relieve the reader of having to read through the entire length and complexity of the IRP analysis and chapters that support PGE's decarbonization pathway;
- All past materials and recordings from Learning Labs were available on our webpage so users could access at their convenience;
- Based on feedback we heard from our Learning Lab participants, we switched from using Microsoft Teams to host meetings using Zoom. Zoom was helpful in meeting accessibility needs, because it offered live transcripts and closed captions;
- We are working with Staff and stakeholders to design a community meeting that is more accessible – in community members space at a time that does not conflict with daytime obligations;
- We engaged attendees through various methods, including verbal discussions, chat, Mural Board, Q&A sessions, and real-time feedback; and
- We set up a specific mailbox for community inquiries.

For our IRP we improved our webpage to make information more accessible, including publishing IRP data, roundtable materials, Q&A responses, and video recordings. Our indexing system has been updated based on participant input for easier navigation and we committed to adapting our practices to support standardized information reporting for the CEP in the future.

We deeply appreciate the level of participation and interest from stakeholders in this process. It is important that we make the best use of everyone's scarce time and availability. PGE believes that establishing a clearer standard for accessibility will help achieve our shared objectives.

9.4 Feedback

On the topic of feedback, parties reiterated that PGE should more clearly record and communicate what feedback and recommendations were received across all engagement venues, whether that feedback was incorporated into the CEP/IRP, and why. The process for gathering input from communities on the CBIs was a particular point of interest, i.e., understanding who was consulted and how that feedback was used.

PGE's response

In Section 1.3 of PGE's response to the Round 0 comments, we provided a description of how feedback was captured and incorporated throughout the process to develop the CEP/IRP.[205] PGE understands and appreciates the effort required for stakeholders, especially uncompensated EJ stakeholders, to participate in the CEP/IRP proceedings. It is important that we make the best use of everyone's time and availability. PGE believes that establishing a clearer standard for the treatment of feedback will help achieve our shared accessibility objectives. It is necessary at this point to step back and work with Staff, stakeholders and the CBIAG to establish a standard for appropriate, meaningful treatment of feedback.

9.5 Tax incentives and funding opportunities

Stakeholders appreciate that PGE gave descriptions of the federal incentives available to the utility and has considered these cost saving opportunities as PGE makes investments to meet emissions targets. They also are encouraged by our discussion of the Justice40 initiative which requires that certain federal investments result in 40 percent of the benefits flowing to disadvantaged communities.[206] These include investments areas of clean energy and energy efficiency; clean transit; affordable and sustainable housing; training and workforce development; the remediation and reduction of legacy pollution; and the development of critical clean water infrastructure.

Given the critical role that these incentives play in supporting attainment of HB 2021's emissions targets, stakeholders request that the Company file updates on its planning for use of these funds and include analyses of how it expects the 40 percent of benefits will flow to

[205] PGE's response to Round 0 Comments: https://edocs.puc.state.or.us/efdocs/HAC/lc80hac102443.pdf
[206] https://www.whitehouse.gov/environmentaljustice/justice40/

disadvantaged communities. Stakeholders would like to be timely informed of the analyses and strategies PGE employs to maximize the value of federal incentives and how those strategy options meet or exceed the Justice40 benefits goal for disadvantaged communities.

PGE's response

PGE appreciates the feedback from CUB on the federal funding opportunities the company is pursuing. PGE shares the concerns of the US DOE around the need for workforce development to support the clean energy transition and has been pursuing multiple paths with other stakeholders to ensure the needed workforce is available in Oregon.

Recognizing the need for a collective effort to build an equitable and inclusive workforce that is adaptable to meet the needs of today and in the future, PGE convened the Oregon Clean Energy Workforce Coalition in 2022. The OCEWC is comprised of nearly 60 different organizations from around the state including other electric utilities, education providers, state agencies, union labor, municipalities, community-based organizations, nonprofits, local workforce investment boards, and other related stakeholders. The OCEWC has created and adopted a strategic plan with a priority of focusing on those occupations most in need to support the transition now including jobs in energy efficiency, construction, and energy infrastructure. The Coalition has pursued two separate grants this year to support the work. If successful, some of the funds would be used to pursue a market study that would evaluate the workforce needs in the clean energy sector, including additional policy drivers at the state and federal level that will increase workforce needs in the state.

All of PGE's infrastructure related grant applications include strong labor standards to attract and retain a workforce to build the proposed projects as well as coordination with the OCEWC. PGE recognizes the importance of not only supporting an equitable and inclusive clean energy workforce, but also ensuring that the implementation of our grants is benefiting those most impacted by the effects of climate change. PGE will provide updates to interested parties on the strategy to accomplish workforce and Justice40 goals as grants are awarded and implemented.

Appendix A: Comment and Response Crosswalk

This appendix catalogues stakeholders' comments as identified by PGE and provides a reference to the chapter and section number in which PGE responded to the comment. In many cases, the comment is only represented by a few words so that it can be searched for and found in the original comment document.

Comment Source	Comment	Sec #	Section
AWEC	PGE's proposed no-regret transmission actions are the result of unrealistic model constraints rather than economic analysis.	2.1	Comprehensive transmission response
AWEC	PGE's transmission Action Items are not actionable, in part evidenced since they did not change between the filed CEP/IRP and the Addendum.	2.1	Comprehensive transmission response
AWEC	PGE's CEP/IRP market price forecast is unreliable and not consistent with planned resource additions or planned sales of GHG emitting energy, leading to unreliable portfolios and portfolio costs.	4.1	Price forecasting
AWEC	The ELCC estimates do not take the impact of similar resources into account, which may lead to incorrect values and a deficit portfolio.	4.2	ELCC values
AWEC	Due to the Preferred Portfolio not being tested in an hourly adequacy model it may not meet reliability standards.	4.3	Resource adequacy
AWEC	PGE created an arbitrary benefit for CBREs to justify their acquisition beyond the small-scale renewables requirement in ORS 469A.210 and should also examine biomass resources to satisfy this mandate.	5.4	CBRE acquisition
CRITFC	PGE should take into consideration and implement where applicable our 2022 Energy Vision for the Columbia River Basin.	9.2	Tribal engagement
CRITFC	CRITFC recommends that PGE develop a process to meaningfully engage tribes/tribal communities during the development of its CEP and beyond.	9.2	Tribal engagement
CRITFC	PGE should refer to CRITFC's Opening Brief in UM 2273 regarding implementation of House Bill 2021 (CRITFC Opening Brief UM 2273). In particular, Section I, Section II.B and Section II.D.	9.2	Tribal engagement

Comment Source	Comment	Sec #	Section
CUB	PGE should include the Additional EE that was selected in portfolio analysis within the Action Plan. CUB is open to discussing securitization over financing, and requests additional information on securitization of EE.	3.1, 3.2	Action Plan, Portfolio considerations
CUB	PGE should explain in more detail how its proposed CEP actions result in environmental and health benefits from expected GHG reduction	5.1	Informational CBIs
CUB	PGE should explain in more detail how its proposed CEP actions effect the reliability and resiliency of the electric system	5.1	Informational CBIs
CUB	CUB is interested in further information around how community engagement (from EJ communities, CBAIG) was factored into Community Benefit Indicator (CBI) development.	9.1	Outreach and engagement
CUB	CUB would like to see more ways that the Company can connect specifically with community members (e.g., after hours) to offer information on how CEP and IRP projects and programs affect individual customers lives.	9.1	Outreach and engagement
CUB	PGE should work with community organizations on coordinating meeting spaces/engagement opportunities that engage more community members, specifically underserved and EJ communities. Information should be less technical/connected to their daily lives and interests.	9.1	Outreach and engagement
CUB	CUB believes that... PGE could provide a summary of its proposed portfolio specifically related to how its IRP plan will impact customers, particularly for those communities that may be impacted by future CBRE projects and resource procurement.	9.3	Accessibility
CUB	Communities are focused on how traditional utility planning processes directly impact customers, especially low-income customers, communities of color, and other frontline communities. ...incorporate a section dedicated to how IRP and CEP plans directly impact these customers' daily lives.	9.3	Accessibility
CUB	We also encourage the utility to utilize the UCBIAG in the creation of future CEPs to help with overall CEP accessibility.	9.3	Accessibility
CUB	PGE should restructure its typical outreach techniques to focus less on the technical and macro level information and to focus specifically on how its	9.4	Feedback

Comment Source	Comment	Sec #	Section
	plans and portfolio will impact the micro level of community groups and individuals.		
CUB	What feedback from Learning Lab settings was incorporated or not incorporated into the plan, and how that engagement went beyond agenda setting for future sessions.	9.4	Feedback
CUB	CUB is also interested in understanding how stakeholder engagement and feedback was considered in these spaces. ...it is still unclear how the Company used the information from stakeholders to help inform the CEP or IRP or how changes were made to these plans based on feedback.	9.4	Feedback
CUB	PGE should file updates on its planning for use of these funds and include analyses of how it expects the applicable federal resources it utilizes will provide the 40 percent benefits and what those benefits will look like.	9.5	Tax Incentives and funding opportunities
Deep Blue Pacific	PGE should revise the Preferred Portfolio to reflect that offshore wind is part of the least cost and least risk Preferred Portfolio.	6.2	Model specifications
Deep Blue Pacific	PGE should conduct an RFP for long lead-time resources in order to send market signals to developers of offshore wind and other long lead-time resources.	7.4	Timing
Energy Advocates	A technical workshop on the CEP/IRP transmission options is needed.	2.1	Comprehensive transmission response
Energy Advocates	There are concerns that the transmission proxy resources are in the Preferred Portfolio too soon given the time it takes to develop transmission projects.	2.1	Comprehensive transmission response
Energy Advocates	More information is requested regarding the cost of out-of-region transmission proxies and if costs have been updated.	2.3	Proxy Transmission Cost
Energy Advocates	PGE should include of the Additional EE that was selected in portfolio analysis within the Action Plan.	3.1	Action Plan
Energy Advocates	Highlighted the disadvantages of financing and raised questions about cost-effectiveness and PGE role in determining the quantity of EE to be procured.	3.2, 3.3	Action Plan, Planning and execution
Energy Advocates	As more VERs and demand side resources enter the system PGE's operational strategies will need to evolve.	4.4	Operations

Comment Source	Comment	Sec #	Section
Energy Advocates	PGE is asked to provide details of the CEP/IRP economic dispatch and recommended to include the social cost of carbon and health benefits in this dispatch.	4.4	Operations
Energy Advocates	The projected total (retail + wholesale) GHG emissions are too high in the CEP/IRP and not consistent with overall Oregon GHG targets.	4.4.2	Economic Dispatch
Energy Advocates	The AdopDER model does not account for several Oregon incentives for low-and-moderate-income households.	4.6	Input assumptions
Energy Advocates	PGE should include an additional CBI related to Tribal priorities.	5.1	Informational CBIs
Energy Advocates	PGE should seek to understand how the CEP itself advances progress in its CBIs and should include actions in the Action Plan explicitly related to CBIs.	5.1	Informational CBIs
Energy Advocates	How did PGE determine 155 MW as the maximum amount of realistic and achievable CBRE potential in the Action Plan?	5.3	Maximum CBRE potential
Energy Advocates	PGE should run a model sensitivity with higher adoption of CBRE and distributed-generation resources.	6.1	CBREs & DERs
Energy Advocates	PGE should be required to model a portfolio that selects 125 percent of the maximum stated attainable CBRE resources.	6.1	CBREs & DERs
Energy Advocates	Can PGE clarify where the analysis of High and Low Need Futures can be found?	6.2	Model specifications
Energy Advocates	PGE should model early Colstrip exit and modify the Action Plan accordingly.	6.2	Model specifications
Energy Advocates	PGE's CBRE actions should go beyond an RFP to include additional approaches to acquire CBREs that are unlikely to bid into an RFP due to the resources required to submit a bid.	7.1	CBREs
Energy Advocates	Add energy justice focused items/actions to the Action Plan and to future CEP/IRPs.	7.1	CBREs
Energy Advocates	The scoring criteria for RFPs should include CBIs or other non-price factors to maximize benefits for environmental justice communities.	7.3	Scoring
Energy Advocates	We also ask the Commission to direct PGE to utilize the UCBIAG to continue to facilitate, and improve on, other community engagement efforts.	9.1	Outreach and engagement

Comment Source	Comment	Sec #	Section
Energy Advocates	PGE should take a more thorough approach to Tribal Engagement: how will PGE accomplish their goal to "[b]Build awareness, inform..." or "Increase community participation, including Tribal..."; prioritize finding a Tribal representative for the CBIAG; consider the CRITFC Energy Vision.	9.2	Tribal engagement
Energy Advocates	Increase accessibility of all or part of future CEPs.	9.3	Accessibility
Energy Advocates	PGE should track the feedback it receives and how it uses it.	9.4	Feedback
GEI	Provides recommendations for how PGE can communicate facts to retail customers regarding energy and its GHG content.	8.3	RECs
Grid United	The two CEP/IRP proxy transmission resources do not capture all interregional benefits of new transmission, and an interregional proxy resource that would provide these benefits should be included in future planning work.	2.4	Options
NewSun	The Desert Southwest and Wyoming Wind transmission proxies may not be technically feasible in the CEP/IRP timeline.	2.1	Comprehensive transmission response
NewSun	The OPUC should host a workshop on transmission and discuss if the BPA options and TSRs in the CEP/IRP are still available.	2.1	Comprehensive transmission response
NewSun	More information is requested regarding the out-of-region proxy transmission development and costs, if these costs are reflective of costs found on the market, and concerns are expressed that the costs may be low.	2.3	Proxy Transmission Cost
NewSun	PGE should curtail thermal plant usage when those plants are being run for non-PGE load.	4.4.2	Economic Dispatch
NewSun	PGE has not adequately addressed CBRE technical achievable potential in its modeling and should model up to 125 percent of the currently assumed potential.	6.1	CBREs & DERs
NewSun	PGE should run a model for distributed energy resources up to their achievable potential.	6.1	CBREs & DERs
NewSun	PGE should provide draft avoided cost information in the same format as will be provided in final form following IRP acknowledgement.	8.2	Avoided cost information

Comment Source	Comment	Sec #	Section
OPUC	PGE is invited to provide additional details regarding its long-term decarbonization strategy.	1.1	Clean energy plan
OPUC	Does the CEP/IRP decarbonization strategy require future market interactions and participation?	1.1	Clean energy plan
OPUC	At what junctures might PGE consider material changes to the CEP/IRP decarbonization strategy?	1.1	Clean energy plan
OPUC	What information and data will be used to determine if a change in course for the decarbonization strategy is needed?	1.1	Clean energy plan
OPUC	What are the circumstances that could result in poor outcomes for customers due to PGE's planned decarbonization strategy actions?	1.1	Clean energy plan
OPUC	Are there any decarbonization strategy actions excluded from the CEP/IRP due to poor outcomes for customers?	1.1	Clean energy plan
OPUC	PGE should provide additional detail/information about its near-term Tx action items like SoA congestion relief and Bethel-Round Butte upgrades.	2.1	Comprehensive transmission response
OPUC	PGE should explain and provide more information on its long-term transmission strategy for complying with HB 2021.	2.1	Comprehensive transmission response
OPUC	Recommendation 18 - Including the 50MWa of additional EE in the Preferred Portfolio and describing the strategy to procure the additional EE within the Action Plan window.	3.1	Action Plan
OPUC	Recommendation 19 - PGE should provide an update on its collaborative efforts with ETO towards procuring additional EE resources by 2030.	3.1	Action Plan
OPUC	OPUC note concerns about the avoided cost information provided for energy efficiency.	3.4	Avoided costs within UM 1893
OPUC	Why is the ELCC value of the Gorge Wind proxy resource higher than in the 2019 IRP Update?	4.2	ELCC values
OPUC	Why are there differences between tuned and untuned ELCC values in the CEP/IRP?	4.2	ELCC values
OPUC	PGE should test the adequacy of the Preferred Portfolio and report the LOLH and LOLE metrics associated with it, and explain why it chose to plan for that level of adequacy.	4.3	Resource adequacy

Comment Source	Comment	Sec #	Section
OPUC	PGE should account for the benefits of the WRAP in future CEP/IRPs.	4.3	Resource adequacy
OPUC	Due to concerns that the annual GHG emissions accounting approach is insufficiently detailed (and may lead to a system that does not comply with emission targets) an hourly emissions analysis is requested.	4.7	Temporal granularity
OPUC	Recommend the inclusion of additional iCBIs specific to Tribal priorities	5.1	Informational CBIs
OPUC	PGE should provide a supplemental analysis that satisfies the HB 2021 requirement to examine the costs and opportunities of offsetting energy generated from fossil fuels with community-based renewable energy.	5.5	CBRE trade-offs
OPUC	PGE should provide insight into the level at which CBRE additions are no longer low regrets actions and tradeoffs of including different levels of CBREs in portfolio analysis.	5.5	CBRE trade-offs
OPUC	PGE should provide an interim pCBI that captures the different benefits across all resource types across all portfolios.	5.6	Portfolio CBIs
OPUC	PGE should update its portfolio scoring analysis to express pCBIs in dollar terms.	5.6	Portfolio CBIs
OPUC	PGE should provide additional analysis that decreases the annual capacity limit imposed in portfolio modeling to explore the cost and risk implications of spreading out capacity additions to meet 2040 needs.	6.2	Model specifications
OPUC	How have the capacity additions in the Preferred Portfolio informed PGE's long-term decarbonization strategy as it relates to acquiring non-emitting capacity over time?	6.2	Model specifications
OPUC	It is unclear whether the inclusion of Colstrip in the portfolio beyond 2025 appropriately balances cost, risk, the pace of GHG reductions, and community impacts because no early-exit portfolio was analyzed.	6.2	Model specifications
OPUC	PGE should re-design and re-evaluate the Preferred Portfolio without assuming up to 800 MW of transmission expansion access.	6.3	Preferred Portfolio
OPUC	PGE should adopt a scoring metric for the pace of GHG reductions to show the tradeoffs between cost, risk, the pace of GHG reductions, and community impacts and benefits across portfolios.	6.4	Scoring metrics

Comment Source	Comment	Sec #	Section
OPUC	PGE should design a scoring metric for near-term cost impacts that can be applied across all portfolios and justify its use in planning and procurement decisions.	6.4	Scoring metrics
OPUC	In the future, PGE should justify portfolio analysis findings and design principles used to develop the Preferred Portfolio based on all scoring metrics, not just those that address cost and risk.	6.4	Scoring metrics
OPUC	First, does PGE plan to pursue CBRE technologies beyond the proxy resource types included in the CBRE potential study? Second, what is PGE's strategy to balance CBRE acquisition costs while maximizing community benefits; specifically considering strategy to leverage funding resources and other partnerships, and key emerging risks and decision points. Third, what steps can PGE take to overcome implementation risks and ensure that company resources associated with CBRE procurement activities are used effectively.	7.1	CBREs
OPUC	PGE should provide additional detail on proposed RFP framework, including the specific methodology to update the needs assessment, potential offramps, and how PGE will make a determination to close one round of procurement and begin another.	7.2	Procurement levels
OPUC	PGE should describe how the Company will respond if an RFP does not result in its targeted procurement level.	7.2	Procurement levels
OPUC	PGE should provide regular updates to LC 80 participants on its target procurement volume for the 2023 RFP as new information and analysis warrant.	7.2	Procurement levels
OPUC	Does the RFP pacing and supply chain analysis provide quantitative insights into resource acquisition pacing options and does PGE plan to constrain annual RFPs to match the annual RFP scenario energy and capacity additions?	7.4	Timing
OPUC	PGE should provide additional detail on its approach to small-scale renewables, including compliance position, detail for specific resource types and discussion of acquisition strategy.	8.1	Small scale renewables requirement

Comment Source	Comment	Sec #	Section
OPUC	How might PGE realize value from an expected increase in the size of the REC bank through time as the number of RECs produced annually exceed the amount needed for RPS compliance?	8.3	RECs
OPUC	Recommendation 4: In Reply Comments, PGE should explain what steps it is taking for this IRP/CEP, and can take in the future, to communicate its HB 2021 compliance strategy in a manner that is accessible and meaningful to the customers and communities it serves.	9.3	Accessibility
OPUC	Recommendation 3: In Reply Comments, PGE should provide a table that identifies key feedback received by community and other stakeholders, the affiliation of the person providing the feedback, whether and where PGE incorporated the feedback, and why.	9.4	Feedback
OSSIA	PGE should provide draft avoided cost information in the same format as will be provided in final form following IRP acknowledgement.	8.2	Avoided cost information
REC	PGE should change the CEP/IRP assumptions regarding QF renewals and should change the success rate applied to contracted but not online Schedule 202 resources.	4.6	Input assumptions
REC	PGE should only include energized community solar projects in the CEP/IRP.	4.6	Input assumptions
RNW	The CEP/IRP transmission modeling is overly generic and does not demonstrate which projects are best, the timeline is quick, offshore wind should be considered for congestion relief, and merchant transmission should be considered.	2.1	Comprehensive transmission response
RNW	PGE should rethink how conditional firm 200hr transmission is modeled and not include any hours of curtailment.	2.2	Conditional firm transmission modeling
RNW	For the next planning cycle the ELCC methodology should take the portfolio effect into account, among other suggested changes.	4.2	ELCC values
RNW	For the next planning cycle, the resource adequacy capacity assessment method should examine more planning metrics, calculate capacity need differently, and other suggestions.	4.3	Resource adequacy
RNW	For the next planning cycle, the resource adequacy model should use more granular market power import assumptions.	4.3	Resource adequacy

Comment Source	Comment	Sec #	Section
RNW	PGE should provide a discussion and comparison of the WRAP and CEP/IRP adequacy, integrate WRAP data into CEP/IRP processes, and work to align the processes.	4.3	Resource adequacy
RNW	Sub-annual emissions accounting is requested, in part due to the risk of overgeneration, curtailment, emissions netting, and VER integration not being properly addressed with annual analysis.	4.5	Emissions accounting
RNW	Power plant Beaver's change in generation between the filed CEP/IRP and the Addendum is evidence of resource "shuffling."	4.5	Emissions accounting
RNW	PGE is "shuffling" GHG emitting resources to swap higher GHG intensity resources for lower intensity ones.	4.5	Emissions accounting
RNW	In the CEP/IRP PGE advocated for changing the market unspecified CO2e emissions rate.	4.5	Emissions accounting
RNW	PGE's CEP/IRP decarbonization modeling is compared to modeling done by other organizations.	4.5	Emissions accounting
RNW	Hydrogen input assumptions are requested, and recommendations on how to model hydrogen are provided.	4.6	Input assumptions
RNW	PGE should adopt an hourly or systems-level analysis of its emissions target.	4.7	Temporal granularity
RNW	PGE may be underestimating GHG emissions due to the need for thermal resources to provide ancillary services, and those services not being captured under the current modeling timestep.	4.7	Temporal granularity
RNW	PGE's plan should have thorough and direct incorporation of energy justice principles and conversations.	5.1	Informational CBIs
RNW	PGE should be able to clearly attribute changes in CBIs to specific CBRE actions and include tribal and environmental iCBIs.	5.1	Informational CBIs
RNW	There is a need for more capacity building and resources in under-resourced communities for them to gain experience and an ability to engage in planning and building CBRE projects.	5.2	CBRE community engagement
RNW	PGE should incorporate a clean capacity glidepath within portfolio modeling to smooth the transition away from GHG-emitting resources and prevent the risk of “hockey stick” transitions in resource additions at critical milestones.	6.2	Model specifications

Comment Source	Comment	Sec #	Section
RNW	The IRP does not test the economic value of offshore wind because the offshore wind portfolio in the IRP cannot be compared to portfolios containing transmission expansion.	6.2	Model specifications
RNW	Offshore wind is part of the least-cost and least-risk portfolio and should be included in the Preferred Portfolio.	6.2	Model specifications
RNW	A portfolio that includes offshore wind and other non-generic resources makes a more interesting and relevant comparison than PGE's Preferred Portfolio.	6.2	Model specifications
RNW	Modeling specific rather than generic resources would provide clarity on post-2030 resources and send better market signals to developers.	6.2	Model specifications
RNW	The Preferred Portfolio should contain specific resources rather than generic resources.	6.2	Model specifications
RNW	PGE appears to not be fully accounting for all the factors considered by NREL in the calculation of offshore wind costs, producing conservatively high costs after 2030.	6.5	Supply-side options
RNW	Offshore wind should not be characterized as an emerging technology.	6.5	Supply-side options
RNW	PGE should conduct an RFP for long lead-time resources in late 2025 for acquisition of resources in the early 2030s.	7.4	Timing
RNW	Still like to see a specific plan to ensure that historically excluded and underserved communities will be included in future engagement.	9.1	Outreach and engagement
RNW	Continue to provide information on the progress of Tribal engagement as well as any other efforts beyond the Strategic Tribal Engagement Plan that PGE may pursue in working with Tribes.	9.2	Tribal engagement
Swan Lake	The assumption of a 38-year useful life used in PGE's derivation of pumped hydro cost estimates is too short and Staff should direct PGE to re-run portfolio analysis using a 50-year life and evaluate a 75-year sensitivity.	6.5	Supply-side options

Appendix B: Strategic Tribal Engagement Plan

Last year (2022), we created our inaugural Strategic Tribal Engagement Plan (STEP) to assist with Tribal relations and establish an internal and external process for engagement. The STEP provides a framework for our teams to develop and maintain successful Tribal relationships by setting goals, identifying actions and implementing best practices to meet desired outcomes.

Strategic Tribal Engagement Plan

Acknowledgment

"Everywhere you are, Indians have been...
Every hill, every creek, every meadow, every forest,
every inch of Oregon has a story of its connection
to the indigenous peoples who lived here."

— Testimony of Jeremy Fivecrows (Nez Perce)
to Portland City Council, 2005

We take this opportunity to honor the Indigenous Peoples who continue to care for the lands that we work in since time immemorial, and who continue to remind us that living in a place creates responsibilities to the water, air, animals, land and its people.

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Introduction

PGE is committed to proactive, strategic, and effective Tribal engagement and partnership in recognition of Tribal sovereignty. As a company, we have deep respect for Tribal wisdom, worldviews and work. Developing a programmatic approach to Tribal relations will ensure that meaningful Tribal engagement is standard practice across PGE. PGE's Strategic Tribal Engagement Plan (STEP) provides a framework for PGE's approach to working with Tribes.

Purpose of STEP

PGE's STEP provides a framework for PGE teams to develop and maintain successful Tribal partnerships by setting goals, identifying actions and implementing best practices to ensure desired outcomes through Tribal relations.

This document is intended for PGE employees who work with Tribes, to provide consistency in how we approach Tribal relations. PGE is invested in and thoughtful about our Tribal engagement strategy, which informs our work at the highest level. This document does not replace any existing guidance specific to individual work spheres.

PGE currently has the opportunity to work closely with federally recognized Tribes in Oregon, Washington and Idaho, including:

- Confederated Tribes of Grand Ronde
- Confederated Tribes of Siletz Indians
- Confederated Tribes of the Umatilla Indian Reservation
- Confederated Tribes of Warm Springs
- Confederated Tribes and Bands of the Yakama Nation
- Cowlitz Indian Tribe
- Nez Perce Tribe

In the future, we may have the opportunity to engage with other Tribes not listed above. Tribes are PGE's customers, business partners, stakeholders and regulators. As such, PGE's mission is to be thoughtful and strategic when working with Tribes. We are a leader among businesses nationally in Tribal consultation and partnerships.

Alignment with PGE strategy

We acknowledge that our journey toward a clean energy future must include Tribes as partners. Tribes are sovereign governments, economic drivers, political influencers and nation builders. PGE's service territory and generation sites are part of Tribal Ceded[1] and Usual and Accustomed[2] lands. The Confederated Tribes of Warm Springs has been PGE's business partner on the Pelton Round Butte hydroelectric project for over six decades. The Confederated Tribes of Grand Ronde are one of our key customers. Tribal governments support the regulatory process when they review PGE's environmental and licensing permits. All regional Tribal governments act in a stakeholder capacity and review our Federal Energy Regulatory Commission (FERC), Energy Facility Siting Council (EFSC) and other licenses and permits. We work closely with Tribes to negotiate franchise agreements for transmission lines. Our service territory and generating areas are also home to multiple individuals and communities who identify as Native American and Alaska Natives. Last but not the least, individuals who identify as Native American are part of our employee workforce.

As such, Tribal relations are a critical part of our company's overall strategy and operations. We have multiple touch points with Tribes across the company, be they in Operations, Public Affairs, Transmission Services, Strategy and Integration, Distributed Systems Planning, Key Customer, Power Operations, Environmental and Licensing, including fish passage, recreation facilities or managing our cultural resource impacts. Moreover, it aligns with PGE's Diversity, Equity and Inclusion best practices.

STEP is one tool that strengthens PGE's overall purpose

We exist to power the advancement of society. We energize lives, strengthen communities, and drive advancement in energy that provides social, economic and environmental progress.

Our company vision is to lead the clean energy future. Together with our customers, stakeholders, and communities, we will lead the energy transformation by decarbonizing, electrifying, and performing. As an important and multifaceted demographic, Tribes and Tribal interests are intrinsically connected to our imperatives. PGE's success with Tribal relationships will help our path towards our three long-term imperatives — decarbonize, electrify and perform.

1. *Ceded lands: Areas where a Tribe did "cede, relinquish, and convey to the U.S. all their right, title, and interest in the lands and country occupied by them" at treaty signing or when reservations were established.*
2. *Usual and Accustomed lands: Lands within and adjacent to areas to which a tribe(s) usually traveled or was accustomed to travel to hunt, fish, gather roots and berries or for any other cultural or spiritual purposes.*

STEP goals

PGE's Strategic Tribal Engagement Plan describes three goals to ensure desirable outcomes:

1. **Tribal sovereignty**
2. **Tribal partnerships**
3. **Program weave**

Tribal sovereignty

Ensure the company learns, understands and respects Tribal legal interests and perspectives as they pertain to PGE's strategy and operations. And how those operations may directly or indirectly impact Tribal governments and their members.

OBJECTIVE	ACTION	OUTCOME
Support the company's understanding of Tribal perspectives and its application to our responsibilities of consultation.	Provide STEP training to heighten cultural competence and humility on Tribal rights, federal and state law, Tribal history, cultures, traditions and best practices to company leaders, key managers and appropriate staff whose work interfaces with Tribes.	Policy and resource management decisions that appropriately integrate Tribal rights and interests.
PGE staff to engage with Tribes in substantive and meaningful consultation in support of PGE objectives.	1. Develop best practices for Tribal consultation. 2. Educate staff to identify and advance Tribal partnership opportunities. 3. Evaluate emerging policy issues with Legislative Affairs staff and provide recommendations. Confer annually with Tribal leaders and staff to identify emerging policy and project work to proactively address Tribal consultation requirements.	Meet and exceed compliance with required regulations around Tribal outreach and consultation.

Tribal partnerships

Leverage partnerships to maximize mutual success.

OBJECTIVE	ACTION	OUTCOME
Identify partnership opportunities with Tribal governments, inter-Tribal organizations, Tribal Affairs teams in other organizations, Tribal community organizations and Tribal employees to further PGE's strategic goals of decarbonization, electrification and performance.	Identify, organize, and participate in relevant events and programs that offer networking and relationship-building opportunities between PGE and Tribal personnel.	1. Increase mutual trust between Tribes and PGE, which provides a foundation for long-term successful partnership. 2. PGE's management decisions and actions appropriately consider Tribal issues. 3. Enhanced capacity building in Tribal communities.

Program weave

Promote integration and use of STEP throughout the company.

OBJECTIVE	ACTION	OUTCOME
STEP is effectively integrated into PGE's programs that interface with Tribes.	1. Provide STEP Training to identified staff. 2. Advise leadership on relationship building, communications and messaging in speeches, briefings and updates, where appropriate. 3. Co-organize on-the-ground events and opportunities with PGE leadership and Tribes. 4. Identify opportunities to highlight STEP at trainings, conferences and professional society meetings.	1. Increased awareness of Tribal concerns and needs, and PGE's success in addressing those appropriately. 2. Tribes regard PGE as an engaging partner across horizontal and vertical lines, with appropriate alignment and relationships between individuals at the right level.

STEP roles

At PGE, every employee has an opportunity to be a champion of Tribal relations. We encourage learning about area Tribes, developing a deep regard and respect for Tribal worldviews and being a diligent company representative.

There are several roles that are responsible for PGE's Tribal relations. These are generally described below.

Tribal Liaison

PGE's Tribal Liaison is part of the company's Government Affairs team. This position is responsible for the overall programmatic implementation of PGE's STEP. It reports to the Director of Government Affairs. Primary responsibilities of the Tribal Liaison include:

EXTERNAL

- Conduct regular and sustained outreach to Tribal government, leadership and staff in support of PGE's initiatives.
- Identify common interests with Tribes when consistent with PGE's overall objectives.
- Coordinate PGE involvement and Government Affairs efforts as needed in federal, state, local agency and community forums on legislative efforts and other matters related to Tribal issues or interests.
- Establish and maintain favorable strategic relationships with state and federal agency personnel, other utilities, customer representatives and interest groups on issues of mutual Tribal interests.
- Serve as a company spokesperson at appropriate forums; represent PGE at Tribal events.
- Organize and host meetings with Tribal Leaders and PGE leadership and staff.

INTERNAL

- Provide expertise and timely support to other PGE groups on Tribal matters, including supporting business initiatives with Tribes.
- Monitor and report on topical or pertinent regional and national Tribal energy issues.
- Maintain awareness of regional inter-tribal relations.
- Advise front line staff and key managers who interact with Tribes on conflicting/competing interests or possible impacts of proposed PGE actions on Tribes.
- Develop training materials for use by PGE management and staff on Tribal relations.
- Regularly report to management on status of major initiatives, agency rulemakings or similar proceedings, and activities related to Tribes.
- Assist in NEPA or NHPA Section 106 consultation where Tribes' interests intersect with regional issues where likely to be political or sensitive.
- Review major communication going to Tribes.
- Be aware of Tribal issues imminent in other parts of the company and support staff, as needed.
- Serve as a facilitator with Tribes that we do not have relationships with currently.
- Serve as a cultural consultant and advise on culturally appropriate responses for a variety of events such as seasonality of communications, the death of a Tribal leader, elder or community member.
- Advocate to preserve confidential Tribal files, photos and records with PGE's Records and Information Management (RIM) team to create a virtual and physical storage system for Tribal records with controlled access. Note that privileged documents are handled separately by PGE Legal which has its own document storage system.

When should PGE's Tribal Liaison be involved?

- Any direct communication with Tribal leaders, elected Tribal positions or Tribal elders.
- Projects that have connections between Tribal interests and a larger PGE issue or strategy.
- Issues with ongoing litigation involving Tribes where appropriate.
- NEPA and NHPA consultation involving a Tribe with issues where likely to be political or sensitive.
- Sensitive Tribal issues involving but not limited to burials, human remains, Traditional Cultural Properties (TCPs) and Historical Properties of Cultural and Religious Significance to Indian Tribes (HPCRIT).
- When a new Tribal point of contact needs to be identified.
- New transmission interconnect requests from potential developers on Tribal lands.
- Legislative issues involving Tribes.
- Tribal issues with potential regional trigger.
- Tribes have interest in PGE property.
- Property disputes involving Tribes.
- Identifying the right Tribes on specific projects.
- Tribal elders or Tribal leadership are invited to PGE's facilities.

Director, Public Affairs

- Provides regular oversight to STEP and Tribal Liaison.
- Has overall oversight of STEP program.
- Leads key PGE communications to federal and state delegations, Governor's office or other elected officials on Tribal issues.
- Advises, supports and advocates for effective Tribal consultation at appropriate levels.
- Present at social and cultural gatherings with area Tribes.
- Cover for Tribal Liaison when they are not available.

Vice-President, Public Affairs

- Executive sponsor of STEP.
- Involved in high-risk and high-visibility issues pertaining to Tribes.
- Key advocate on Tribal relations to PGE leadership, including CEO.
- Primary communicator to Tribal Council members and other Tribal leadership when executive engagement is needed.
- Represents PGE at high-profile meetings, visits, and cultural and traditional events when Tribal dignitaries are present.
- Present at annual social and cultural gatherings with area Tribes.

CEO

- Represents PGE in strategic communication to Tribal chairs and elders, as appropriate.
- Present at high-profile meetings, visits, and cultural and traditional events when Tribal dignitaries are present.
- Present at annual social and cultural gatherings with area Tribes.

Legal team

- Will be involved whenever a Tribe is represented by legal counsel and whenever a communication is to or between PGE and Tribal lawyers.
- Leads discussions and authors communication related to dispute negotiations, resolutions, mediation and litigation involving Tribes.
- Reviews legal documents to and from Tribes.
- Oversees communication from other departments to Tribes when issues have potential legal impacts.
- May be involved in other actions and activities as part of advising clients.

Technical staff

PGE technical staff correspond and interact with Tribal technical staff on routine issues or tasks. These include routine FERC and EFSC filings, routine project correspondence to lead federal agencies, established coordination on plant operations, key customer manager communication on routine issues, standard consultation, preservation of confidential Tribal files, photos and records, coordinating access for Tribal staff to PGE facilities or routine franchise agreements.

Technical staff include the following departments:

- Operations
- Company hydrolicensing (biological, cultural, recreation)
- Cultural Resources
- Corporate Communications
- Structure and Origination
- Property
- Record and Information Management (RIM)
- Office of Diversity, Equity and Inclusion
- Key Customer Manager

The above are broad guidelines for Tribal engagement and there might be circumstances where various PGE groups play different roles based on the issue.

Tribal consultation best practices

> "I would consider any consultation successful in which there has been a collaborative effort and all parties acknowledge and respect the observations, comments and concerns of the other."
>
> *— Dr. Richard L. Allen, Policy Analyst, Cherokee Nation*
> *A Traditional Cultural Property of New Echota*

While PGE does not have government-to-government consultation mandates, we may seek delegated authority from federal agencies to conduct Tribal consultation, in support of environmental and cultural resources protection laws, including National Environmental Policy Act (NEPA) and National Historic Preservation Act (NHPA). PGE also undertakes numerous informal consultations for projects in areas of significance to Tribes for historical, cultural, religious or spiritual reasons. Tribes have traditional ecological knowledge (TEK) owing to their deep connections to place as stewards since time immemorial. With proactive consultation, PGE stands to better understand Tribal geographic landscapes and their elements, which help us make well-informed decisions during planning, design and execution of our projects.

For consultation to be successful, it should be ongoing, timely and ensure positional equity.

DO THE HOMEWORK

The basis for effective Tribal engagement is a foundational knowledge of the Tribes that we are working with. Learning about Tribal culture will help us appreciate Tribal worldviews and understand Tribal behaviors. This includes the Tribes' governance structure, food preferences, spiritual practices, natural resource values, family structure, education system, territorial interests (which may and often do overlap), legal rights and authorities and Tribal economic engines.

- When you know one Tribe, you know only that one Tribe. Every Tribe has its unique culture, governance and social structure as it is a product of its unique geography, history, legal status, treaties, rights, interests and other factors. For example, Tribes such as the Yakama Nation and the Nez Perce were largely single groups that stayed intact. Other disparate groups were lumped into large Confederations and therefore experienced different historic trajectories. Tribes can also differ depending on whether their treaties were made during peace or during war, what their relationship with the federal government has been, whether their membership are beneficiaries of a per capita model or a service model and what kind of alliances they have nurtured with neighboring Tribes. Tribes' legal history, including termination and restoration, can be another compounding factor. Some Tribes have sizable economic establishments and investments, while others, such as the Burns Paiute Tribe of Oregon — the smallest Tribe in the country with 410 members — have a single source of Tribal income. Therefore, it is very important to avoid generalizations.

- Understand each Tribe's governance model and decision-making process. These vary widely between Tribes and are key determinants of successful consultation. Gaining an appreciation of meeting protocols related to prayer, seasonality, food sharing and gift giving are a few practices that may affect consultation outcomes. Tribes often have two tiers of government including a legal/political tier and traditional approach. The tribal representative is not always the decision-maker.
- Tribes themselves are the best source of information about their past, present and future. Staff are encouraged to go to the official Tribal website to hear their own story. Some Tribes have museums and public relations staff that are willing to provide information. It is critical to provide sufficient time to solicit all views from a Tribe and to allow adequate time for a Tribe to gather views from its members, staff and leadership.
- Understand the Tribe's perceptions of time and allow enough time to form ongoing relationships. Perceptions of time vary across cultures. Non-native sense of time is often more linear compared to Tribal seasonal rhythms, ceremony and grieving periods. PGE staff should be aware of differences and work to accommodate Tribal schedules. Likewise, PGE staff should be clear with Tribal contacts about any exigent circumstances driving our schedule. Further, consider that true collaborative decision-making may take a long time.
- Acknowledge that Tribes have a long history of broken commitments made by federal and state partners. Trust is a critical element of any Tribal relationship.

INCORPORATE TRIBAL OUTREACH INTO PROJECT PLANNING

Beginning Tribal consultation as early as feasible is paramount.

- Distinguish Tribes from stakeholders, environmental groups and nonprofit organizations.
- Identify the Tribes who need to be part of a project. Use both official sources, such as Commission on Indian Services (CIS), and informal sources, such as Tribally-identified Usual and Accustomed land boundaries and natural features that Tribes consider for property demarcation.
- Consult official consultation guides that some Tribes maintain.
- Budget resources and time for building relationships before decisions are required. Establish the formal and informal preliminary contacts and the appropriate authorities needed for proceeding. Assess and define roles, organizational attributes and explicit procedures. It is in PGE's interest to work toward building Tribal capacity. It is recommended that we consider if there are opportunities for PGE to help build institutional capacity through our projects. Consider and plan for compensation/participation funding for Tribal input and engagement in PGE projects. Construct flexible protocols while planning projects. These protocols will allow tribes to execute on their own contributions with due consideration of project resources and procedural fairness.
- In case of anticipated conflict, PGE should make efforts to establish procedural neutrality, including using independent facilitators.
- PGE's project managers should have a plan to protect sensitive and confidential Tribal information.
- Do not depend overly on lead federal agencies for consultation outcomes. PGE must play an active role with Tribes throughout a project.
- For NEPA projects, sometimes Tribal consultation may be appropriate even if a proposed action is covered by a Categorical Exclusion that relieves the lead federal agency of the need to prepare an Environmental Impact Study (EIS) or an Environmental Assessment (EA). PGE should take care to consider that the proposed action covered by the categorical exclusion does not involve "extraordinary circumstances" relating to potential impacts to Tribal land uses, access, or cultural or religious values, as articulated in the Council on

Environmental Quality and Department of the Interior's NEPA regulations. If for any reason a NEPA document will not be prepared, an appropriate non-NEPA document should be used for consideration of Tribal concerns. Such non-NEPA documentation may consist of Tribal consultation logs or data recovery reports.

- PGE's licensing and cultural resources staff must contact their Tribal counterparts prior to sending out permits for their official review and approval.
- When feasible, offer to travel to Tribal Offices recognizing that resource issues may be affecting a Tribe's participation. It is appropriate to consider paying for costs associated with consultation.

CONSULTATION AND COLLABORATION

At PGE, we regard consultation as an ongoing process conducted in a timely, intentional, and respectful two-way manner. Successful consultation begins early in the planning stages and is predicated on both PGE and the Tribes being knowledgeable about the project and priorities.

- Respect tribal sovereignty and self-determination and be aware that Tribes have discretion and control over their means of reaching desired outcomes according to their own cultural values and norms.
- Be aware that Tribal authority can be nested in many layers, both formal and informal, and can change over time. Formal authority may rest with Tribal Council, committees or commissions, regulatory offices or Tribal Historic Preservation Officer (THPO), but at times elders alone may be the authority to speak on oral traditions and cultural matters. Also, it will be necessary to clarify if individual leaders can speak on behalf of the Tribe.
- When meeting with Tribes, positional compatibility and horizontal alignment between roles must be followed.

Tribal governments, tribally recognized experts, and a Tribe's view of itself as well as of its past, present and future, all legitimately represent a Tribe's interests. Accordingly, each Tribe has the discretion to collect and manage its data according to its own standards and practices.

Next steps

PGE has identified several promising implementable initiatives as part of STEP. These are organized around projects, processes, programs and policies.

PROJECT	LEAD TEAM	CROSSFUNCTIONAL TEAMS
Tribal Ecological Knowledge projects (TEK)	Wildfire Mitigation and Resiliency	Government Affairs Cultural Resources
Community volunteer projects with Tribes (GED completion, STEM)	Corporate Social Responsibility	Government Affairs
Tribal art installations at PGE locations	Facilities Management	Property Government Affairs
Support relevant exhibits at Tribal Museums	Cultural Resources	Government Affairs

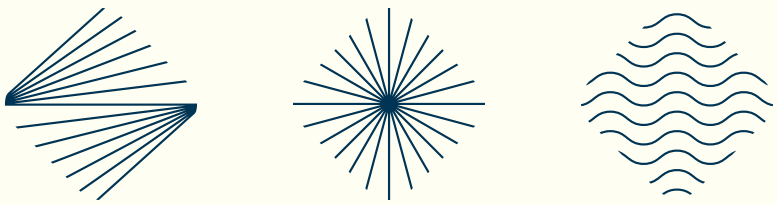
PROCESS	LEAD TEAM	CROSSFUNCTIONAL TEAMS
Apply equity lens to supplier diversity and PGE Foundation grant process	Supply Chain	DEI Government Affairs
Land Acknowledgement Statement	Government Affairs	DEI Brand Marketing Communications
Observe Oregon's Indigenous Peoples Day	Government Affairs	Brand Marketing Communications
Consider blessing ceremony/ethnographic place names at new PGE locations (generations, substations, parks)	Facilities Management	Property Legal Government Affairs
Replanting with traditional plant species	Vegetation Management	Environmental Landscaping
Consider cultural easement	Properties	Legal Government Affairs
Invite Tribes to Environmental Roundtable	Environmental	Government Affairs

PROGRAM	LEAD TEAM	CROSSFUNCTIONAL TEAMS
STEM Training	Government Affairs	HR — Learning and Development
Incorporate Tribal history into Parks Junior Ranger Program	Environmental-Parks	Brand Marketing Communication
Recruit Tribal members for cultural resource monitor positions	Cultural Resources	HR
STEM partnership with Tribal schools	Corporate Social Responsibility	Government Affairs
Line Apprentice program for Tribal youth	HR Workforce Planning	HRBPs Line Apprenticeship Program DEI Government Affairs
Internship Program. Partner with the American Indian Science and Engineering Society (AISES), NRCS and DOE. Recruit from native conferences and posting with appropriate job boards/schools like Tribal Colleges to further recruit Native employees	Corporate Social Responsibility, Project Zero	HR
Continue agreements to provide hands-on training to help Tribes run their own hydroelectric operations, hands-on training on PGE's trading floor and power operations.	HR	Government Affairs
Tribal fire crews work in our vegetation management program in fire off-season	Vegetation Management	HR Legal
Establish Native American BRG at Pelton Round Butte	DEI	Brand Marketing Communications

POLICY	LEAD TEAM	CROSSFUNCTIONAL TEAMS
Tribal community energy plans collaboration	Government Affairs	Project Symphony team
Partnerships with key Tribal organizations such as Affiliated Tribes of Northwest Indians (ATNI)'s Climate Change and Energy division	Community Impact	Government Affairs
Capacity building through START program (Strategic Technical Assistance Response Team)	Government Affairs	
Tribal mentorship through Oregon's Association of Minority Entrepreneurs	DEI	Supply Chain Government Affairs
Increase visibility of Native led and Native serving non-profit organizations during PGE's Employee Giving Campaign.		
Develop guidance for PGE employees on found migratory bird feathers and/or carcasses at our facilities to positively contribute to increasing the availability of culturally important feather materials through the eagle repository in Denver and the SIA repository for non-eagle feather materials.	Environmental-Biologists	Government Affairs

Conclusion

PGE has worked closely with Tribal governments, businesses, elders, employees, and organizations for many years. STEP provides the framework and tools to strengthen our existing relationships and forge new ones in a dynamic world. We will continue to listen to and learn from Tribes, while relaying in a timely manner information on our needs and priorities. STEP will help us have a programmatic approach to PGE's Tribal relations. Being intentional about our work with Tribes and in alignment with our overall company strategy is critical to the future of our business. Working with Tribes intentionally, in alignment with our overall company strategy, is critical to the future of our business.



An Oregon kind of energy.℠

Cover photo: Deschutes River near Pelton Dam, Madras, Oregon

10488 (8/22)

Attachment 8. PGE 2023 CEP-IRP Update filed with OPUC June 18, 2025

Portland General Electric
121 SW Salmon Street • Portland, OR 97204
portlandgeneral.com

June 18, 2025

Via Electronic Filing

Public Utility Commission of Oregon
Attention: Filing Center
PO Box 1088
Salem, OR 97308-1088

Re: LC 80 - Portland General Electric Company's 2023 Clean Energy Plan and Integrated Resource Plan Update

Dear Filing Center:

Enclosed for filing today in the above-referenced docket is Portland General Electric Company's (PGE) 2023 Clean Energy Plan (CEP) and Integrated Resource Plan (IRP) Update, pursuant to Public Utility Commission of Oregon (OPUC) Orders 24-096, 25-127 and Oregon Administrative Rule (OAR) 860-027-0400(11).

This CEP/IRP Update refreshes the analysis filed with the 2023 CEP/IRP and provides status reports on actions and requirements flowing from Commission Order 24-096.

The CEP/IRP Update does not propose any changes to the acknowledged 2023 IRP Action Plan. Furthermore, PGE is not requesting acknowledgement of this CEP/IRP Update.

Please contact Andrew Baker at 503-732-8892 if you have questions or require further information. Please direct all formal correspondence and requests to pge.opuc.filings@pgn.com.

Thank you,

/s/ Jimmy Lindsay

Jimmy Lindsay
Director, Resource Planning

Portland General Electric

2023 Clean Energy Plan and Integrated Resource Plan Update

This document contains forward-looking statements, including those regarding implementation of our business plans, technology transitions, our business, strategies and financial performance, our offerings of new services, and other statements that are not historical fact, and actual results could differ materially from these forward-looking statements. Risk factors that could cause actual results to differ are set forth in the "Risk Factors" section, as well as other sections of our Annual Report on Form 10-K, available on our website at investors.portlandgeneral.com/financial information/sec-filings, as well as, or in addition to, other filings with the SEC. All forward-looking statements are based on management's estimates, projections, and assumptions as of the date of filing, and we undertake no obligation to update any such statements.

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This document is based on the best available information at the time it was prepared but is subject to change without notice.

Portland General Electric Company
Integrated Resource Planning
121 SW Salmon Street
Portland, Oregon 97204

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Introduction

Portland General Electric Company (PGE or Company) submits this 2023 Clean Energy Plan and Integrated Resource Plan Update to inform the Oregon Public Utility Commission (OPUC or Commission) of the Company's actions since acknowledgment of the 2023 Integrated Resource Plan (IRP). The OPUC's Order 24-096 acknowledged, with conditions, PGE's 2023 IRP on April 18, 2024. Additionally, the Commission directed PGE to update PGE's Clean Energy Plan (CEP) in PGE's subsequent CEP/IRP Update.

An IRP Update addresses specific inputs that may have changed since the most recent IRP was acknowledged, without attempting to fully revise the IRP. This IRP Update refreshes the analysis filed with the 2023 IRP and provides status reports on actions and requirements associated with the Commission Order.

PGE does not propose modification to the acknowledged 2023 IRP Action Plan and PGE is not requesting acknowledgement of the 2023 CEP/IRP Update. We continue to find that the recommended Action Plan is in the long-term interest of our customers, providing the best path forward to ensure system reliability and continued progress toward delivering a clean, affordable energy future for Oregon.

The 2023 IRP Action Plan proposed conducting one or more RFPs to meet the Company's carbon-free energy and capacity needs through 2028. Negotiations from PGE's 2023 RFP Final Shortlist are ongoing, and PGE has requested approval of the proposed 2025 RFP. Procuring resources through these solicitations will aid PGE's ongoing efforts to demonstrate continual progress for HB 2021 and will enable PGE to address the portfolio's forecasted reliability needs.

Reliability and affordability remain the foundation of PGE's role in supporting customers and Oregon's economy. The Company's CEP/IRP demonstrates how PGE can achieve our responsibilities to deliver affordable services for our customers while maintaining progress to meet HB 2021 emissions targets.

PGE recognizes the importance of stakeholder engagement and dialogue regarding the Company's resource plans. This Update has benefited from monthly participation in PGE's IRP roundtables since the acknowledgment of the 2023 IRP. PGE looks forward to continued engagement with the Commission and stakeholders in upcoming meetings and in response to the 2023 CEP/IRP Update as filed.

Chapter 1. CEP Update

1.1 Overview

House Bill (HB) 2021 is a transformative public policy that has set Portland General Electric (PGE) on a path toward decarbonizing the power supply for Oregon retail customers.[1] PGE has engaged in robust planning, analysis, stakeholder and community engagement to inform its approach to decarbonization and to demonstrate progress toward the specific greenhouse gas (GHG) emissions targets detailed in HB 2021. Throughout the planning process, PGE remains committed to balancing affordability for customers, the reliability of the grid, and emissions reduction.

The inaugural Clean Energy Plan (CEP), filed in 2023 with the Integrated Resource Plan (IRP) was an important first step in charting a course toward emissions targets in 2030, 2035 and 2040 that balances affordability and reliability for customers. PGE has furthered this work through the continued stakeholder and community engagement and monthly roundtables that have informed this Update. PGE will continue to learn and adapt strategies as customers' needs, the market, and technologies evolve.

This chapter summarizes the results of updated modeling and portfolio analysis which form the basis of this CEP Update and details the Company's progress toward HB 2021 emissions targets.

CEP Update: Key Highlights

- PGE is not requesting Oregon Public Utility Commission acknowledgement of this Update and maintains its Commission-acknowledged Action Plan.
- PGE continues to identify a significant need to procure non-emitting resources and capacity to keep pace with new customer demands, system reliability, and to make progress toward emissions targets.
- PGE is working to continue to reduce emissions and maintaining reliable service by replacing emitting generation and market purchases with non-emitting energy and capacity resources.
- Uncertainties regarding the ability to meet emissions targets at prices that are affordable for customers on the timelines specified by HB 2021 have grown, due to factors outside PGE and its customers' control. These factors include lengthy permitting and siting processes and likely changes to federal policies including tax incentives which are anticipated to significantly increase the costs of new clean resources and tariffs that impact supply-chain availability and costs.
- Transmission is a significant factor impacting the economics and timing of resource additions. Transmission solutions are integral to maintaining reliability and providing long-term pathways for decarbonized power supply. The constraints limiting transmission expansion will drive a greater role for customer-sited

[1] House Bill (HB) 2021 codified as ORS 469A.400 to 469A.475, effective 09/25/2021.

resources such as demand response (DR), energy efficiency (EE), distributed solar/storage and community-based renewable energy (CBRE) resources, highlighting the importance of PGE's efforts to improve utilization of these resources through a virtual power plant (VPP).

- Updated analysis, based on what is currently known, finds 2030 emissions targets can be met by technologies and resources that are currently known and commercially available, though costs have increased and the timing of resource additions may be constrained based on what is commercially available in the market. While the costs presented as part of this modeling exercise do not represent actual changes to customer prices, the analysis is suggestive that, on a planning basis, system costs are likely to increase significantly in order to comply with HB 2021.
- Decarbonization pathways to 2040 will require further technological advancement of non-emitting resources and transmission to meet the region's energy and capacity needs.

PGE must continue to operate its existing portfolio efficiently and seek to procure the best combination of resources that balances costs, risks and maintains safe and reliable service for customers. As detailed in the inaugural Clean Energy Plan, decarbonizing PGE customer's power supply will require resource acquisition and integration at a significant pace and scale. The planning environment has evolved significantly since the original filing. Some of the planning changes, including changes to federal policy, resource cost increases, significant industrial load growth, and long-lead time for transmission expansion, all present challenges to the pace and affordability of PGE's path to emissions targets. Other changes to the planning environment, including progress on regional energy market development, regional resource adequacy sharing frameworks, and active state policy regarding large industrial customers and fair cost allocation provide important tools for PGE to most efficiently meet PGE customers resource needs at the lowest cost possible. External factors that affect critical dependencies are further described in **Section 1.5**.

Electricity is a critical service for local communities and the economy. Customers already rely on the utility for their essential electricity needs. Looking to the future, customer reliance on electricity will increase as they electrify their vehicles, homes and businesses. Our local industrial customers, who are advancing national interest through pursuit of advanced semi-conductor manufacturing, information technologies and artificial intelligence capabilities, need abundant and reliable service. Working to serve this industrial growth with fair cost allocation supports our local economy and has the opportunity to lower the average cost of service. Providing electrical service for all of PGE's customers with increasingly fewer emissions will require significant new investment in energy resources and distribution and transmission infrastructure to prepare for the smart, clean energy grid of the future. While PGE faces some significant changes in the planning environment, PGE's commitment to energy access, affordability, and an increasingly non-emitting electricity supply is steadfast.

PGE will continue to actively manage costs for customers throughout the transition to an energy mix while working to reduce emissions. This includes careful and inclusive planning through

PGE's Clean Energy Plan, Integrated Resource Plan, and Distribution System Plan processes, competitive procurement through Requests for Proposals (RFPs) for resources, joining the California Independent System Operator's (CAISO) Extended Day-Ahead Market (EDAM), as well as continuous efforts to improve operational efficiency, safety, and system and equipment reliability. PGE has actively pursued federal and state grant funding and tax credit opportunities to offset investment costs and support key decarbonization initiatives on behalf of customers, including infrastructure upgrades, though the future of many of those programs and grants is now in jeopardy due to the change in federal policy. PGE also supports efforts to connect customers with the unprecedented federal tax incentives and rebates available, ranging from electric vehicles to heat pumps to rooftop solar. PGE will continue to leverage available tools to prioritize affordability. Some recent examples are further described in **Section 1.4.1 Annual goals**.

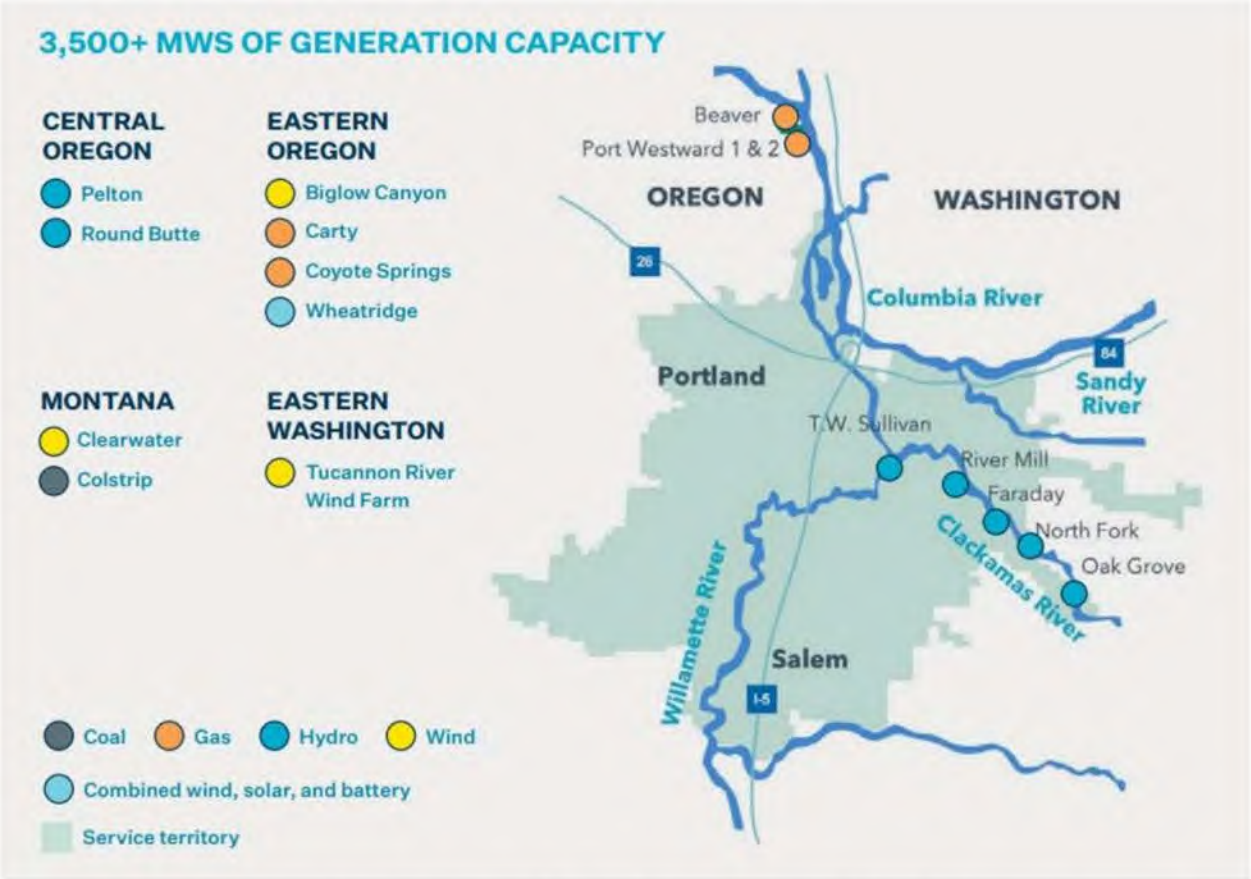
1.2 Historical emissions trends and resource mix

PGE customers include some of the world's most sophisticated corporate renewable energy buyers and local municipalities with ambitious climate action goals. Portland, Beaverton, Multnomah County, Hillsboro, Salem and many other municipalities have developed climate action plans that encourage finding new and innovative ways to reduce the carbon intensity of electricity service, while also supporting electrification efforts, fostering economic development and modernizing the grid to enhance resilience to extreme weather. Many companies in PGE's service territory have publicly adopted ambitious clean energy or emissions goals, including Oregon Health and Science University, Nike, Intel, STACK Infrastructure, Daimler and others. As large electricity buyers, they look to PGE to support their decarbonization efforts.

PGE supports customers' climate and sustainability goals by decarbonizing the electricity supply and offering innovative voluntary programs that enable customers to go further and faster. PGE offers programs for large businesses, cities and counties that match their electricity needs with new renewable energy facilities in the region. Convenient options are also available for small business and residential customers to support clean energy development by purchasing renewable energy certificates from energy generation throughout the U.S. In 2021, PGE became the first utility in North America to sign The Climate Pledge to achieve net zero emissions across company operations (Scope 1, 2 and 3 emissions) by 2040, ten years ahead of the United Nations' Paris Agreement. PGE then collaborated with state lawmakers and stakeholders to pass Oregon's 100 percent Clean Electricity Law (HB 2021) to establish emissions targets for electric utilities in Oregon.

PGE meets the growing clean energy demands of customers with a diverse mix of generation facilities shown in **Figure 1**, owned in whole or in part, or through contract. Today, PGE's generation portfolio consists of seven hydroelectric facilities, five natural gas facilities, three wind facilities, one combined wind/solar/ battery facility and a partial ownership stake in an out-of-state coal facility. PGE previously announced the acquisition of 475 MW of new battery storage projects, of which 275 MW achieved commercial operations in December 2024 with the remaining 200 MW scheduled for service in mid-2025.

Figure 1. PGE generation portfolio



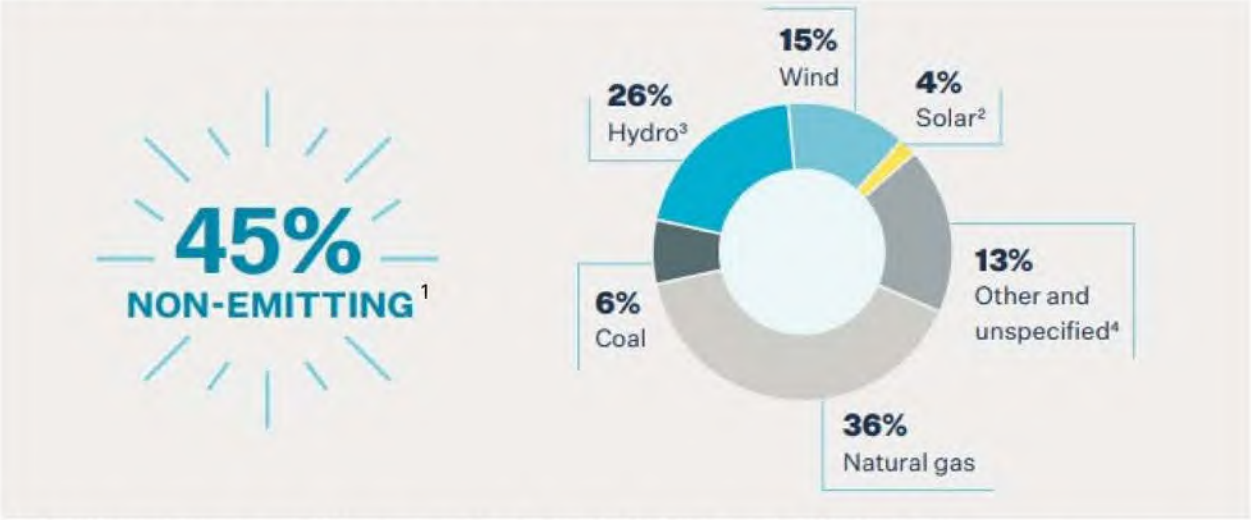
Customer-sited resources, including rooftop solar, batteries and standby generation play an increasingly critical role in the resource portfolio. For example, customer-sited rooftop solar generation contributed an additional 264,826 MWh of non-emitting energy in PGE service territory in 2024. PGE manages the output of owned power plants in conjunction with available power supplies on the wholesale market to deliver power to customers at the lowest possible price. PGE actively coordinates with transmission providers like the Bonneville Power Administration and other utilities and energy suppliers across the region, to secure transmission access and additional power on contract for customers. PGE also owns major transmission rights to the Pacific Intertie and participates in the CAISO Energy Imbalance Market (EIM) and the soon-to-be established EDAM. These options provide additional flexibility to buy and sell power and to access a more diverse and increasingly clean mix of generating resources.

In 2024, PGE made strong progress toward advancing a resource mix for total system load that is increasingly clean. The percentage of total load comprised by non-emitting resources grew from 35 percent in 2023 to 45 percent in 2024. As a result, the carbon intensity of the total power supply declined to 0.27 MMTCO2e per MWh in 2024, despite load growth. While natural gas remains the largest component of the generating mix and provides much-needed capacity to meet resource adequacy and reliability requirements – hydropower, wind and utility-scale solar continue to grow on the system, in addition to customer sited renewable energy resources like rooftop solar. Wind output alone grew by 56 percent, reaching record breaking levels of wind

generation on the system in 2024 primarily due to the addition of the Clearwater Wind facility in Montana. Not only does this facility have a high energy output rate, but it also generates power when other wind resources closer to home in Oregon and Washington are less productive. This exemplifies the importance of resource diversity in the portfolio – and is a critical decarbonization strategy.

Unspecified emissions are reported as part of annual GHG reporting to the Oregon Department of Environmental Quality (ODEQ) when the underlying source of generation for energy purchased from the market, including from CAISO's Energy Imbalance Market, is unknown or not otherwise specified in a contract. Following best practice and ODEQ rules, an emissions rate is assigned to unspecified purchases in recognition that the power pool in Western states still includes fossil fuel generation. Throughout 2024, PGE reduced emissions from unspecified sources, from 16 percent of the resource mix in 2023 to 14 percent in 2024. As Western states decarbonize and energy markets such as CAISO adopt more precise mechanisms for tracking and reporting the carbon content of resources dispatched and allocated through energy markets, emissions associated with unspecified purchases should continue to decline. **Figure 2** summarizes PGE's total system resource mix for 2024.

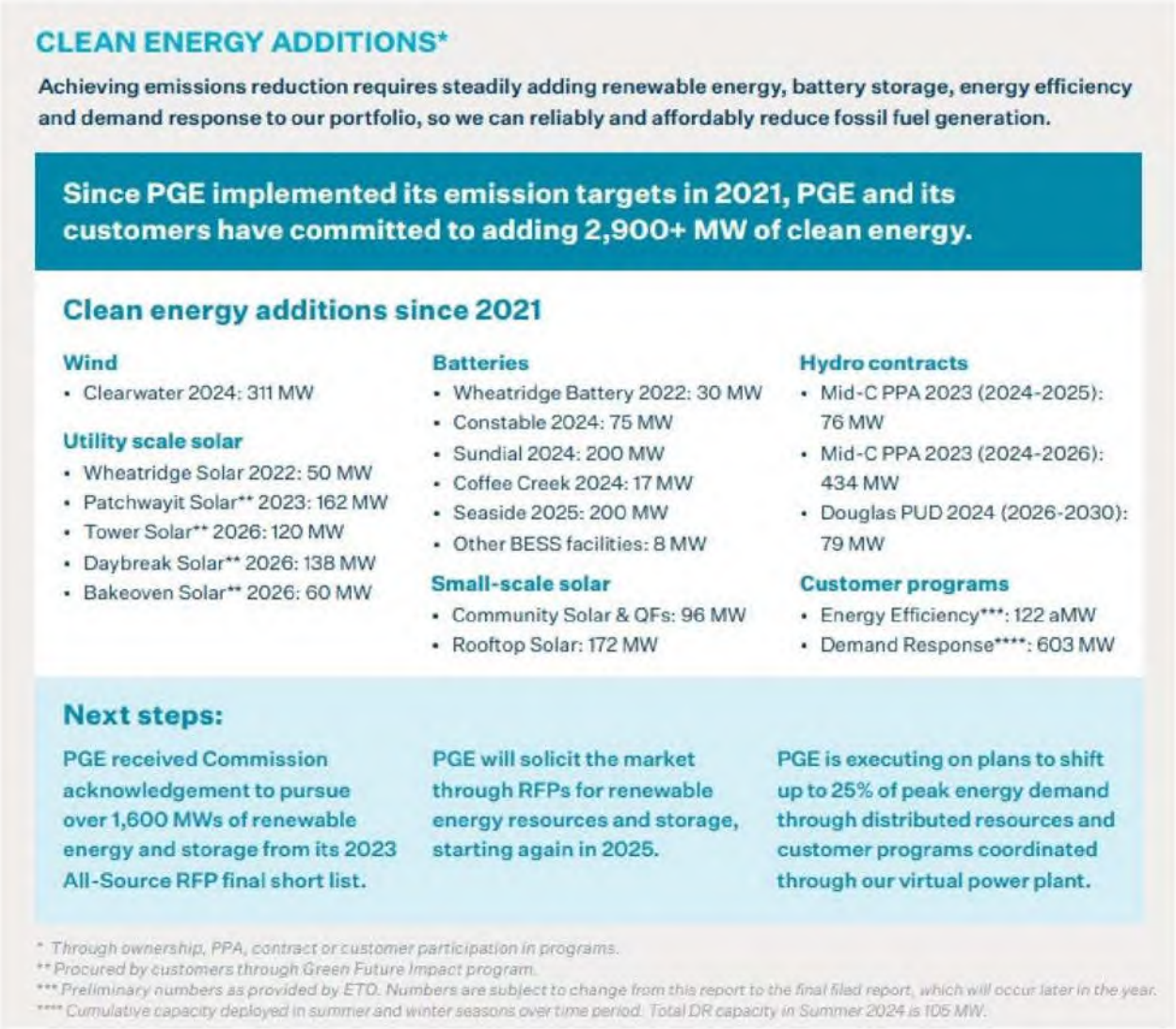
Figure 2. PGE total system resource mix



1. Percentages above represent 2024 resource mix from PGE's total load, inclusive of wholesale volumes.
2. Represents owned and contracted solar resources, does not include the 264,826 MWh of customer owned rooftop resources.
3. Hydro amounts include purchases from Bonneville Power Administration, which may have an immaterial amount of emissions associated with them, per ODEQ rules.
4. Unspecified is purchased power for which a specific generating resource is not defined and could be any of the generation types (e.g., wind, hydro, gas)

PGE recently concluded the largest open-application request for proposal (RFP) for clean energy resources to augment the portfolio to date and has applied to return to the market with another RFP in 2025. This and subsequent RFPs will be necessary to meet customers' energy needs and work towards PGE's emissions targets. PGE's steady progress in procuring clean energy and investing in grid-edge technologies and customer programs will reduce reliance on fossil fuels and drive a cleaner resource mix in the coming years. Additions since 2021 are shown in in **Figure 3**.

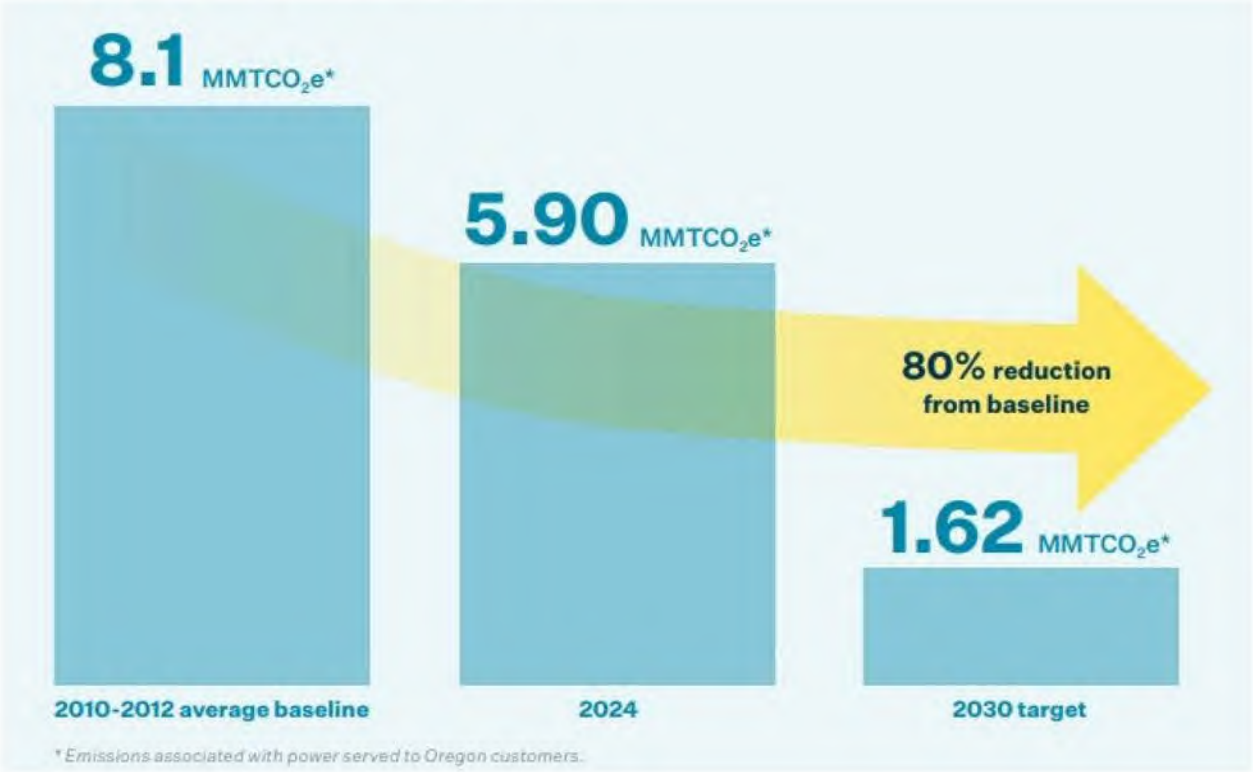
Figure 3. Clean Energy Additions



As shown in **Figure 4**, preliminary estimates subject to ODEQ final approval of emissions associated with power served to Oregon customers in 2024 equated to approximately 5.90 million metric tons of CO_2e.[2] This is a 10 percent decrease in retail emissions reported in 2023, largely driven by additional hydropower and the addition of the Clearwater Wind facility. It also represents a 27 percent reduction in baseline emissions established for HB 2021 compliance.

[2] The 2024 emissions estimate is preliminary pending reporting and third-party verification, as required by the Oregon Department of Environmental Quality (ODEQ).

Figure 4. 2024 GHG emissions in context



Like most utilities, PGE's emissions are driven by the fossil fuels combusted to generate electricity. PGE is actively planning and executing strategies for a balanced transition from thermal generation to increasingly cleaner generation sources while providing reliable energy service that can affordably meet customers' energy needs. Year-to-year variations in reported emissions may be driven by changes in economic factors that affect load or changes in weather that affect hydro conditions, renewable capacity and peak energy needs, that are increasingly hard to forecast. This is discussed further in **Section 1.4.2 GHG emissions**.

Achieving emissions reduction requires steadily adding, to the extent available, renewable energy, battery storage, energy efficiency and demand response to the portfolio to reliably and affordably reduce fossil fuel generation. Customer-sited resources, including rooftop solar, batteries and standby generation play an increasingly critical role in the overall resource portfolio as PGE decarbonizes.

In 2023, PGE published its combined Clean Energy Plan and Integrated Resource Plan, a twenty-year roadmap for meeting customer energy needs at the lowest possible costs while transitioning from fossil fuel generation. PGE demonstrated a potential path toward the 80 percent emissions reduction target in 2030 that involves resources and technologies that are economically and technically feasible in the region today. No single technology right now can replace the role of natural gas generation in the electric power system. Clean energy of all types – including customer rooftop solar generation, community-scale microgrids that combine batteries and solar, utility-scale wind, batteries – energy efficiency and demand response

programs and customer dispatchable standby generation will all be needed to replace the energy and backstop capacity that natural gas currently provides. Looking ahead to deeper decarbonization targets in 2035 and beyond, PGE anticipates the need for access to a broader geographic diversity of resources and technologies to replace fossil fuels on the grid. This will require solutions to current regional transmission constraints and adopting future non-emitting technologies as they become cost-effective. This could include green hydrogen, offshore wind, nuclear, long-duration storage and carbon capture and storage.

When the Legislature passed HB 2021 in 2021, PGE was anticipating flat to minimal load growth, consistent with trends for the electric sector across the country. Since the passage of HB 2021, PGE and the region are forecasting significant industrial load growth, led primarily by the expansion of data centers, AI technologies, and advanced manufacturing. HB 2021 targets are absolute emissions targets, not carbon intensity targets, and are unforgiving of the load growth forecasted for the region and PGE's service territory.

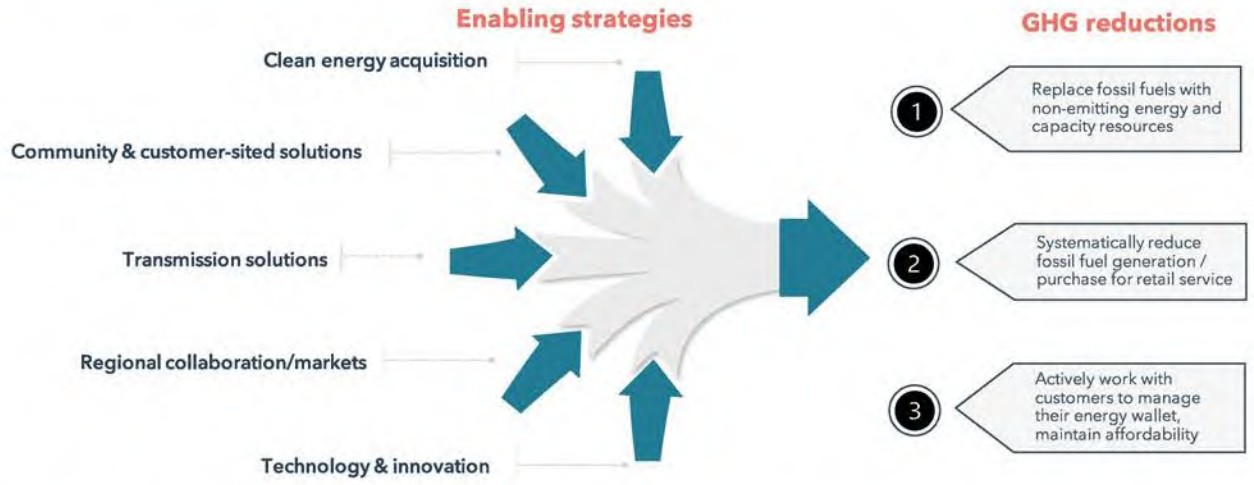
This CEP/IRP Update reflects a significant increase in need for procurement of new generation and storage capacity to keep pace with new customer demand as well as to make progress toward emissions targets. The utility is also considering ways to allocate relevant costs fairly to customers that have a high demand for electricity, such as new data centers. Mitigating residential and small commercial customer price impacts and maintaining reliability are core priorities as PGE decarbonizes its power supply while keeping all customer prices as low as possible.

PGE's decarbonization planning centers on customers' needs and investments in new non-emitting resources and the grid that make progress toward the HB 2021 emissions targets for 2030, 2035 and 2040. At the highest level, the approach to reducing emissions involves:

- Increasing purchase and integration of non-emitting energy and capacity resources.
- Systematically reducing the generation and purchase of fossil fuels for Oregon retail customer load.
- Actively working with customers to help them manage their energy use and total energy expenditures.

This approach is bolstered with key, enabling strategies to be able to deliver a reliable, affordable, clean energy supply, displayed in **Figure 5**.

Figure 5. Decarbonization strategies



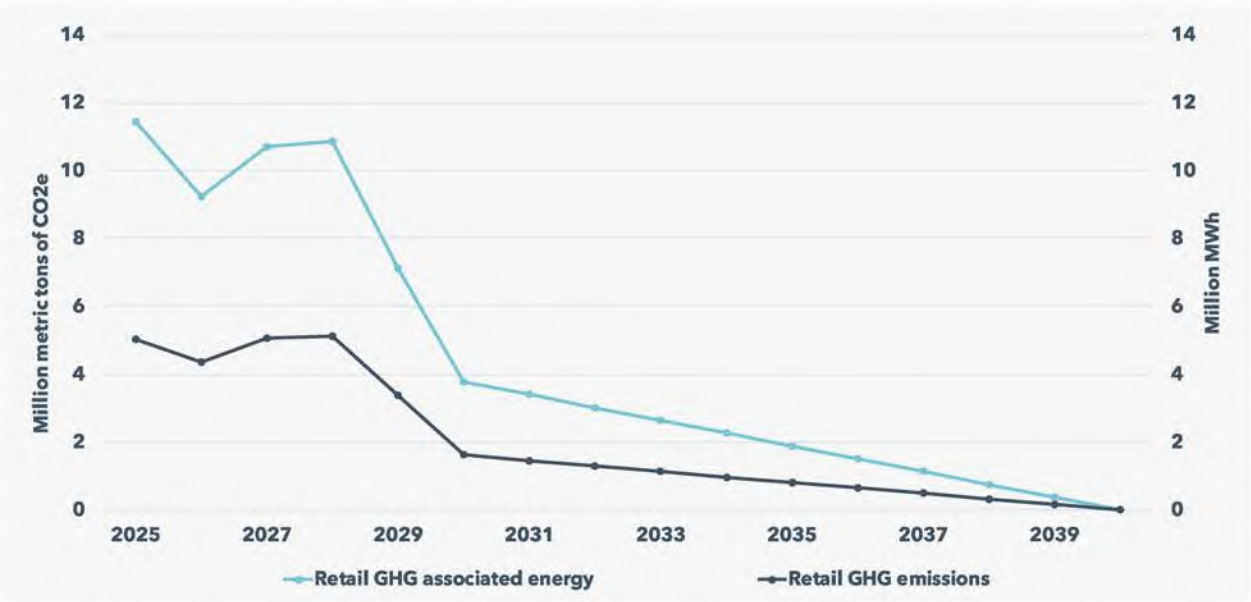
This high-level approach to decarbonization involves gradually reducing fossil fuel generation and purchases for Oregon retail customers and replacing it with non-emitting energy resources and capacity, as well as key enabling strategies to facilitate a reliable and affordable transition. The IRP estimates PGE's energy and capacity needs subject to HB 2021 emissions constraints. It creates a Preferred Portfolio of resources to meet those needs and details an Action Plan to guide the company's procurement and related resource actions over the next 2-4 years.

1.3 Pathways to emissions targets

One of the CEP's primary objectives is to detail a path to compliance with the HB 2021 targets. It shows that the Preferred Portfolio and Action Plan that PGE has developed in its IRP are consistent with steps the company could take in the near-term to make progress toward the emissions targets in 2030, 2035 and 2040, according to the best methods available at the time of analysis. Moreover, the CEP describes how the company will demonstrate continual progress toward those targets. This section summarizes how strategies to decarbonize, resource needs and the Action Plan inform a path to the emissions targets that balance affordability and reliability for customers.

Updated data and analysis described in **Section 3.5.1 HB 2021** result in an updated emission reduction glidepath also presented here in **Figure 6**.

Figure 6. GHG emissions and energy associated with serving Oregon retail load (Reference Case)



PGE's glidepath identifies expected thermal generation and market purchases with associated emissions retained for retail load. Since the 2023 CEP/IRP, PGE has updated the earliest available resource addition year to 2029. This means that while PGE continues to add customer sited non-emitting resources like distributed solar in every year, large utility scale projects are assumed unavailable for addition until the beginning of 2029 due to the considerable time required to procure and construct such resources. One important exception is the assumed addition of solar and storage resources that PGE is working to acquire through the 2023 RFP. While 2023 RFP procurement is not yet finalized, PGE forecasts for this CEP proxy resources shown in **Table 1**, added to the portfolio on January 1, 2028. This is further described in **Chapter 5 Resource options** and **Chapter 6 Resource plan**.

PGE is planning for accelerated procurement through RFPs between now and 2030. PGE has initiated the regulatory process in 2025 to conduct an RFP, which is expected to continue to seek non-emitting resources to meet needs that remain after the 2023 RFP process has concluded. PGE aims to issue this 2025 RFP to market over the summer, with negotiations likely in winter 2026 and possible resource online dates from 2029 to 2032. However, actual procurement from this 2025 RFP is yet unknown and therefore not included in this analysis.

Additional programs are offered by PGE to acquire clean energy outside the RFP processes. For example, the Green Future Impact program enables interested businesses and cities to drive procurement of new renewable energy facilities to directly support their load needs.

Progress toward the HB 2021 emissions targets will require investment and be driven by integrating additional non-emitting resources into PGE's system. The Preferred Portfolio represents the best set of incremental resource additions that balance cost and risk for customers while making progress toward HB 2021 emissions targets. External factors will challenge the pace and scale of PGE's transformation, but ultimately, resource acquisition can

enable the replacement fossil fuel generation and purchases with non-emitting alternatives to support emissions reductions toward HB 2021 targets. Beyond achieving emissions reductions, new large loads, reliability needs, and broader economic trends also impact costs.

PGE seeks to acquire and integrate non-emitting resources, resulting in declining reported emissions associated with serving retail load, under average weather and other conditions. The realities of market procurement, transmission and system integration may lead to step-changes in resources becoming available to PGE customers, resulting in non-linear emissions reductions into the future toward the HB 2021 targets. Work to further develop the virtual power plant (VPP) to enhance utilization of distributed energy resources (DERs) and community-based renewable energy (CBRE) resources will also continue in parallel over this time frame.

Figure 7 details the incremental resource actions by year between now and 2035. The figure also includes PGE's existing portfolio of resources, including proxy assumptions for the 2023 RFP (actual procurement not yet known), and declining GHG-emitting energy retained to serve retail load.

Figure 7. Preferred Portfolio resource pathway through 2035

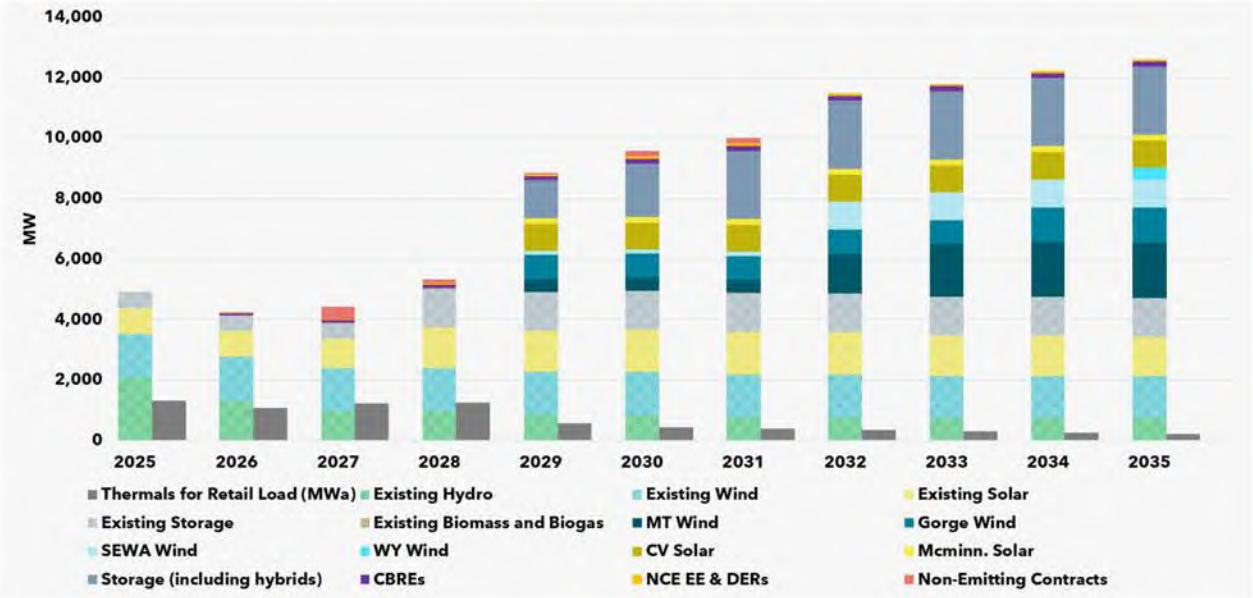


Figure 8 shows the Preferred Portfolio incremental resource additions through 2030 along with changes to PGE's existing portfolio of resources for a view of total generating capacity. The capacity of existing thermals shown in **Figure 8** does not reflect emissions target-driven reductions in emitting energy retained for retail load. After accounting for changes (reductions) to the existing mix, total capacity in the portfolio grows by roughly 1.5x in these five years to add sufficient capacity to maintain resource adequacy in light of forecasted load growth with a focus on clean energy to also meet the 2030 HB 2021 emissions target. Most of these resources are added in the model in 2029, as shown in **Figure 7** and **Table 1**, though external factors such as transmission access and RFP procurement processes and associated timelines continue to be significant factors impacting the economics and timing of actual changes to PGE's system.

Figure 8. Total resource changes from 2025 to 2030

Table 1 provides a summary of total resource actions from 2025 through 2030 as cumulative buildout within this timeframe. The analysis demonstrates the ability to meet the 2030 target using resources that are currently known and have been commercially available. Between now and 2030, PGE's thermal fleet is assumed to dispatch economically, as it does presently, to meet resource adequacy and cost-minimization for PGE's customers and the region.

Table 1. Cumulative resource buildout of the Preferred Portfolio 2026-2030 (MW)

Resource	2026	2027	2028	2029	2030
Wind	0	0	0	1362	1362
Solar (including hybrids)	0	0	0	1089	1089
Storage (including hybrids)	0	0	0	1250	1750
CBREs	66	85	110	133	155
NCE EE (MWa)	0	21	38	58	68
NCE DERs	3	8	12	13	15
Transmission	0	0	0	0	0
Non-Emitting Contracts	16	422	120	33	190
Cost-effective EE (MWa)	104	138	173	208	245
Cost-effective DR	142	172	199	225	248
2023 RFP Proxy Solar (incl. hybrids)	0	0	375	375	375
2023 RFP Proxy Storage (incl. hybrids)	0	0	775	775	775

As PGE adds non-emitting energy and capacity resources, it anticipates systematically reducing the amount of thermal output from natural gas and coal for Oregon retail load to meet emissions targets (see **Figure 27**).

The market for thermal generation is increasingly constrained across the West, with clean energy or GHG requirements in place in almost every state in the Western Interconnect. Thermal generation sold into the Western Interconnect may be subject to the GHG or clean energy requirements of other states. For example, fossil fuel energy exported to California and Washington incurs direct carbon pricing obligations. Public policies such as these, and the massive buildout of non-emitting resources anticipated across the region, lowers economically dispatched thermal output in forward modeling post-2030.

Two key planning needs become apparent when looking beyond 2030 to the 90 percent emissions reduction requirement in 2035 and the zero-emission requirement by 2040. First, there is a need for additional dispatchable non-emitting resources to be developed and available to us in the region to meet resource adequacy needs. In this analysis, the model leverages transmission to access proxy non-emitting resources from around the West to meet reliability needs that increase after 2030 (see **Table 30**). Second, part of the capacity needs leading into 2040 could potentially be offset by existing thermal plants if they were to transition to non-emitting fuels or carbon capture by 2040. It is possible that if supplies become commercially available sooner, PGE's thermal fleet could combust hydrogen or an alternative low-carbon fuel sooner. Almost all of PGE's existing thermal fleet is capable of combusting a blend of hydrogen or renewable natural gas. Informed by least-cost and least-risk planning, the current Preferred Portfolio relies on new non-emitting resources rather than changes at existing thermal plants to reduce emissions.

As described in **Chapter 6 Resource plan**, IRP portfolio analysis determines the best combinations of resource technologies and quantities to meet energy and capacity needs under different scenarios. This informs the creation of the Preferred Portfolio, the company's Action Plan, and a path to HB 2021 emissions targets. The insights gleaned from the construction and comparison of different portfolios informed the creation of PGE's Preferred Portfolio and a balanced path to HB 2021 emissions targets, specifically finding that:

- On a planning basis, system costs are likely to increase in order to reliably meet load growth as well as to comply with HB 2021.
- External factors such as federal policy changes, transmission access, and RFP procurement processes and associated timelines continue to be significant factors impacting the economics and timing of non-emitting resource additions to PGE's system.
- Regional coordination is important for managing costs, as indicated by the portfolio sensitivity analyses focused on resource adequacy and non-emitting market purchases.

PGE's 2023 CEP/IRP Action Plan remains robust, and therefore, PGE is not requesting modifications or seeking acknowledgment of this Update. Updated analysis described throughout this report suggests resource need has increased, driven mainly by growing demand and the need to maintain resource adequacy. The Action Plan referenced in **Chapter 7** remains the best set of near-term resource options for the company to consider in reliably building towards HB 2021's emissions targets while minimizing costs. With uncertainties in the planning

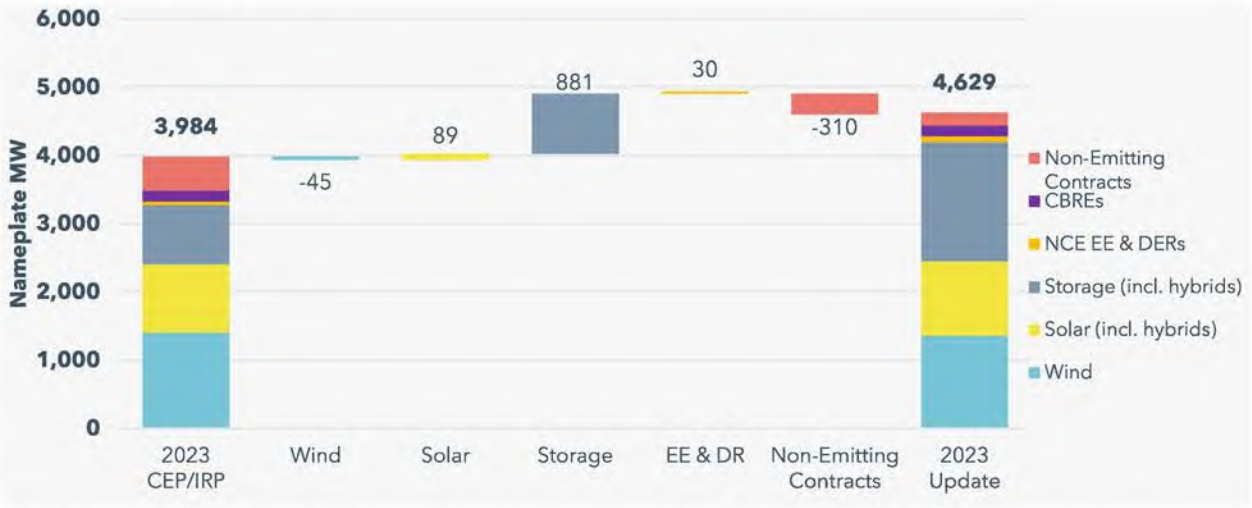
environment, rapidly changing policy landscape, and results of current and future procurement processes, the Action Plan will be reviewed and refined in the 2026 IRP.

1.4 Progress in the CEP Update

This Update includes a range of model assumption refinements aimed at refreshing PGE's planning analytics and incorporating feedback and staff direction from LC 80 Order 24-096. Some key refinements to analysis include changes to supply-side resource costs and options, electricity price forecast, capacity contribution values, and significant developments in transmission planning.

These changes lead to important implications for resource planning further described in this report. For example, updated resource economic assumptions show significantly higher prices in some years, affecting the evaluation and selection of resources in portfolio analysis. The reduced capacity contribution of storage resources (particularly in winter) highlights a critical planning challenge regarding the interaction between storage and energy resources in a system with growing demand and thus energy deficits. Refinements to transmission options included in modeling now reflect more realistic estimates of project timelines, achievable capacity, and market access benefits. These changes highlight the growing urgency of PGE's transmission needs as the company works toward decarbonization goals while facing anticipated increasing load growth and system constraints. **Figure 9** compares the resource additions in the updated Preferred Portfolio to data presented in the 2023 CEP/IRP for model year 2030. Growing demand and updates to supply-side resource costs are main drivers in the differences of model additions, which is broken out by resource type.

Figure 9. Cumulative resource additions through 2030 in the updated Preferred Portfolio compared to 2023 CEP/IRP



As the forward-looking planning environment evolves, PGE is still able to demonstrate measurable impacts and progress across the same metrics that were presented in the 2023

CEP.[3] PGE will measure progress toward HB 2021 emissions targets in a variety of ways, such as in megawatts of non-emitting resources added to the system, in addition to tons of emissions reductions. Measuring progress with multiple metrics is important for two key reasons. First, emissions reductions are predicated on adding non-emitting resources and capacity to reduce thermal generation and purchases for meeting load and resource adequacy requirements. Second, emissions associated with retail sales reported to ODEQ between now and 2030 will exhibit year-to year variation, due to factors like weather that impacts hydro conditions, renewable capacity and peak loads or other events that the utility could not reasonably forecast or control.

1.4.1 Annual goals

HB 2021 does not explicitly set GHG limits for years prior to 2030. ORS 469A.415 (4)(e) states that electric utilities, like PGE, must demonstrate continual progress towards meeting clean energy targets in a Clean Energy Plan (CEP). HB 2021 did not define progress as actual annual emissions reductions. PGE interprets this progress as planned actions to gradually replace fossil fuel resources with non-emitting ones, aiming to meet the 2030, 2035, and 2040 emissions targets. Concurrently with the IRP Action Plan, PGE's decarbonization strategy is multi-faceted to support reliable and affordable power through clean energy procurement, customer-sited solutions, technology and innovation, and regional solutions to resource adequacy.

Since the 2023 CEP/IRP, PGE has continued to make progress in acquiring clean energy resources and investing in advanced grid technologies and customer programs to reduce reliance on fossil fuels and meet future emissions targets.

On customer programs, 122 MWa have been saved from energy efficiency measures since 2021. Demand response capacity totaled 105 MW in 2024. Customer actions reduced record load by more than 90 MW at the hottest time of the day during an August 2023 heat wave, avoiding outages and increasingly volatile power market purchases during extreme weather events. PGE is executing on plans to shift up to 25 percent of peak energy demand through resources including distributed resources and customer programs coordinated through the virtual power plant. Additionally, customer-sited rooftop solar additions increased in 2023 and 2024.

Importantly, PGE is conducting a request for offers (RFO) for CBRE resources, informed by engagement with and input from community representatives, PGE's CBIAG, potential bidders, and Oregon Public Utility Commission (OPUC) Staff. Since CBRE is a new type of resource acquisition, PGE has been providing information and exploring appropriate regulatory treatment through regular updates to OPUC Staff. The RFO is open through November, with three rounds of evaluation. More details and results anticipated in 2026.

PGE has also expanded utility-scale clean energy and capacity resources. In part due to the 2021 RFP, PGE expanded the resource and geographic diversity of the non-emitting resource portfolio

[3] In the Matter of Public Utility Commission of Oregon, House Bill 2021 Investigation into Clean Energy Plans, Docket No. UM 2225, Order No. 22-390 (Oct 25, 2022), Attachment #1 at Topic #8, available at https://apps.puc.state.or.us/orders/2022ords/22-390.pdf.

when the 311 MW Clearwater Wind facility in Montana began generating test energy in 2023, coming fully online in early 2024. PGE procured 492 MW of new battery storage in 2024, the largest acquisition by a utility outside of California, including the 75 MW Constable Battery Energy Storage System. PGE also executed, renewed and extended three cooperative agreements for hydropower from regional public utility districts, included here as part of the baseline portfolio. In November 2024, the OPUC acknowledged the shortlist of projects from a 2023 RFP that was filed shortly after the 2023 CEP.[4] PGE ranked the final shortlist of up to 1,600 MWs of renewable energy into two groups, prioritized based on performance in the scoring evaluation, representing the optimal intersection of value to customers at least-cost and least-risk. A follow-on RFP has been initiated in 2025 to continue to address needs.

PGE continues to investigate transmission actions, a critical need to meet growing demand, maintain system reliability, and further support decarbonization while balancing costs and risks. In late 2023, PGE and the Confederated Tribes of Warm Springs (CTWS) received a $250 million grant from the U.S. Department of Energy (DOE) to enhance the Bethel-Round Butte line and support imported power. PGE broadly continues to leverage federal, state, and local funds to support clean energy and efficiency initiatives. For example, PGE is currently working with the City of Portland and $40,000 in grant funding for installing electric vehicle chargers. Other avenues to help lower costs and increase system reliability are also moving forward. In 2024, PGE announced its intent to join the California Independent System Operator's (CAISO) Extended Day-Ahead Market (EDAM), expected to begin operations in 2026. Participation will provide access to more clean energy resources from across the West.

PGE's 2024 Environmental, Social and Governance Report shares further information about the company's commitment to sustainability along with information about strategic projects that illustrate progress in advancing a sustainable future and commitment to the community. To read the full 2024 Report, "Advancing Toward a Clean Energy Future," visit www.portlandgeneral.com/sustainability.

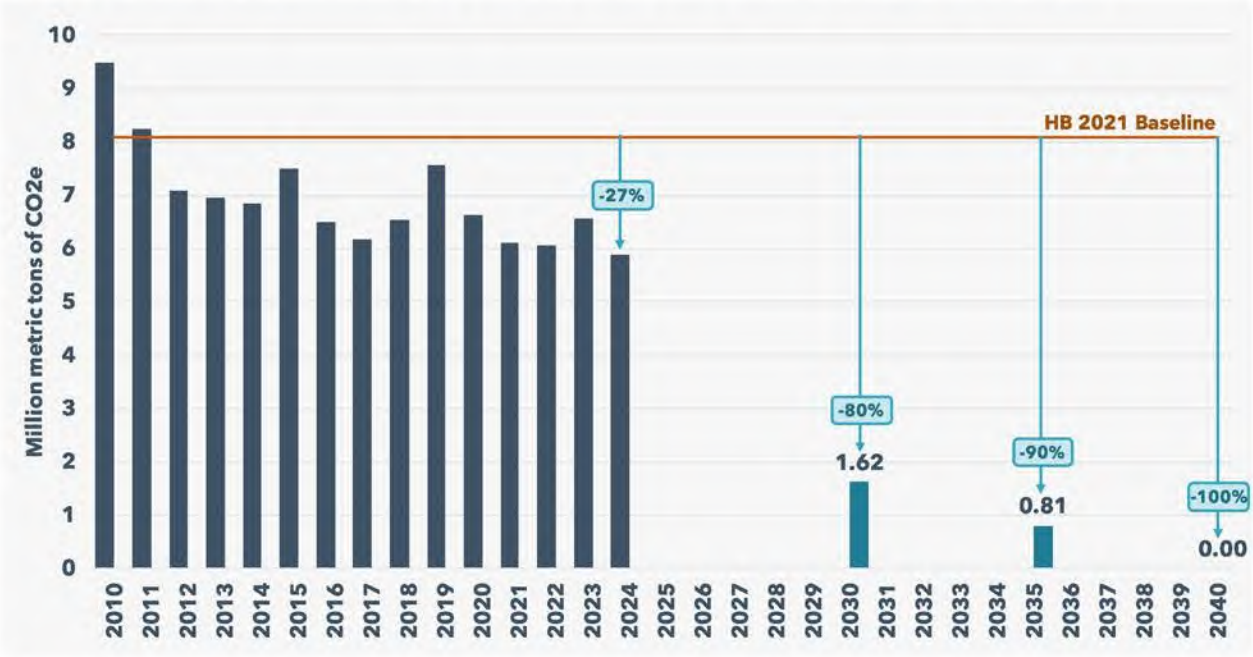
To examine the optimal progress toward the 2030 emissions target in portfolio analysis, PGE analyzed various GHG glidepaths in the 2023 CEP/IRP. Ultimately, the Preferred Portfolio that informed the Action Plan was constructed in a way that minimized the costs and risk of new resource acquisitions and maximized the provision of community benefits by thoroughly investigating key decision points with the potential to impact costs. This included selecting a linear GHG-emissions reduction pathway that met HB 2021 requirements while mitigating costs relative to more aggressive pathways and reducing risks compared to less-aggressive pathways. Choices that minimize cost or risk were also made regarding additional DERs, the inclusion of CBRE resources and opportunities to expand transmission availability. For more information, see Chapter 11 Portfolio analysis in the 2023 CEP/IRP.

[4] In the Matter of Public Utility Commission of Oregon, PGE Request for Waiver of 2023 RFP Process, Docket No. UM 2274, Order No. 24-425 (Nov 25, 2024), available at https://apps.puc.state.or.us/orders/2024ords/24-425.pdf.

1.4.2 GHG emissions

GHG emissions from generation and power purchases fluctuate year to year, often due to variations in economic conditions, temperature, wind/solar conditions, water conditions and other external factors. For example, higher-than-expected temperatures can increase the need for mechanical cooling (air conditioning), which increases demand and the emissions associated with serving that retail electrical load.[5] Water conditions can change hydroelectric power availability, with low water years, such as 2023, increasing reliance on GHG emitting generation. An increase or decrease in macroeconomic activity can alter energy demand and the emissions associated with serving retail load. **Figure 10** demonstrates the variability of year-to-year reported emissions, with a declining trend from 2010 through 2024.

Figure 10. Historical emissions for Oregon retail load service and HB 2021 targets



Due to these annual GHG variations, the OPUC has stated that utilities should "achieve the 2030 and 2035 clean energy targets under typical or expected weather and hydro conditions…".[6] This implies that emissions may be higher or lower than the targets due to variability, but under average conditions meet the targets.

The IRP assumes future load growth after cost-effective energy efficiency and distributed energy resources (DERs) are acquired and incorporated into PGE's system. Therefore, emissions reductions occur due to non-emitting resource procurement displacing coal or gas generation

[5] Since non-emitting resources dispatch first, an increase in load above the expected basis would likely be met by gas, coal or market purchases.

[6] In the Matter of Public Utility Commission of Oregon, House Bill 2021 Investigation into Clean Energy Plans, Docket No. UM 2225, Order No. 22-446 (Nov 14, 2022), Appendix A at 31, available at https://apps.puc.state.or.us/orders/2022ords/22-446.pdf.

(as opposed to reductions from net demand reduction). In actual reporting, the non-linear historical GHG decline seen in **Figure 10** is due to various factors, including but not limited to:

- Weather variations: for example, the same power system will produce different emission levels in a mild temperature year vs. an extreme temperature year, such as 2023.
- Procurement timelines: GHG emissions decline when PGE acquires additional non-emitting energy. These acquisitions will occur in blocks and may lead to staircase-like GHG reductions over time. However, while each portion of resource procurement may lead to a 'blocky' reduction of GHG emissions, from a portfolio perspective, balancing regulatory, operational, financial and resource procurement risks points to the advantages of continual acquisition of non-emitting resources over time. Achieving continual emissions reductions will necessitate procurement of non-emitting resources throughout the decade, which is likely to provide the best opportunity to add resources that offer an optimal combination of geographic location, resource characteristics, technological advancements and access to needed transmission rights.
- Unexpected economic conditions impacting loads: higher or lower than expected load may impact GHG emissions. Higher loads could arrive from faster-than-expected industrial growth (potentially from large data centers) and/or faster-than-expected electrification.

ORS 469A.420(4)(a) requires PGE to provide the OPUC with its two most recent annual emissions reports that have been filed with the Oregon Department of Environmental Quality (ODEQ) reflecting emissions associated with retail sales. Information from these reports for years 2022 and 2023 as well as reports going back to 2010 is available on ODEQ's website[7] and is shown in **Figure 10**. At the close of 2022, PGE disclosed emissions of 6.0 million metric tons of CO_2e, a 25 percent reduction in baseline emissions from power served to Oregon retail customers. Emissions associated with power served to Oregon retail customers in 2023 equated to approximately 6.6 million metric tons of CO_2e. This is an increase from the amount reported in 2022, largely driven by the low hydropower and wind output seen throughout the region and in PGE's service territory. Throughout 2023, PGE reduced emissions from unspecified sources, which represented roughly 17 percent of the retail resource mix in 2023, compared to 21 percent in 2022. Data for 2024 show further emissions decreases to 5.9 million metric tons of CO_2e.

For the CEP Update, PGE is required to compare any GHG emissions reports filed with ODEQ since the CEP with the emissions forecast in the CEP.[8] Reported emissions for 2023 and 2024 are roughly 11 percent higher than those forecasted for retail sales for those same years in the 2023 CEP/IRP. The retail sales emissions forecast for planning assumes average conditions. As described above, actual weather and temperature conditions for these years were considered to

[7] ODEQ, Greenhouse Gas Emissions Reported to DEQ, available at: https://www.oregon.gov/deq/ghgp/Pages/GHG-Emissions.aspx.

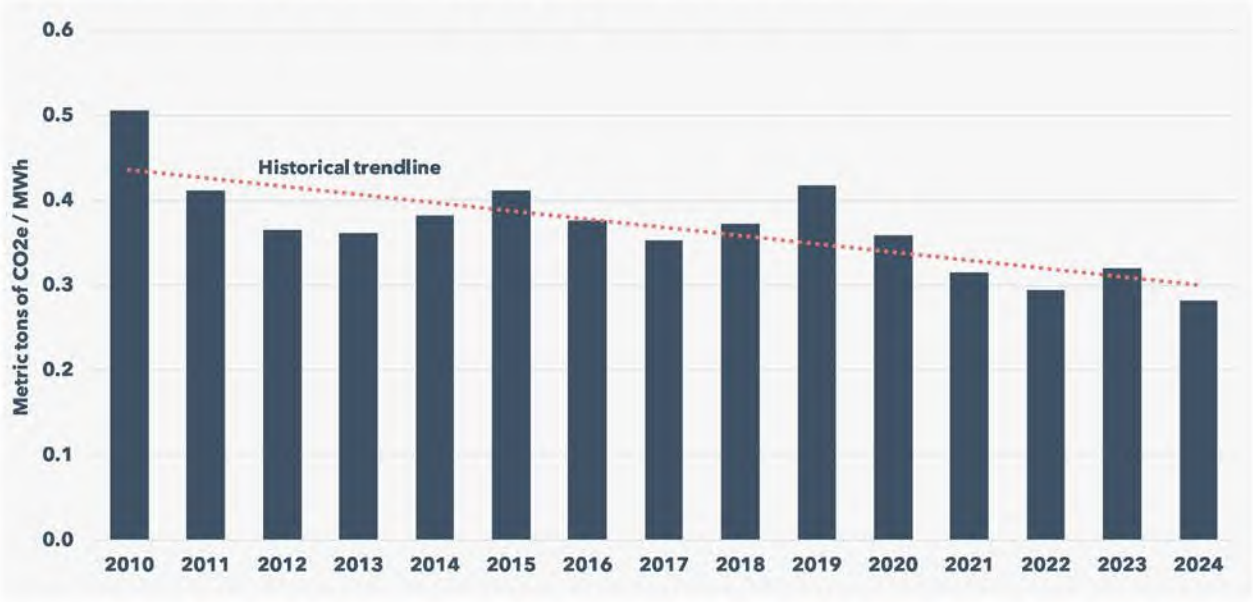
[8] In the Matter of Public Utility Commission of Oregon, House Bill 2021 Investigation into Clean Energy Plans, Docket No. UM 2225, Order No. 22-390 (Oct 25, 2022), Attachment #1 at Topic #8, available at https://apps.puc.state.or.us/orders/2022ords/22-390.pdf.

be above average, resulting in greater reliance on emitting resources than was forecast. Relatedly, HB 2021 does not explicitly set GHG limits for years other than the target years of 2030, 2035 and 2040. ORS 469A.415 (4)(e) states that electric utilities, like PGE, must demonstrate continual progress towards meeting clean energy targets in a CEP. HB 2021 did not define progress as actual annual emissions reductions. However, PGE has been making progress toward decarbonization and 2024 emissions are 27 percent below HB 2021's 2010-2012 average baseline level of emissions.

1.4.3 GHG emissions intensity

Because of the correlation between retail load and emissions, GHG emissions intensity, defined as metric tons of CO_2e per megawatt hour (MWh), is a useful decarbonization metric as it normalizes changes in load to better account for the resource mix that is serving that load. **Figure 11** shows PGE's Oregon retail GHG intensity from year 2010 through 2024. In 2024, PGE made strong progress toward advancing a resource mix that is increasingly clean, resulting in a decline in the carbon intensity of the retail power supply despite anticipated load growth. While GHG intensity provides useful information, HB 2021 requires an absolute reduction in utility GHG emissions, not a decrease in GHG intensity.

Figure 11. Historical GHG intensity for Oregon retail load service



1.4.4 Average electric rates for Oregon customers

HB 2021 does not set requirements relating to electricity rates nor does PGE present information on rates in the CEP or IRP due to the disconnect from this forward-looking planning document from actual rates, which are based on real investment decisions. Some $/MWh prices aligning with total costs represented in the IRP are included in **Section 6.2.1 Yearly cost estimates**. These yearly price impacts do not represent actual customer rates as they only focus on planned

generation and transmission expansion cost changes and do not incorporate any other cost changes across PGE. The metric can still be indicative for evaluating options to decarbonize.

1.4.5 Community impacts and benefits

PGE has supported Oregon communities with reliable, affordable and safe power for over 130 years. While many things have changed over that time, PGE's core responsibility to power Oregon homes and businesses has not. It has become increasingly apparent that climate change poses significant risks to the electric sector across all regions of the country. Extreme weather and natural disasters threaten utility infrastructure, contribute to energy market volatility and render the balancing of energy supply and demand more challenging. Climate change has been witnessed first-hand at PGE in the form of record-breaking winter and summer energy peaks, damaging and disruptive storms, and increasing wildfire risk.

PGE's commitment to equity is important across all areas of the business, but especially when it comes to the disproportionate impacts of climate change on vulnerable communities. PGE aims to decarbonize the system in ways that can benefit communities disproportionately impacted by climate change, as required by HB 2021. In the 2023 CEP/IRP, Chapter 7 (Community benefits indicators (CBIs) and community-based renewable energy) described efforts to apply an equity lens to resource and decarbonization planning. Chapter 14 Community equity lens described efforts throughout PGE's planning process to create an inclusive process in which all communities served can participate and be heard.

For the 2023 CEP/IRP, PGE conducted a CBRE potential study and incorporated the results into portfolio analysis to assess the contributions of these resources toward meeting the system requirements and providing community benefits.[9] CBRE resource potential and associated CBIs are included in portfolio analysis to understand the implications that their relative costs, system benefits and CBIs have on various metrics considered within the planning framework and across various portfolio options. In 2024, PGE engaged Resource Innovations (formerly Cadeo) to conduct research into CBIs. Based on this research and stakeholder feedback, PGE refined its approach to how CBIs are considered in analysis as well as expanded the list of CBIs which is further discussed in **Section 5.5 Community benefits indicators (CBIs)**.

Integration of CBIs provides an opportunity for PGE to extend resource planning to include the values and priorities of the communities PGE serves. CBIs have evolved into an analytical framework for addressing resilience, equity, environmental impact, public health, and economic development, ensuring that resource planning considers benefits that are tangible, measurable, and equitable.

By analyzing CBIs within the IRP, PGE can account for community benefits in quantifiable ways to inform resource portfolio decisions. Proxy metrics are used for CBIs that are difficult to quantify, monetize, or lack sufficient data. Outside the IRP analysis, informational CBIs provide a critical

[9] Incorporating CBIs and CBREs into PGE's overall portfolio planning process was described in the 2023 CEP/IRP Chapter 11, Portfolio analysis. The approach to CBI development, including informational CBIs not included in IRP portfolio analysis, was described in Section 7.1, Community benefits indicators.

mechanism for establishing baselines and tracking progress toward achievement of other CBIs based on program delivery and performance.

The challenges identified–including data gaps, proxy metric limitations, and diverse stakeholder priorities–highlight the need for continued research, collaboration, and refinement. Through expanded and continued stakeholder engagement, localized data development, and the adoption of advanced methodologies, PGE is well-positioned to continue to address these challenges and further enhance the impact of CBIs.

1.5 High-level opportunities, potential barriers, critical dependencies

PGE's critical barriers to long-term decarbonization efforts are the same as those faced throughout the industry and global economy. Major barriers include the pace of development for commercially available non-emitting generation technologies, the availability of transmission to access renewable resources, affordability constraints, supply chain disruptions, and permitting and regional interconnection limitations. Solutions will depend on regional cooperation between utilities and jurisdictions, federal policy and financial support.

Current uncertainties in the future of federal policies, tariffs, and supportive tax incentives for renewable energy will meaningfully impact the affordability of PGE's clean energy transition. Further, tariffs on imported goods can impact materials supply chains, slowing timelines and increasing costs of new clean resource buildout. There is much uncertainty about the anticipated cost impacts of final tariffs on solar and energy storage components imported into the United States, but it is likely that the cost of power and energy storage will rise. Procurement delays, supply chain constraints, increased uncertainties in available transmission inventory, siting challenges and operational risks associated with adding large quantities of resources in a short period of time can also delay PGE's timeline.

PGE faces additional procurement challenges related to unresolved exposure to wildfire risk. To achieve the resource procurement targets related to HB 2021, and our customer's reliability needs, PGE must procure multiple gigawatts of new clean resources. The capital investments necessary to construct and commission such resources are significant. Wildfire risk is growing in Oregon, threatening the safety of the communities we serve, as well as utility assets and the overall financial health of the utility. This risk is reflected in higher capital costs, which drive up the costs of clean energy projects. While PGE anticipates working with Independent Power Producers under multiple commercial structures (e.g., Power Purchase Agreements), PGE will likely face barriers to secure low-cost contracts given the perceived risk of utility financial losses related to wildfire. This challenge is not easily resolved; despite successfully accomplishing robust wildfire mitigation that protects human safety, business partners are forced to increase prices to recognize the unresolved financial exposure that PGE presents as counterparty.

Any significant change in statutes, rules or guidelines that would require PGE to alter its strategy or restrict optionality in the pursuit of non-emitting resources could delay emissions reductions or threaten reliability and affordability for customers. Relatedly, load growth forecasts continue to increase, further impacting PGE's ability to swiftly decarbonize given existing technologies, costs, and the imperative to maintain a reliably system.

PGE will be ready to continue to adapt strategies accordingly and will continue to engage regulators, stakeholders, and communities in the next full CEP/IRP. This engagement will be in part informed by forthcoming Commission direction in UM 2273 on the planning requirements relating to HB 2021's cost cap provisions. Moreover, in light of many changes to the federal policy landscape, the broader macroeconomic environment, Oregon's economy, and unanticipated load growth that is outpacing the integration of renewables and storage technologies, it is likely that policy makers and stakeholder will initiate discussions soon on the appropriateness of Oregon's clean energy policies and whether changes or additional supports are necessary. There will be critical junctures on the way to 2030, 2035 and 2040 emissions targets that may require material changes in decarbonization pathways analyses. Resource needs for reliability and the pace of acquisition of non-emitting energy and capacity will be tracked closely and if PGE has concerns around maintaining reliable operations or if there are delays beyond the utility's control, adjustments to the implementation approach will be needed to overcome timeline, affordability, reliability, or other constraints. At the same time, if new technologies or transmission options on- and off-system do not materialize, PGE will likely not be able to access the diverse resources the system needs to decarbonize and maintain reliability. Successful solutions depend on regional coordination and cooperation, as well as on federal, state, or local tax credits and other support for siting and permitting resources and evolving grid strategies.

To execute on a long-term plan, the quantities of non-emitting resources estimated to be available on the market need to be actualized as well as cost-effective. New transmission is needed to gain access to off-system resources or reliability of the system is at risk. Nearer the 2040 target and an absolute zero emissions requirement, new technologies that can replicate thermal generation dispatchable capacity, such as advanced nuclear, hydrogen or carbon capture and storage will be needed across the region to support decarbonization and resource adequacy.

1.6 Acknowledged Actions, Order requirements and other updates

Along with the CEP updates provided in **Section 1.4**, the Update addresses Actions and Requirements that were stipulated in the OPUC's Acknowledgement Order, Order 24-096.[10] This section provides a summary of how the Actions and Requirements were addressed and where that information can be found in this Update. The information and analysis that has been updated from the 2023 CEP/IRP is also summarized as well as those which remain unchanged in this filing.

Table 2 provides a summary of the Actions and Requirements and the location where additional details can be found.

[10] In the Matter of Public Utility Commission of Oregon, PGE 2023 CEP and IRP, Docket No. LC 80, Order No. 24-096 (Apr 18, 2024), pp.18-22 and Appendix A, Attachment 1, pp.26-27, available at https://apps.puc.state.or.us/orders/2024ords/24-096.pdf.

Table 2. Actions and Requirements crosswalk

Action/Requirement	Applicable Section(s)
A. Conditions and Direction Related to PGE's Action Plan	
Staff Recommendation 1: CBRE Actions	Acquisition of CBREs is discussed in **Section 7.1.2.** Additional information regarding PGE's CBRE activities is available on PGE's website at: https://portlandgeneral.com/about/who-we-are/resource-planning/cbre-procuring-clean-energy
Staff Recommendation 2: Energy/Capacity Actions – Long lead-time resource RFI …before issuing its next utility-scale RFP, PGE file a proposal to develop a long lead-time resource RFI… facilitate a workshop on the RFI findings, and allow sufficient time for stakeholder review of its RFI before proposing its next steps.	PGE's RFI results are discussed in **Section 5.6**; findings from the RFI were presented at a Roundtable: https://assets.ctfassets.net/416ywc1laqmd/2GF5BwVt9cR1MXtEpn6fli/e719ec6879183abd984928db360fe410/RFI_slides_jdg_web_1197.pdf
Staff Recommendation 3: • PGE shall conduct hourly production cost simulation of its preferred portfolio under the Reference Case in a manner that separately tracks hourly purchases and hourly sales. PGE will use this analysis to revise its GHG emissions forecast and to revise its submission to DEQ. • PGE shall update the Preferred Portfolio accordingly and provide a brief narrative explanation of the key planning insights derived from this exercise.	**Appendix D** outlines the steps that PGE has taken to update its GHG emissions forecasting to incorporate hourly analysis of its energy and emissions accounting. **Section 6.2.2** discusses hourly energy and emissions accounting results. PGE resubmitted the forecast for DEQ review in June 2025 prior to the filing date for this Update.
Transmission Analysis and Alternatives …we require a more complete analysis of the need and evaluation of the full range of available transmission solutions than was provided here, including non-wires alternatives when appropriate. PGE will need to present a risk-informed, cost-benefit analysis of all available transmission solutions for the 2030 time frame, including factors such as the associated timeline and cost risks, anticipated rate impacts, and the presence of longer-term or broader regional benefits.	**Sections 4.5 and 4.6** discusses transmission options for Portfolio Analysis.
B. Direction for Future Planning	

Action/Requirement	Applicable Section(s)
Staff Recommendation 4: Customer Actions and Guidance for Avoided Cost Update …direct PGE to work with Staff to propose a new method for calculating avoided costs in docket UM 1893… we direct PGE to collaborate with Staff and ETO to modernize the approach to long-term energy efficiency planning to use the best currently available information on energy efficiency and technical potential in future IRP and CEP updates.	PGE actively participated in the UM 1893 docket. PGE delivered this presentation on Redeveloping Avoided Costs for Energy Efficiency https://edocs.puc.state.or.us/efdocs/HAH/um1893hah329014025.pdf The Order adopting energy efficiency avoided cost data for use by Energy Trust is available here https://apps.puc.state.or.us/orders/2025ords/25-017.pdf Discussion of updates to the IRP price forecast as it relates to the UM 1893 docket is included in **Section 5.1.4**.
Staff Recommendation 5: Direct PGE in the next CEP/IRP Update to include an SSR compliance assessment. The SSR analysis should state the projected SSR compliance position broken out by relevant resource types and outline the actions the Company plans to take to fill any identified SSR shortfalls.	PGE's Small Scale Renewables Plan is discussed in **Section 6.4**.
Staff Recommendation 6 - Improved Engagement: …direct PGE to collaborate with Staff, stakeholders, peer utilities, and the CBIAGs in a dedicated collaborative to develop clear, actionable improvements to community and stakeholder engagement in subsequent CEP/IRPs.	PGE provided an update on improvements to community and stakeholder engagement in subsequent IRPs and CEPs here https://edocs.puc.state.or.us/efdocs/HAD/lc80had335791056.pdf
Staff Recommendation 7 – CBI by Next Update: …PGE must demonstrate development of CBIs ... we expect that some set of informational-only metrics be developed in time to be included with PGE's next RFP. If PGE cannot develop such metrics by its next CEP/IRP update, PGE must provide a detailed explanation of the barriers and constraints, along with a proposal for how and when PGE and its community stakeholders will be able to address them.	PGE has advanced the integration of CBIs into resource planning processes. Development, refinement, and application of CBIs is discussed in **Section 5.5**.
Staff Recommendation 8 – Report on Federal Incentives with Next Update: PGE should provide as much visibility into future opportunities as possible.	**Appendix A** provides an update on PGE's federal grant funding.

Action/Requirement	Applicable Section(s)
Staff Recommendation 9 - QF Renewals and Success Rates: …direct PGE to recalculate its IRP inputs using an assumption of 75 percent for QF renewals and the QF success rate for Schedule 202 projects. However, we read this narrowly and clarify that the avoided cost pricing inputs are not material to the IRP itself, but to the avoided cost price filing. We stress that the pricing inputs must be corrected due to their impact on the avoided cost price filing and decline to adopt PGE's recommendation to instead incorporate this change through an update.	**Appendix C** provides updated analysis for QFs.

Table 3 identifies the components of the 2023 CEP/IRP that were updated in this Update.

Table 3. Updated components of the 2023 CEP/IRP

Updated Component	Applicable Section(s)
Market development	**Section 2.2**
Transmission coordination	**Section 2.3**
Semiconductor and datacenter growth	**Section 2.4**
Load forecast	**Section 3.1**
2023 RFP	**Section 3.2**
Energy needs	**Section 3.3**
Capacity needs	**Section 3.4**
Regulatory-driven needs	**Section 3.5**
Transmission options and strategy	**Section 4.6**
Supply-side resource economics	**Section 5.1.2**
Demand Response forecast and economics	**Section 5.2**
Energy efficiency forecast and economics	**Section 5.3**
Small scale renewable (SSR) resources	**Section 5.4, 6.4**
CBIs	**Section 5.5, 6.5**
Long lead time resources	**Section 5.6**
Portfolio analysis	**Section 6.1**
Hourly energy accounting	**Section 6.2.2**
Preferred portfolio	**Section 6.2**
Resource Net Costs	**Section 5.1.9**
Federal funding opportunities	**Appendix A**
Non-emitting energy market (Brattle)	**Appendix F**

PGE's 2023 IRP Update does not revisit or update all analyses contained in the 2023 CEP/IRP. Instead, the 2023 CEP/IRP Update focuses on components that have the most impact on PGE's resource plan. The decision to forego updates in these following areas is driven by prioritization of critical elements that have a more direct impact on PGE's IRP outcomes. **Table 4** lists components that PGE will not be updating along with their corresponding location in the 2023 CEP/IRP.

Table 4. Components of the 2023 CEP/IRP not changed in this Update

2023 CEP/IRP Component	2023 CEP/IRP Location
Flexibility analysis	Section 6.8
Resiliency Chapter	Chapter 13
Tuned ELCCs	Appendix K
Market capacity study	Appendix G
Economics of CBREs	Section 8.3
CBRE Potential	Section 7.2
Utility vs PPA analysis	Section 8.6

Chapter 2. Planning environment

PGE's long-term planning adapts to evolving laws, policies, technological advancements, economic conditions, and climate change impacts. These factors influence resource economics, customer prices, community benefits, and ultimately shape PGE's resource decisions to serve its customers effectively. This chapter explores the broader planning context influencing the overall resource strategy to meet customers' energy needs reliably while keeping prices as low as possible and achieving emissions reduction requirements.

Key Highlights

- Under the new Federal Administration, the EPA is reconsidering the powerplant emission limit final rules established on April 25, 2024, under Section 111 of the Clean Air Act. The details of this and other policy changes at the federal level remain uncertain, though Congress is actively evaluating proposals that would remove federal tax incentives for new non-emitting generation and storage resources. The analysis in this Update mainly contemplates current known final rules, with the exception of sensitivity analyses that exclude tax credits, further described in **Section 6.6 Federal tax credit availability scenarios**.
- PGE has signed an implementation agreement for CAISO's Extended Day-Ahead Market (EDAM) go-live in October 2026.
- PGE is currently developing regional alignment on Resource Adequacy planning standards as a precursor for a regional reliability program.
- The Western Transmission Expansion Coalition's (WestTEC) West-Wide Transmission Study Project represents a new regional effort to address transmission constraints.
- Large industrial customer growth is expected to increase regional electric demand across the Western Interconnection.

Developments Since 2023 IRP

The planning environment has evolved significantly since the 2023 CEP/IRP filing, with changes to federal regulations and policies, progress on market design implementation, and increased focus on regional transmission planning. Additionally, this Update addresses the challenge and opportunity of unprecedented industrial load growth, highlighting PGE's regulatory efforts to ensure appropriate cost allocation for large customer connections.

Strategic Implications

Load growth for industrial customers is expected to significantly increase the quantity of generation, storage and transmission resources required to maintain system reliability and reduce emissions. Change in Oregon ratemaking policy also creates an opportunity to equitably serve large industrial customers while building infrastructure that supports reliability for all customers. Other opportunities to maximize the efficiency of PGE's resource portfolio are advancing through participation in EDAM and regional resource adequacy frameworks. The change in federal administration creates considerable near-term uncertainty regarding tax credit support for clean energy resources.

Staff Recommendations Incorporated

This section addresses Staff Recommendation 8 referenced in LC 80 Order No. 24-096, which directs PGE to include a report on federal incentive implementation and its key impact on the company's Action Plan.[11]

2.1 EPA powerplant rules

When planning for PGE's customer needs, PGE must monitor trends that impact the Western Interconnect of the North American power system. One important trend relates to federal policy and regulations imposing compliance requirements on thermal generation resources. For example, on April 8, 2025, President Trump granted a two-year compliance exemption for various affected facilities subject to the Mercury and Air Toxics Standards, including the Colstrip facility in Montana for which PGE has partial ownership. Pursuant to section 112 of the Clean Air Act, these rules set emissions limits for filterable particulate matter for coal-based generating units.

The implementation of these and other rules is undergoing significant challenges under the current Administration and is being targeted for reconsideration by the United States Environmental Protection Agency (EPA). Additionally, several states and industry groups have filed lawsuits against them in federal court. These challenges and agency reconsideration actions will take time, and the outcomes remain uncertain. PGE will continue to evaluate EPA rules to assess the impact they may have on PGE resource plans.

2.2 Market development

Regional market integration offers PGE and other western utilities opportunities to lower costs, enhance reliability, and integrate diverse resources through the efficient use of existing resources. To maximize the use of existing transmission infrastructure and benefit from least cost resources available in a regional energy market, PGE has elected to participate in CAISO's EDAM. As a separate effort to address regional resource adequacy challenges, PGE has

[11] OPUC. Acknowledgement of 2023 Integrated Resource Plan and Clean Energy Plan. Docket No. LC 80, December 14, 2023. Retrieved from https://edocs.puc.state.or.us/efdocs/HAU/lc80hau325590032.pdf.

engaged in the Western Resource Adequacy Program (WRAP), led by the Western Power Pool (WPP). The WRAP has established a region-wide approach for assessing and addressing resource adequacy with future opportunities for providing operating efficiencies, diversity, and sharing of pooled resources.

The combination of a regional resource adequacy program such as WRAP, which will facilitate capacity adequacy for each participant, and EDAM, which will enable the most efficient economic dispatch of all resources to meet load, is expected to support delivery of reliable power at the lowest possible cost for customers.

2.2.1 CAISO's Extended Day Ahead Market

PGE currently participates in the Western Energy Imbalance Market (WEIM) for dispatch optimization inside the hour, which is operated by the CAISO and supports over 80 percent of the load in the Western Interconnection. The WEIM lowers energy costs for customers, enhances reliability through wide area visibility and integrated generation dispatch, and supports renewable resource integration. The WEIM has proven to be a critical tool for maintaining reliability during extreme weather events, brining energy from areas of surplus to those experiencing peak events. Since joining the WEIM in 2017, PGE has supported the development of regional solutions that enhance reliability, promote clean energy, and incrementally advance western markets to lower costs for customers.[12]

Based on PGE's day-ahead market comparative analysis, PGE selected EDAM as the preferred market choice to maximize the benefits of a day-ahead market for PGE's customers. The benefits of participation are outlined in an informational filing titled Comparative Analysis of CAISO's EDAM and SPP's Markets.[13] In addition, PGE has identified a review of markets access assumptions to determine the impact of EDAM on the expansion in market capacity as an item for review in the 2026 CEP/IRP. On July 2, 2024, PGE signed an implementation agreement with CAISO for participation in EDAM with market go-live in October 2026. This day-ahead market complements PGE's participation in the current bi-lateral market, in which PGE already operates. PGE considers dual participation to be necessary until there is greater market participation in EDAM across Western Electricity Coordinating Council (WECC) market participants. Additionally, on April 3, 2025, PGE filed revisions to its Open Access Transmission Tariff (OATT) for EDAM participation with the Federal Energy Regulatory Commission (FERC).[14]

EDAM leverages CAISO's existing day-ahead market, cost efficiently building on the successful WEIM platform. EDAM offers a cost-effective, incremental option that builds upon the successes

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[12] For example, PGE has chaired the WEIM Regional Issues Forum, and is co-chair of the West-wide Governance Pathways Initiative.

[13] Portland General Electric. (2024, March 21). Comparative analysis of the CAISO's EDAM and the SPP's markets: PGE informational filing on commitment to the California Independent System Operator's extended day-ahead market (OPUC Docket No. LC 80). Oregon Public Utility Commission. https://edocs.puc.state.or.us/efdocs/HAH/lc80hah327479040.pdf

[14] Federal Energy Regulatory Commission. (2025, April 3). Portland General Electric Company submits tariff filing per 35.13(a)(2)(iii): Revisions to Portland General Elec. OATT to implement EDAM to be effective 6/2/2025 (ER25-1868) [Filing Type: 10; Document Accession No. 20250403-5095]. https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20250403-5095

and proven economic benefits of WEIM, while maximizing the value of PGE's existing investments in market software and communication systems to join the only currently operating day-ahead market in the West. With over 50 percent of the load in the western interconnection current committed to or leaning towards EDAM, the market offers a contiguous transmission footprint with significant resource diversity and transfer capacity. This contiguous footprint allows the EDAM to better optimize the diverse resources, including wind, solar, hydro, and thermal resources. The EDAM offers a robust platform for continued market evolution for PGE.

EDAM optimizes all supply and demand across the market footprint while respecting transmission limitations to produce optimized day-ahead schedules. All generation and load within a participating EDAM Balancing Authority Area (BAA) must either economically bid or self-schedule in the market. These transactions are then re-optimized in the existing WEIM sub-hourly 15- and 5-minute markets. EDAM requires participants to demonstrate sufficient energy, capacity, flexibility, and transmission on a day-ahead basis, consistent with forecasted demand.

The EDAM transmission framework is designed to maximize transmission availability while respecting the OATT rights and legacy contracts of participants. The transmission availability within the EDAM design seeks to maximize the amount of transmission capability made available to the market across a variety of transmission service arrangements. Prior to the day-ahead market run, each EDAM Entity will identify the firm and conditional firm transmission capacity that can be made available to support reliable transfers. Any additional unsold firm available transfer capability (ATC) will be made available to support transfers between EDAM BAA's. The transmission service provider maintains the responsibility to plan and operate the transmission system within the BAA and administer cost allocation in accordance with the OATT.

EDAM accounts for the costs arising from state GHG accounting and reduction policies that price GHG. CAISO has convened a regional stakeholder process to modify the GHG framework to account for a non-priced GHG-capped state policy. PGE is actively participating in this process with Oregon regulatory agencies to develop an emissions report which may enable GHG attribution for EDAM and WEIM market purchases under HB 2021 reporting requirements.

The benefits of EDAM are expected to grow following the expansion of the market footprint. With an eye to the potential for future expansion, the market is revisiting its governance model. EDAM has adopted a joint authority governance model informed by the regional West-wide Governance Pathways Initiative that includes oversight roles for state commissions through the Body of State Regulators and for stakeholders though the Regional Issues Forum. Notably, the West-wide Governance Pathways Initiative aims to develop and establish a new and independent entity with an independent governance structure capable of overseeing an expansive suite of West-wide wholesale electricity markets and related functions. Senate Bill 540 was recently introduced in the California legislature to enable California investor-owned utility participation in this new regional organization. For more information on the West-wide Governance Pathways Initiative, please visit the Western Interstate Energy Board website.[15]

[15] Western Interstate Energy Board. https://www.westernenergyboard.org/wwgpi/

As PGE moves towards participation in EDAM, several regulatory and procedural milestones are required prior to go-live. The first major step is a tariff filing that is currently pending with FERC[16] PGE will also need to file with FERC for Market-Based Rates (MBR) to ensure that no single market participant has market power. Finally, PGE must demonstrate to FERC that it meets the Readiness Criteria established in the CAISO tariff. Details on these filings and other EDAM implementation milestones can be found on the WEIM website[17]. It is also likely that a tariff update with the OPUC will be required to enable some programs to be adequately represented in EDAM.

For more information on CAISO's EDAM, please visit the CAISO website.[18]

2.2.2 Western Resource Adequacy Program (WRAP)

WRAP is an industry-initiated and led resource adequacy planning standard and compliance framework designed to meet the growing resource adequacy challenge and enhance reliability in the region. On April 16, 2024, in docket AR 660, the OPUC adopted new resource adequacy (RA) rules which mirror the WRAP program requirements in many ways. Participation in the state RA program is mandatory for IOUs and ESSs that do not voluntarily participate in WRAP.

The WRAP is a planning standard and compliance framework that seeks to take advantage of and maximize regional diversity in resources and load to enhance reliability for all customers across the WRAP footprint. The program experienced numerous delays since FERC initially approved the tariff in early 2023. First scheduled to become binding Summer 2025, participants expressed concern in their ability to meet capacity requirements due to supply chain issues and increases in peak-load driven by electrification and data centers. [19,20] In September 2024, a revised transition plan was accepted by the Western Power Pool Board of Directors and the program is now scheduled to be binding beginning Winter 2027-2028. Although the regional RA planning standard established by WRAP will not become binding until Winter 2027-2028 at the earliest, it is a first step towards a common reliability planning standard. As the region moves to align with the WRAP planning standard, PGE continues to explore options to operationalize this planning standard to achieve enhanced reliability through diversity sharing.

In addition to WRAP, in UM 2143, the OPUC adopted Staff recommendation to open a formal rulemaking on resource adequacy. The OPUC then adopted new rules in Docket AR 660 requiring electric companies and electric service suppliers to provide a Binding Forward

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[16] Federal Energy Regulatory Commission. (2025). Portland General Electric Company submits tariff filing per 35.13(a)(2)(iii): Revisions to Portland General Elec. OATT to implement EDAM to be effective 6/2/2025 (FERC Docket No. ER25-1868) [Filing Type: 10]. https://elibrary.ferc.gov

[17] California Independent System Operator. (n.d.). Extended Day-Ahead Market Implementation and Onboarding. Western Energy Imbalance Market. Retrieved June 3, 2025, from https://www.westerneim.com/Pages/ExtendedDayAheadMarketImplementation.aspx

[18] California Independent System Operator. Western Energy Markets: Extended Day-Ahead Market (EDAM). CAISO, 2024, https://www.westerneim.com/Pages/ExtendedDayAheadMarket.aspx.

[19] FERC Order Accepting Proposed Tariff re Northwest Power Pool under ER22-2762. Feb. 10, 2023

[20] WRAP Participant Letter, April 24, 2024

Showing consistent with state program requirements.[21] The company believes that the reliability challenges facing PGE and the greater Western region warrant the continued development of State RA rules, especially considering recent delays in the WRAP. The efficiencies presented by the pooling of resources will be an important tool to address PGE's future capacity needs at lowest costs.

As a result of UM 2143 and AR 600, PGE has modified its resource adequacy modeling under the 'State RA Requirements' scenario. This method uses WRAP standards instead of using the PGE resource adequacy method in portfolio analysis. Results of this analysis are presented in **Section 6.3.5 State RA requirements**.

2.2.3 Hydroelectric Contract Availability and Competition

PGE is facing increased competition for existing resources such as Mid-Columbia hydroelectric power and BPA marketed Federal hydroelectric power, driven by rising demand from data centers and growing Public Utility Districts (PUDs) loads. This heightened competition is raising market prices, and as a result, PGE must pay higher contract rates to secure access to carbon-free, dispatchable, and highly flexible resources – ultimately impacting the cost of delivering reliable, clean energy to our customers.

2.3 Transmission coordination

This section describes the Western Transmission Expansion Coalition (WestTEC) effort and how this effort will help PGE pursue cost-effective transmission projects. As of March 2025, the WestTEC effort is in the study phase. Therefore, the information discussed here is the most up-to-date as of finalization of this 2023 CEP/IRP Update.

2.3.1 Western Transmission Expansion Coalition (WestTEC)

The objective of the Western Transmission Expansion Coalition (WestTEC) West-Wide Transmission Study Project (Project) is to produce an actionable 10-year and 20-year transmission study based on transmission portfolios that enhance Western reliability while also considering economic efficiencies and state policy goals.[22]

WestTEC includes collaboration between diverse sectors of the energy industry, states, and tribes. The project will address interregional and interstate transmission needs spanning the Western Interconnection, including the collective footprint of the existing three regional planning organizations for the West (NorthernGrid, the California Independent System Operator, and WestConnect) as well as interties with Canadian Provinces.

The goal of the 10-year and 20-year transmission study is to provide a high quality, high confidence foundation for future transmission build decisions and actions that can be

[21] Oregon Public Utility Commission. (2023, September 22). Order No. 23-340: UM 2143/AR 660 – Staff's recommendation adopted [Docket No. UM 2143; signed by Commissioners Megan Decker, Letha Tawney, and Mark Thompson]. https://apps.puc.state.or.us/orders/2023ords/23-340.pdf

[22] Western Transmission Expansion Coalition. (2024, July 19). Study plan (Draft V4). Western Power Pool. https://www.westernpowerpool.org/private-media/documents/WestTEC_Study_Plan_Draft_V4.pdf

undertaken by the industry. WestTEC uses an independent consultant to focus on identifying interregional and interstate transmission expansion solutions that are based on an assessment of the consolidated and coordinated needs of western utilities, not just a single utility or regional planning organization. Consistent with methodologies identified in FERC Order No. 1920 (**Appendix H.2 FERC Order 1920 process**), WestTEC measures important regional transmission benefits including production cost savings, reduced congestion, and mitigation of extreme weather events.[23] Following the completion of the WestTEC studies, specific transmission solutions will be available for study in the IRP.

The WestTEC 10-year horizon transmission study will be complete in August 2025 and the 20-year horizon transmission study will be complete in September 2026. Given that the first study will not be completed until August 2025, nearer term transmission projects will not go through the Project.

For additional details on scheduled transmission projects, see **Section 4.2 PGE transmission projects.** The transmission options modeled in the 2023 CEP/IRP Update are described in **Section 4.6 Transmission options for portfolio analysis**. The cumulative transmission buildout selected in the Preferred Portfolio is presented in **Section 6.2 Preferred Portfolio**.

2.4 Industrial load growth

This section outlines the general trends in electricity demand, with a particular focus on the Pacific Northwest and the role of large industrial customers, such as data centers and semiconductor producers, in driving this demand as well as the regulatory and policy responses in Oregon.

2.4.1 General trends in electricity demand across the Western Interconnection

While the western interconnection has historically seen modest growth in electricity demand, recent developments signal a period of rapid expansion, particularly in industrial sectors such as technology and manufacturing. Several key factors are contributing to this shift including the transportation electrification, manufacturing, and building electrification. A significant driver of industrial load growth is the expansion of data centers. These facilities provide cloud storage, computing power, and digital infrastructure and require significant electricity to power servers, cool buildings, and maintain continuous operations.

2.4.2 Industrial load growth in the Pacific Northwest

The Pacific Northwest is particularly attractive to large industrial customers due to its cooler climate, which reduces cooling costs, proximity to the Trans-Pacific Submarine Cables that terminate in Hillsboro, and access to abundant renewable energy from hydropower, wind, and solar sources–leading to relatively lower electricity costs. Due to these factors, the region has seen significant recent investment. The Oregon CHIPS Act (SB 4) provides state funding and regulatory support to strengthen Oregon's semiconductor industry by aligning with the federal

[23] FERC Order No. 1920, issued on May 13, 2024 and FERC Order No. 1920-A, issued on November 21, 2024.

CHIPS and Science Act. It streamlines permitting and invests in site development to help Oregon compete for federal semiconductor manufacturing incentives.[24]

Industrial load growth presents substantial opportunity and benefit for PGE's customers. PGE's service of industrial load growth includes infrastructure that supports reliability for all customers. Additional benefits may accrue to all customers should large industrial backup generation or other resources tied to these customers be made available for grid reliability and flexibility. As noted below, PGE is also actively involved on several fronts to ensure that costs to serve the rapid industrial load growth is appropriately allocated to the customers driving the expense.

2.4.3 Regulatory and policy responses to large customer demand growth

The 2025 Legislature enacted House Bill 3546, requiring the creation of a separate rate class for large energy use facilities and allocating the costs of serving these large energy use facilities in a manner that is equal or proportional to the cost of serving the class.[25] The bill also requires utilities to enter contracts to serve certain large energy use facilities.

PGE has revised its tariff to provide for appropriate cost allocation to the growing large industrial customers including through the addition of new study fees, minimum demand charges, and deposits, aiming to prevent stranded assets and incentivize large customers to invest in grid resiliency. PGE's revised tariff also includes provisions to mitigate cost-shifting risks, particularly for distribution and transmission investments, while providing that costs are appropriately allocated, and large customers pay for the cost to connect and serve their energy needs.[26] Whether these changes remain in place or are revised as well as implementation of HB 3546 are issues under consideration by OPUC in a pending docket, UM 2377, creating uncertainty regarding industrial load cost allocation, particularly with data centers.[27] This leads to uncertainty in the cost forecasts in the IRP.

In UM 2024, OPUC is reviewing Oregon's Direct Access Program, which allows large customers to contract directly with third-party electricity service suppliers. In UM 2024, OPUC is conducting a holistic review of the Direct Access Program. The review includes but is not limited to transition adjustment charges, election windows for customers to opt into the DA program, default pricing for Direct Access customers, and all load serving entities (including energy service suppliers and utilities) resource adequacy.

The impacts of large customer industrial load growth are evaluated within the Update as a scenario within portfolio analysis. A detailed description of the results of this scenario can be found in **Section 6.3.3 Large industrial customer growth**.

[24] Oregon State Legislature. (2023). Oregon CHIPS Act, S.B. 4, 82nd Leg., 2023 Regular Sess. https://olis.oregonlegislature.gov/liz/2023R1/Measures/Overview/SB4
[25] As of this publication, the bill awaits the Governor's signature.
[26] UE 430, Investigation into PGE's New Load Connection Costs.
[27] UM 2377, PUC Investigation of Rule C and I, Marginal Cost Study Treatment.

2.5 Federal administration changes

There has been a change in the Federal Administration since the 2023 CEP/IRP. During its first 100 days in 2025, the Trump Administration has taken a range of actions aimed at energy independence and deregulation, the full impacts of which are uncertain but likely to delay and increase the cost of renewable energy development and roll back environmental regulations. Due to uncertainties or lack of new final rules, most anticipated changes are not incorporated into this analysis.

2.5.1 Tax credit policy

The Inflation Reduction Act (IRA) of 2022 authorized approximately $270 billion in energy security and climate resilience investments, with a central focus on enhancing and expanding tax-based incentives for clean energy deployment.[28] A cornerstone of the IRA was the long-term extension and modernization of the Investment Tax Credit (ITC) and the Production Tax Credit (PTC), which had historically faced repeated expirations and short-term renewals that constrained planning and investment.[29] The IRA extended these credits for projects that begin construction before January 1, 2033, and transitions to a technology-neutral credit regime beginning in 2025. On a forward going basis, the IRA awards tax incentives based on the emissions profile of the generation source rather than technology type.[30] The IRA introduced tax credit transferability allowing eligible taxpayers to transfer all or part of certain tax credits to unrelated parties in exchange for cash, creating a new market for credit buyers and sellers.[31] This provision aimed to simplify financing, reduce dependence on complex tax equity structures, and make clean energy investment more accessible to a broader set of developers, utilities, and nonprofit entities.

While the Inflation Reduction Act (IRA) of 2022 provides funding and tax credits (including the ITC and PTC) through at least 2032, the current administration has introduced significant uncertainty regarding the future of the IRA and its provisions. In the executive order issued on January 20, 2025, the administration placed an immediate pause on the disbursements of funds appropriated through the IRA.[32] Federal Judges have issued orders requiring the administration to resume IRA funding, but the effect on the overall policy environment has been chilling to clean energy development, with potential modifications to key provisions affecting the stability and predictability of clean energy investments.[33] Congress is also working to phase out and condition many IRA tax credits, including the 45Y and 48E tax credits that provide significant value for PGE customers as PGE invests in clean energy. The outcome if this legislative effort is not yet known.

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[28] Inflation Reduction Act of 2022, Pub. L. No. 117-169, Title I, Subtitle D.
[29] IRC § 48 (ITC) and IRC § 45 (PTC), as amended by IRA §§ 13102 and 13101
[30] IRC §§ 45Y and 48E, created by IRA §§ 13701 and 13702
[31] IRC § 6418
[32] Executive Order 14154, "Unleashing American Energy" (January 20, 2025), https://www.whitehouse.gov/presidential-actions/2025/01/unleashing-american-energy/.
[33] *State of New York v. Trump*, Case 1:25-cv-00039-JJM-PAS, D.R.I., (February 10, 2025), https://storage.courtlistener.com/recap/gov.uscourts.rid.58912/gov.uscourts.rid.58912.96.0_6.pdf. *Woonasquatucket River Watershed Council v. Department of Agriculture*, Case 1:25-cv-00097-MSM-PAS, D.R.I., (April 15, 2025), https://storage.courtlistener.com/recap/gov.uscourts.rid.59116/gov.uscourts.rid.59116.45.0.pdf.

In response to this shifting policy landscape, PGE's IRP Update includes portfolio sensitivity analysis assessing the impacts of reverting to a pre-IRA planning environment. The details regarding the design of this scenario are introduced in **Section 5.1.3 Tax credit sensitivities** and results of the scenario analysis are provided in **Section 6.6 Federal tax credit availability scenarios**.

2.5.2 Grant funding

PGE and joint applicants were awarded USDOE grant funding in 2024 through the Grid Resilience and Innovation Partnerships (GRIP) Program to support some transmission projects. There is uncertainty whether these federal dollars will be fully awarded or not as payments were paused by the time of this Update publication. The analysis assumes this funding is awarded to support the selected projects described in **Section 4.6 Transmission options for portfolio analysis**. Further, **Appendix A Federal grant funding** details grants awarded to PGE. The delivery of these grants remains uncertain due to developing policy priorities at the Federal Administration.

2.5.3 BPA

Federal Administration changes have impacted BPA processes and workforce. The Transmission Service Request Study and Expansion Process (TSEP) to evaluate and address transmission service requests has been paused. Significant workforce reductions and current rehiring processes may impact operations, load service, and resource procurement.

On September 30, 2028, the existing settlement of the Residential Exchange Program (REP) is set to expire. PGE is still in active conversation and negotiation with BPA to make sure PGE customers receive an equitable share of the benefits of the Federal system. There is significant uncertainty associated with the impact of the expiration of the existing REP settlement and the level of REP benefits that BPA will make available to PGE's residential and eligible small farm customers. However, the OPUC has estimated that removal of the existing REP benefits that customers currently receive through the BPA REP program would create a cost impact to customers equivalent to around a 3.6 percent rate increase.

The ultimate implications of changes at BPA are uncertain but have the potential to impact day to day grid operations and slow regional transmission investment and development necessary for reliability and growth. This Update does not contemplate these complications.

Chapter 3. System needs

This chapter quantifies the drivers of energy and capacity needs in the 2023 CEP/IRP Update. The analyses described below provide the foundational metrics for addressing resource adequacy, decarbonization objectives and other policy requirements while minimizing long-term costs and risks. Previous modeling approaches for evaluating PGE's demand, supply, and policy requirements were described in the 2023 CEP/IRP's Chapter 6 – Resource needs and in the 2023 CEP/IRP Addendum, Chapter 2 – Need changes.[34,35] Additionally, this chapter discusses the 2023 Request for Proposal (RFP) results and the competitive bidding process initiated following the 2023 CEP/IRP.

Key Highlights

- Twenty-year average annual growth rates are estimated at 2.8 percent annually, a 1.2 percentage point increase from the 2023 CEP/IRP Addendum forecast. Growth is driven primarily by unprecedented industrial sector expansion, especially in semiconductor manufacturing and data centers.
- Resources assumed to be added following the conclusion of the 2023 RFP reduce long term capacity needs and make important contributions to addressing near-term capacity deficits.
- PGE continues to procure resources as part of the 2025 RFP. Such resource additions are likely to enter the system approximately 2029, limiting near-term emissions reductions.
- Monthly assessment of PGE's long-term energy need increases resource need relative to annual energy accounting.

Developments Since 2023 IRP

Since the 2023 IRP, PGE updated its load forecast methodology, shifting from a dual-horizon econometric analysis to an econometric model which spans the entire planning horizon and incorporates recent hourly demand data. This adjustment better captures current trends, including rapid industrial growth and changing residential energy use patterns post-COVID-19. Monthly energy need analysis was introduced to reflect the variability in renewable energy generation more accurately. Additionally, forecasts for distributed energy resources (DER) have been refined, further impacting projected energy and capacity needs.

Strategic Implications

The updated forecasting methods and revised growth projections underscore the urgency and scale of PGE's resource planning efforts. The significant industrial sector

[34] 2023 CEP/IRP
[35] 2023 CEP/IRP Addendum: System Needs and Portfolio Analysis Refresh

expansion necessitates timely resource procurement and infrastructure development to manage unprecedented demand increases.

Staff Recommendations Incorporated

This section discusses IRP Updates which incorporate Staff Recommendations #3, #5, and #9 from Order No. 24-096. Recommendation #3 is advanced by representing non-emitting resource needs in a more granular accounting of PGE's forecasted emission through the quantification and incorporation of monthly energy needs in portfolio modeling. Recommendation #5 is addressed by explicitly accounting for Small-Scale Resource need in the IRP modeling. Lastly, Recommendation #9 is incorporated by assuming 75 percent renewal rate of QF resources in IRP inputs for capacity and energy.

3.1 Econometric load forecast

PGE customer's load forecasts have grown since the 2023 CEP/IRP filing which is demonstrated in this section's discussion of the PGE's May 2024 load forecast. The Addendum to PGE's 2023 CEP/IRP increased the load forecast from the initial filing and, unless noted, comparisons to the 2023 CEP/IRP refer to the Addendum.[36] PGE's load forecast includes two methodological changes to the Energy and Peak Forecasts which account for current trends and differences compared to the previous filing.[37] Additionally, PGE presents a high and low load forecast which include wider bounds in the near term to reflect increased uncertainty in industrial segment growth. Load forecasts exclude direct-access customers, consistent with 2023 CEP/IRP – Section 6.1.1 and in response to Order No. 07-022, IRP Guideline 9.[38]

The industrial segment is expected to be the focus of growth in PGE's service area due to the semiconductor industry and data centers. As **Section 2.4.2 Industrial load growth in the Pacific Northwest** describes, PGE's service area has experienced a dramatic increase in semiconductor and data center investment, a segment that is positioned to grow dramatically as cloud computing and AI demands increase. As this growth is unprecedented, the pace and scale of the electricity demand required to serve these needs introduces increased uncertainty in the outlook.

Forecasts of distributed energy resources (DERs), including rooftop solar, transportation and building electrification, are additional to the underlying econometric load forecast (base forecast). The energy and peak load impact of DERs, further referred to as electrification, are

[37] May 2024 Forecasts are the vintage used in the 2023 CEP/IRP Update. More recent vintages are not used as load forecasts are one of the furthest upstream inputs in the modeling process. The Sept. 2024 forecast estimates suggest a nominal change in average energy deliveries and seasonal peak loads across the planning horizon, and more recent forecasts are not expected to materially change the 2023 CEP/IRP Update's final recommendations.

[38] In the Matter of Public Utility Commission of Oregon, Investigation Into Integrated Resource Planning, Docket No. UM 1056, Order No. 07-002 (Jan 8, 2007) at 19, available at: https://apps.puc.state.or.us/orders/2007ords/07-002.pdf

estimated in PGE's AdopDER model, as discussed in **Section 5.2.2 Cost-effective demand response**. In the sections below, electrification forecasts from AdopDER are combined with results from the base forecast to provide a more complete forecast of energy and peak load estimates across the planning horizon. Resource need representations presented in **Sections 3.3 Energy need** and **Section 3.4 Capacity need** also consider the cumulative load forecasted for both PGE's base service area demand and the incremental impact of electrification.

3.1.1 Energy forecast

Recent years have marked a period of meaningful change in how PGE's customers use energy. **Figure 12** shows energy deliveries growth by customer class presented using a five-year rolling average growth rate. Across the past decade the industrial segment has offset relatively flat energy usage in the residential and commercial segments due to growth in high-tech and data center sectors. Growth from these sectors is estimated to account for approximately 75 percent of load growth between 2025-2030 (**Figure 17**), 50 percent of 2030 seasonal capacity need, and 30 percent of portfolio resources in 2030 (**Section 6.3.3 Large industrial customer growth**). Increased growth in industrial energy deliveries is expected to continue as Oregon's semiconductor industry grows and data center demand from cloud and AI uses expands. This rapid load growth presents economic opportunities for the region and is driving new policy and planning considerations to ensure PGE's system remains reliable and affordable in the face of unprecedented change. As part of these new considerations, the 2023 CEP/IRP Update includes a new model structure for PGE's energy deliveries forecast that allows for direct incorporation of individual large customer load growth projections.

Figure 12. Five-year average growth rates by class

3.1.1.1 Energy Forecast Methodological Changes

PGE's updated energy deliveries forecast includes two primary components: econometric forecast models by rate schedule and customer specific forecasts for a selection of large

customers. As part of the 2023 CEP/IRP Update, the Company revised the econometric forecast model.

The econometric portion of PGE's model ties energy deliveries to macro-economic drivers, primarily residential building permits and employment. PGE's residential models segment customers by dwelling type and estimates both usage per customer and customer count. The commercial models are segmented by rate schedule and energy deliveries are estimated directly.

A key update to the econometric model is that PGE no longer splits its forecast into two horizons as it has in the past (1–5-year vs long term). A single set of regression models now span the full horizon of the 20-year CEP/IRP planning horizon. **Table 5** summarizes the groupings used for the econometric regression models.

Table 5. Structure of regression models

Dependent Variable	Model Groups
Usage Per Customer	Residential Single Family, Multi Family and Manufactured Home
New Connect	Single Family, Multi Family and Manufactured Home
Monthly Energy Deliveries	Non-residential Rate Schedules: 32, 38, 83, 85, 89 Other Residential Misc. Schedules: Irrigation, Area Lighting, Street Lighting and Traffic Signals

3.1.1.2 Large customer forecast

Consistent with the 2023 CEP/IRP, the large customer forecast is an individual forecast for a subset of large customers with high energy intensity, such as large non-residential customers on Rate 89, and 90.[39] These customers can experience stepwise changes in operations which are often communicated by the customer to PGE but are not easily predicted by reliance on regional macroeconomic drivers. Information used to develop these forecasts includes customer requests, segment industry reports, historic load-ramps, and comparisons to like customers. The state legislature and OPUC are actively discussing policy regarding industrial customer cost allocation as part of HB 3546 and UM 2377.[40,41] These efforts will further refine methods for differentiating large customer load in future planning cycles.

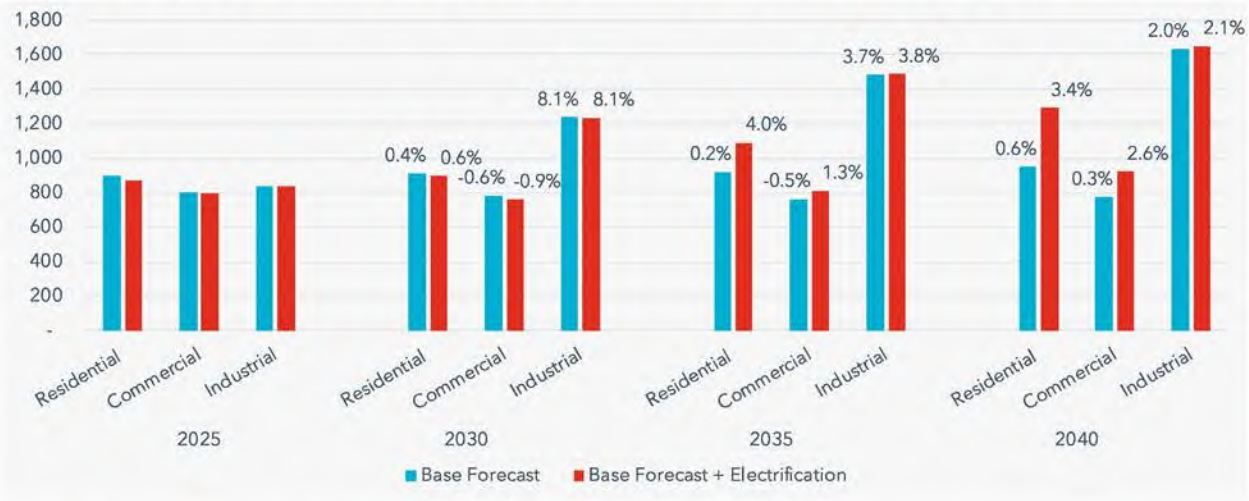
3.1.1.3 Resulting Energy Forecast

PGE's average growth rate for energy over the next 20 years is forecasted to be 1.9 percent, not including the impacts of electrification. This growth rate increases to 2.8 percent after including

[39] https://portlandgeneral.com/about/info/rates-and-regulatory/tariff
[40] Oregon HB 3546
[41] UM 2377

electrification estimates from PGE's AdopDER model.[42] Both the residential and commercial sectors are expected to remain relatively flat through 2030, with energy efficiency mostly offsetting customer growth in the near-term. After 2030, demand from non-industrial customers grows with increased electrification. The industrial sector is forecast to grow rapidly, driven primarily by semiconductor and data center sector growth. **Figure 13** shows the magnitude of customer class load at five-year increments and growth rates associated with the preceding five-year period. Industrial total usage is forecasted to surpass the residential and commercial sectors by 2030.

Figure 13. Energy forecast at five-year increments, with annual average growth rates



3.1.1.4 Energy High and Low Forecasts

PGE creates high and low load forecasts to account for different economic futures. The health of Oregon's economy impacts PGE's load growth, with residential driven by population and commercial driven by employment. In addition to the population and employment scenarios, PGE accounted for different large customer growth futures. The industrial sector has the widest bounds, accounting for the increased uncertainty in this sector. **Table 6** presents a growth rate summary comparing PGE's reference, high and low load forecasts for the base forecast and including the effects of electrification as estimated in AdopDER.

PGE notes that strong demand for industrial load service contributes to the uncertainty of the load forecast. PGE has received service requests from many large industrial customers whose requested load service is not included in the Reference case load forecast. PGE's choice to exclude many of these industrial requests is supported by PGE's judgement on the maturity of these requests and the absence of commitments from such customers. Ongoing policy discussions regarding the fair allocation of system costs to such customers discussed in **Section 2.4.3** contributes to the uncertainty of PGE's industrial load forecast. PGE's High load forecast

[42] AdopDER provides electrification estimates for residential and non-residential segments. Non-residential electrification estimates are weighted 90/10 (commercial/industrial) as most programs are targeted to commercial customers.

partially captures the potential of still stronger industrial service demand to be further assessed following these policy determinations.

Table 6. High, reference, and low forecasts

	High		Reference		Low	
	Base	Base + Electrification	Base	Base + Electrification	Base	Base + Electrification
Total Energy	3.31%	4.11%	1.94%	2.87%	0.58%	1.12%
Residential	1.02%	2.65%	0.44%	2.25%	-0.15%	0.71%
Commercial	0.50%	1.78%	-0.05%	1.13%	-0.75%	-0.06%
Industrial	7.48%	7.55%	5.14%	5.22%	2.87%	2.94%

3.1.1.5 IRP Update Comparison to 2023 CEP/IRP

Table 7 shows twenty-year average annual growth rates by customer segment for the 2030 CEP/IRP Update compared against the previous 2023 CEP/IRP and Addendum: System Need and Portfolio Analysis Refresh filings. The May 2024 update resulted in an increase in forecasted annual growth rates, from 1.6 percent in the filed addendum to 1.9 percent. The residential and commercial sectors both saw moderate decreases in forecasted growth prior to the inclusion of electrification. After including electrification, estimates for residential and commercial sectors grew by an additional 1.8 and 1.1 percentage points, respectively. The industrial sector increased from the Addendum estimate of 3.9 percent to 5.1 percent in the May 2024 Forecast, prior to electrification. Overall, the five-year forecast remained consistent with the prior update while the long-term growth rate saw an increase. This increase is primarily driven by the methodology update presented in **Section 3.1.1.1 Energy Forecast Methodological Changes**.

Figure 14 presents a graphical comparison of the forecast vintages including a segment build of the most recent, May 2024 load forecast.

Figure 14. Comparison across load forecast vintages

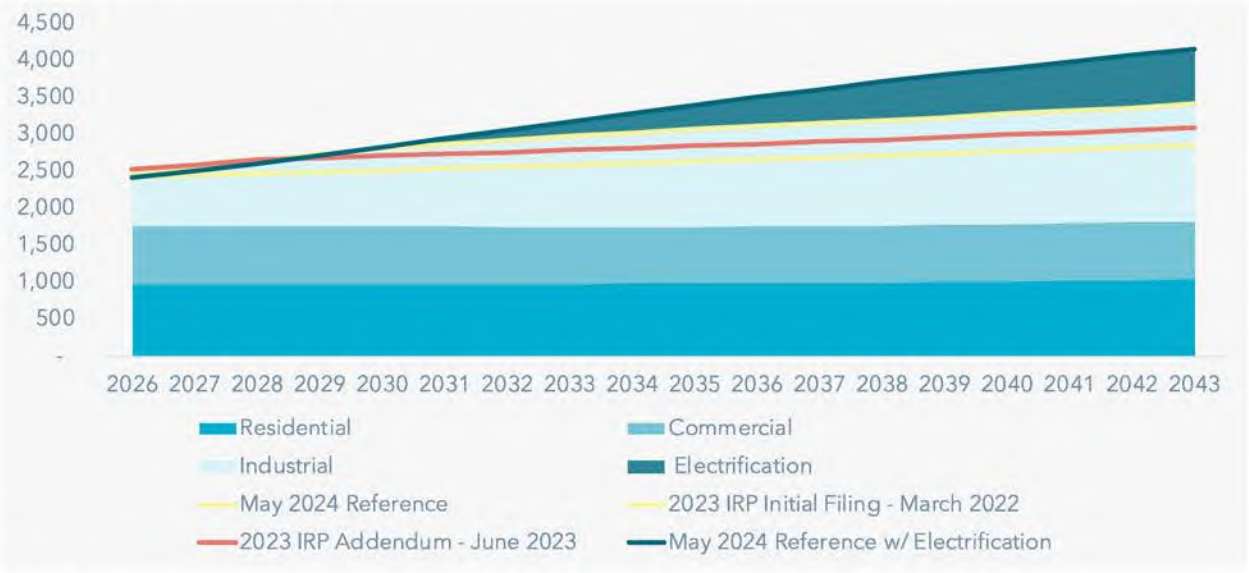


Table 7 presents a tabular growth rate summary comparison of the forecast vintages.

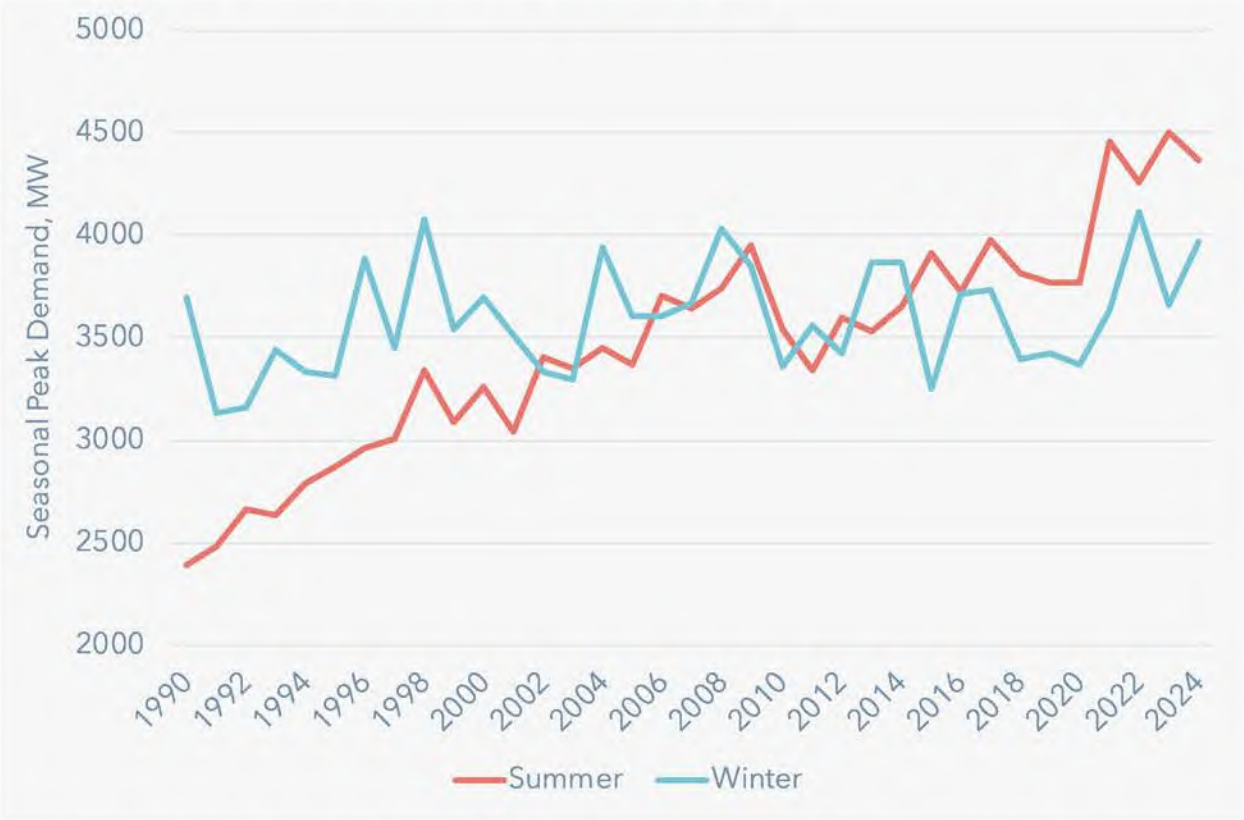
Table 7. Twenty-year average annual growth rates

	2023 CEP/IRP (March 2022)	2023 CEP/IRP Addendum (June 2023)	May 2024 Reference	May 2024 Reference + Electrification
Total Energy	1.2%	1.6%	1.9%	2.8%
Residential	0.5%	0.6%	0.4%	2.2%
Commercial	0.0%	0.0%	-0.1%	1.1%
Industrial	3.5%	3.9%	5.1%	5.2%

3.1.2 Seasonal peak demand forecast

In addition to increased industrial deliveries, PGE has also experienced persistent increases in its summer system peak demand. **Figure 15** presents the historical net system peak demand for the PGE service area from 1990-2024 for both the winter and summer seasons.

Figure 15. Actual seasonal net system peak demand, in MW



Recent events, such as wildfire smoke in 2020, the heat dome of 2021, increased AC saturations, and the rise in work-from-home have led to shifts in the utilization of home cooling systems.

To address these trends, PGE updated the peak demand forecast methodology. In addition to capturing recent trends, this methodology also allows for changes in load shape as the industrial class grows at an accelerated rate.

3.1.2.1 Peak Forecast Methodological Changes

In the 2023 CEP/IRP, PGE utilized a monthly regression model that related the single-hour peak demand to average monthly demand. This model trained with one observation per month, using historical data back to 2000. This resulted in few observations for training a summer peak event given the short nature of Oregon's summers. Further, these training observations reflected periods in time where the saturation and utilization of air conditioning in the home was less prevalent. Using this method, the temperature inputs used to forecast seasonal peak demand were based on a simple average of 15 years of peak day events.

For the May 2024 forecast, PGE updated its peak demand model with a focus on better capturing recent response to warm summer temperatures. The updated peak demand model uses hourly data by customer class – residential, commercial, and industrial – for 2019-2023 to better capture current usage trends during peak events. By using hourly data, the training set includes more cooling and heating events and can better capture the impact of weather on usage. The fixed effect model includes various weather variables, rooftop solar capacity, and

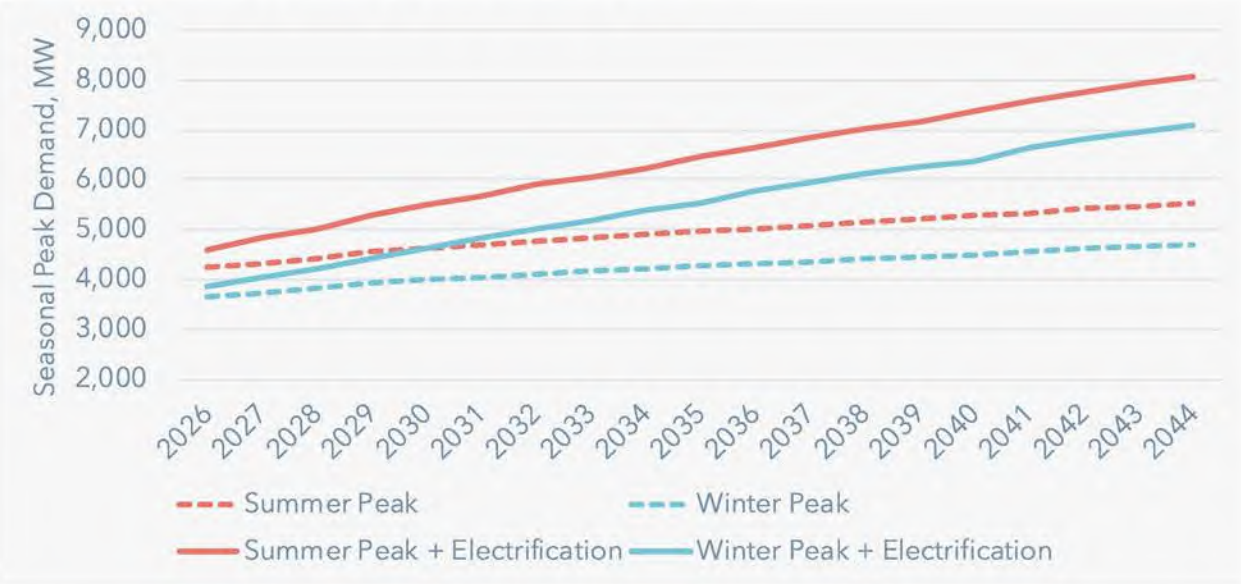
indicator variables to control for monthly, day of the week, extreme weather and COVID-19 impacts as explanatory variables.[43]

To develop the peak demand forecast, weather year simulations are created using historical hourly weather data for the period 2008-2023 with shifted day of week start to reflect 105 total simulations. These simulations are scaled by class to the average monthly energy forecast to capture growth. The expected seasonal peaks reflect the average system peak across the simulations in the given season. Probabilistic outputs were also created based on the standard deviation of simulated peak. This approach allows for data to feed directly into the Sequoia model, as described in **Section 3.4.2 Changes to modeling capacity need**.

3.1.2.2 Resulting Peak Forecast

PGE's base forecast average growth rate over the next 20 years is forecasted to be 1.5 percent for the summer peak and 1.4 percent for the winter peak, as shown in **Table 8**. After including the peak load impacts of electrification, average growth rates increase to 3.3 percent and 3.4 percent for summer and winter, respectively. **Figure 16** shows the trajectory of PGE's forecasted seasonal peak demand forecasts for the summer and winter seasons with and without electrification.

Figure 16. Forecasted seasonal peak demand, in MW



3.1.2.3 Peak High and Low Forecasts

PGE creates a high and low peak forecasts that correspond with the high and low load forecasts. In each scenario, the growth is front weighted to the five-year horizon, corresponding with the higher forecasted growth rate in the short-term. **Table 8** shows a comparison of the growth rate

[43] Weather variables include heating degree hours (HDH), cooling degree hours (CDH), and lagged HDH and CDH. HDH and CDH were calculated based using the observed temperature at each hour compared to a set base temperature (such as 65°F) with HDH being total degrees below set point and CDH being total degrees above.

of seasonal peak demand across the reference, high and low load forecasts both with and without the effects of electrification.

Table 8. Forecast twenty-year average growth rates

	High		Reference		Low	
	Base	Base + Electrification	Base	Base + Electrification	Base	Base + Electrification
Summer Peak	2.6%	4.2%	1.5%	3.3%	0.4%	1.8%
Winter Peak	2.5%	4.4%	1.4%	3.4%	0.3%	2.0%

3.1.2.4 IRP Update Comparison to Previous Filings

The May 2024 update reflected an increase in the peak forecast for both the summer and winter peak.[44] This increase is driven by the increased forecasted load growth as well as the updated methodology described in **Section 3.1.2.1 Peak Forecast Methodological Changes**. Though the peak forecasted growth rate has increased, it remains lower than the forecasted energy annual growth rate. **Table 9** shows a comparison of the growth rate of seasonal peak demand across the forecast vintages, including effects from electrification as estimated in AdopDER.

Table 9. Forecast peak 19 year (2026-2044) average annual growth rates

	2023 CEP/IRP (March 2022)	2023 CEP/IRP Addendum (June 2023)	May 2024 Reference	May 2024 Reference + Electrification
Summer Peak	0.7%	0.9%	1.5%	3.2%
Winter Peak	0.7%	0.8%	1.4%	3.5%

3.1.3 Load forecasts – excluding large customer load

To provide transparency into the drivers of PGE's resource need, additional analysis was performed to disaggregate large industrial load from PGE's forecast. As described in **Section 3.1.1.2 Large customer forecast**, semiconductor and data center loads are responsible for significant increases in PGE's forecast.[45]

3.1.3.1 Methodology: Excluding load from large customers

PGE's econometric load forecast methodology includes three core modeling elements: a monthly forecast of energy deliveries by rate schedule, a monthly forecast of large customer

[44] May 2024 Load Forecast Update discussed in Jul. 11, 2024 CEP/IRP Roundtable 24-3

[45] Similar segmentation was not performed in PGE's AdopDER model for electrification forecasts. It is assumed that all electrification in the industrial segment is associated to non-large customer projects.

usage, and an hourly simulation which creates the peak demand output. To isolate the impact of growth from large industrial load, PGE focuses on the large customer forecast, holding all customers who are projected to add at least 30 MW of load in coming years at levels consistent with PGE's forecasted values for 2025. This categorization by size is consistent with Category 3 large non-residential customers in PGE's proposed modification to its tariff filed in Advice No. 24-38/UE 430.

This approach does not attempt to capture the nuance associated with timing of individual customer load growth but instead selects a point in time and illustrates the magnitude of forecasted growth associated with large customer projects thereafter based on PGE's May 2024 Reference case Load Forecast.[46]

3.1.3.2 Resulting forecast – excluding large customer load

Removing growth associated with large customer load after 2025 results in lower energy deliveries and seasonal peak demand forecasts. The twenty-year average annual growth rate for the May 2024 Reference total energy forecast is estimated to reduce from 1.9 percent to 0.1 percent, prior to electrification. After including electrification, forecasts that exclude large customer load estimate a 1.3 percentage point reduction in the total energy twenty-year average annual growth rate, as shown in **Table 10**.

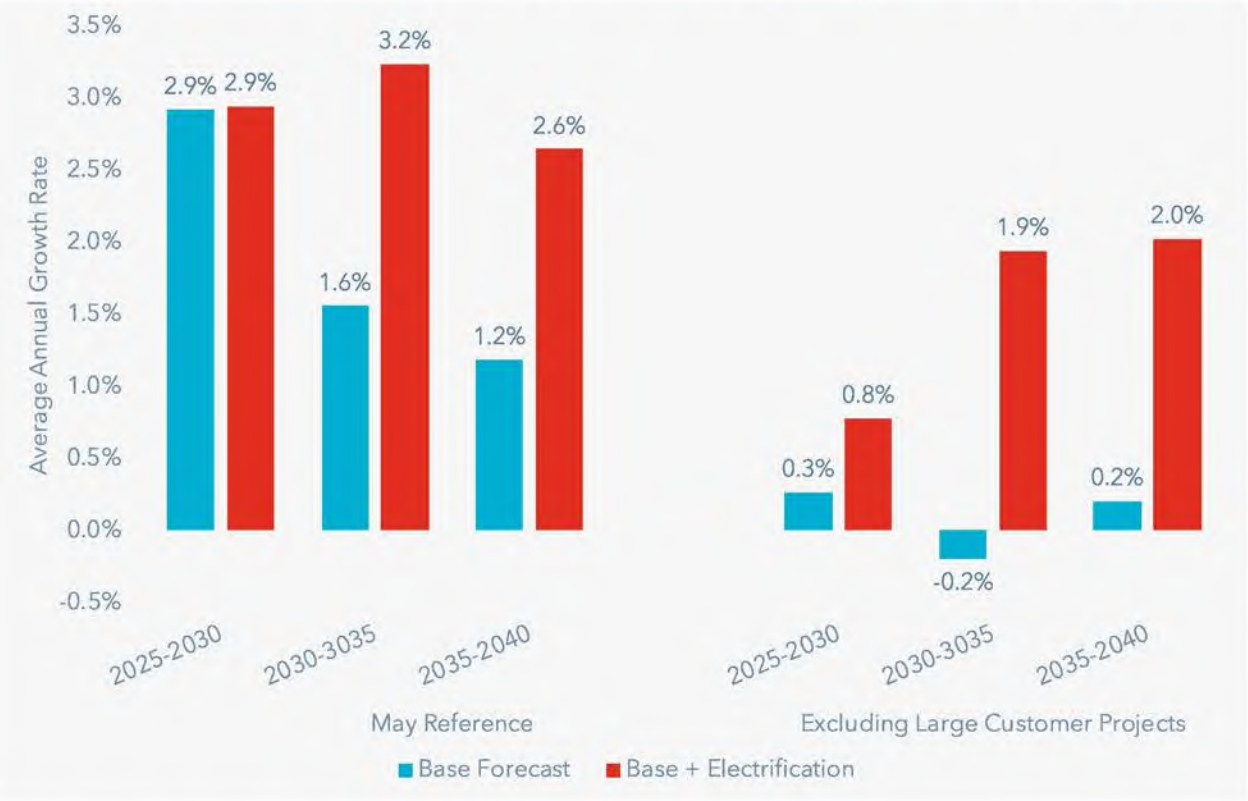
Table 10. Twenty-year average annual growth rate comparison, Excluding Large Customer Projects

	May 2024 Reference	May 2024 Reference + Electrification	May 2024 Reference, Excluding Large Customer Projects	May 2024 Reference + Electrification, Excluding Large Customer Projects
Total Energy	1.9%	2.8%	0.1%	1.5%
Summer Peak	1.5%	3.2%	0.3%	2.3%
Winter Peak	1.4%	3.5%	0.2%	2.5%

The reductions in load estimates from forecasts that exclude large customer load is greatest in the near term where line of sight to large customer load is most certain and growth is expected to be greater. **Figure 17** compares the five-year average annual growth rates consistent with the May 2024 Reference load forecast and the forecast which excludes large customer load, with and without electrification. These estimates suggest large customer load comprises the majority of PGE growth prior to 2030, after which electrification in the residential and commercial segments begins to account for an increasing share of forecasted growth.

[46] This methodology is forward looking and does not differentiate existing large loads.

Figure 17. Comparison of annual average growth rates for energy forecast at 5-year increments



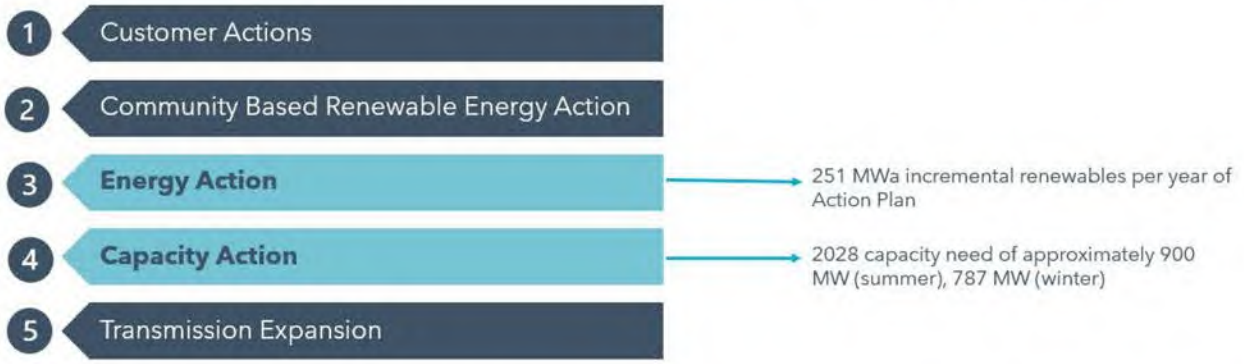
3.2 2023 RFP results

3.2.1 Target and need

In the 2023 RFP, PGE pursued non-emitting resources to facilitate a reliable energy supply for the service area while reducing the greenhouse gas emissions associated with energy generated to serve customers. PGE's 2023 CEP/IRP found that the company has a need for additional capacity resources beginning in 2026, with an additional capacity need in 2028. Further, the 2023 CEP/IRP Action Plan identified that procuring additional energy resources is needed to support the reduction of greenhouse gas emissions within PGE's portfolio. The 2023 RFP was designed and approved, subject to conditions, to seek resources to address these needs within a 2025-2027 commercial online date (COD) window, consistent with PGE's 2023 CEP/IRP Action Plan.[47] PGE's 2023 CEP/IRP Action Plan items are shown in **Figure 18**, with the targets for energy and capacity actions targeted by the 2023 RFP shown in light blue.

[47] See Order No. 24-011, as modified by Order Nos. 24-024 and 24-085.

Figure 18. PGE's 2023 CEP/IRP Action Plan, and associated targets for 2023 RFP[48]



As shown above, the 2023 CEP/IRP Action Plan included both a capacity and energy action: the capacity action identified a need in 2028 of 905 MW in summer and 787 MW in winter.[49] The response from the market to the 2023 CEP/RFP was robust, and PGE's final shortlist included 361 MW of capacity contribution from renewable resources, plus an additional 695 MW of capacity contribution from dispatchable capacity options in the form of lithium-ion battery storage. In the RFP, PGE sought the identified capacity needs entirely from non-emitting resources and has identified resources which, after contemplating the latest IRP capacity modeling updates, reduce PGE's 2028 capacity need to 0 MW and 195 MW for summer and winter, respectively. Because negotiations are ongoing, there is still uncertainty in which resources will become part of PGE's portfolio.

PGE evaluated the costs, risks, and benefits of renewable procurement volumes to make progress toward the identified energy action outlined in PGE's 2023 CEP/IRP Action Plan. While PGE saw a robust response to the 2023 RFP, the total number of renewable energy resources recommended for procurement based on customer value was not sufficient to fully address PGE's 2025-2027 energy action as described in the Action Plan in the 2023 CEP/IRP. Where the 2023 CEP/IRP recommended 753 MWa of renewable energy acquisition, the total generation available from of renewable options on PGE's initial shortlist for this RFP was approximately 350 MWa. PGE's final shortlist Group A, which identified 96 MWa of renewable energy resources and 775 MW of lithium-ion batteries, and Group B, which identified 885 MW of lithium-ion batteries, included projects that are likely to represent least-cost, least-risk for customers.[50] PGE continues to negotiate with the remaining Group A projects and aims to finalize contracts over the course of 2025.

PGE did not include four unique renewable projects on the final shortlist, which together represented an additional 1,000 MW of resources. The primary reason these projects were not included in the final shortlist was their anticipated impact to customer affordability. PGE is continuing to actively seek additional clean energy resources from the market that offer reliability

[48] See PGE's Request for Acknowledgment of the Final Shortlist of Bidders, p. 5
[49] See PGE Response to Staff's Round 2 Comments and Recommendations, p.42
[50] On December 12, 2024, one of the projects in Group A notified PGE that it was withdrawing from commercial negotiations.

and efficiency at the lowest costs to customers. PGE is currently advancing the 2025 All-Source RFP to seek additional non-emitting energy and capacity resources. PGE plans to issue the RFP to the market in the third quarter 2025 and compile a final shortlist in early 2026.[51]

3.2.2 2023 RFP proxy

On November 25, 2024, the OPUC acknowledged, subject to conditions, PGE's 2023 RFP final shortlist of bids.[52] PGE commenced commercial negotiations to acquire resources from the final shortlist Group A.[53] The final shortlist Group A consists of four projects with the following general characteristics:

1. Hybrid 250 MW solar & 250 MW battery
2. Hybrid 125 MW solar & 125 MW battery
3. Standalone 400 MW battery
4. Standalone 41 MW solar

Because negotiations for project acquisition are ongoing, there is still uncertainty in which resources will become part of PGE's portfolio. To account for the expected addition of resources to the portfolio, PGE's models include a proxy set of resources that represents an informed estimate of the quantity of resource acquisitions from the 2023 RFP. The RFP proxy serves as a placeholder for the resources in PGE's modeled portfolio.

The RFP proxy represents the energy and capacity benefits contributed to PGE's portfolio by the expected resources from the final shortlist so they can be accounted for in calculation of energy need, capacity need, and proxy resource ELCCs. The RFP proxy used in IRP Update modeling consists of 375 MW of solar/battery hybrid resources and 400 MW of standalone 4-hr battery storage, representing Group A resources.[54] Since identifying the resources in the final shortlist Group A, the 41 MW standalone solar project withdrew from commercial negotiations and energy and capacity are not included in the RFP proxy.[55] Subsequent to the final definition of modeling assumptions in the Update, the 250 MW solar & 250 MW battery hybrid project also withdrew from commercial negotiations. Because modeling was already underway, the energy and capacity of the 250 MW solar & 250 MW battery hybrid is included in the RFP proxy. The updated needs in 2028 with the inclusion of the RFP Proxy are 0 MW and 195 MW for summer and winter, respectively.

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[51] Docket No: UM 2371
[52] OPUC Docket No. UM 2274 Final Order available here: https://apps.puc.state.or.us/orders/2024ords/24-425.pdf
[53] The shortlist is bifurcated into an A group and a B group of resources. The RFP proxy is based on the resources in group A only and references to the final shortlist in this section refer to group A resources only. PGE's decision on whether to pursue group B bids will depend upon the outcomes of commercial negotiations for group A bids.
[54] Final shortlist Group B resources are not included in the RFP proxy.
[55] On December 12, 2024, the 41 MW standalone solar project notified PGE that it was withdrawing from commercial negotiations.

3.3 Energy need

Energy need is the difference between PGE's forecasted load (demand) and the supply of energy available to serve load from existing owned and contracted resources in the baseline portfolio, defined in terms of average Megawatts (MWa). Energy need is an important input to portfolio analysis as one of the main drivers of the need for new resource additions. This section describes the energy need forecast used for portfolio analysis, calculated with the most up to date information available at the time of analysis.

PGE presented an annual energy position forecast in the 2023 CEP/IRP and subsequently updated it in the 2023 CEP/IRP Addendum.[56] The Addendum incorporated an updated load forecast and changes to the baseline portfolio that occurred after the writing of the 2023 CEP/IRP. The net effect of updates made to the annual energy position from the 2023 CEP/IRP to the Addendum were to increase PGE's energy need.

PGE has incorporated additional updates into modeling since the Addendum, which has led to another update to PGE's forecasted energy need. Modeling updates incorporated into IRP Update that impact annual energy need include an updated load forecast (**Section 3.1 Econometric load forecast**), updated forecasts of cost-effective DERs (**Section 5.2.1 Passive DERs**) and EE (**Section 5.3 Energy efficiency**), and updates to PGE's baseline resource portfolio. The load forecast used in the Update includes higher energy demand compared to the forecast from the IRP Addendum. Updated forecasts of cost-effective DERs and EE have increased since the IRP Addendum. These resources offset energy usage and reduce the quantity of load to be served, decreasing annual energy load resource balance.

Updates to the baseline portfolio since the Addendum include the RFP proxy, the addition of new contracts and an updated Qualifying Facilities (QF) forecast. The three new hydro contracts in the base portfolio include one with Grant PUD from 2024-2026 and two with Douglas PUD, one spanning 2024-2025 and one from 2026-2030.[57] Additionally, included in this update is a new contract with Calpine for a 250 MW share of the Hermiston combined-cycle natural gas plant in Hermiston, OR from 2025 through 2029.[58] Baseline portfolio updates have increased the quantity of energy in PGE's portfolio, decreasing annual energy need.

The incremental impact of each of the updates and resulting 2030 Reference Case needs are shown in **Figure 19**. In 2030, the increase in annual energy in PGE's baseline portfolio and increased EE and DERs outweigh the increased need associated with the new load forecast and other modeling updates, resulting in a decrease in PGE's annual energy load-resource balance from 1307 MWa to 1204 MWa. PGE's annual energy load-resource balance, including Reference, Low, and High need futures, is shown for the 20-year planning horizon in **Figure 20**.

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[56] 2023 CEP/IRP and Addendum to the 2023 CEP/IRP

[57] Hydro contract details available in PGE 2024 10k filing, page 15.

[58] Consistent with the methodology used in the 2023 CEP/IRP, the quantity of emitting energy retained to serve PGE's load is limited to quantities that are compliant with HB 2021 GHG emissions targets based on the linear GHG reduction glidepath. The quantity of energy retained from the Calpine project is determined by the IGHG model. The impact of Calpine on PGE's retained quantity of emitting energy is described in **Section 3.5.1 HB 2021**.

Figure 19. Incremental impacts of updates on 2030 Reference Case energy need

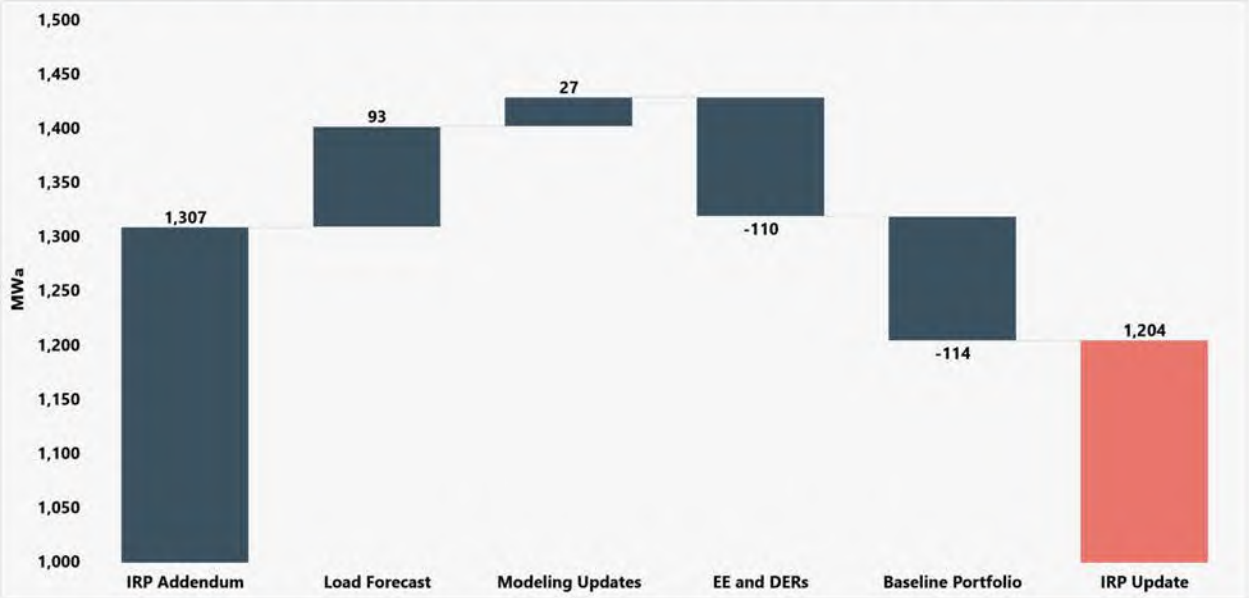
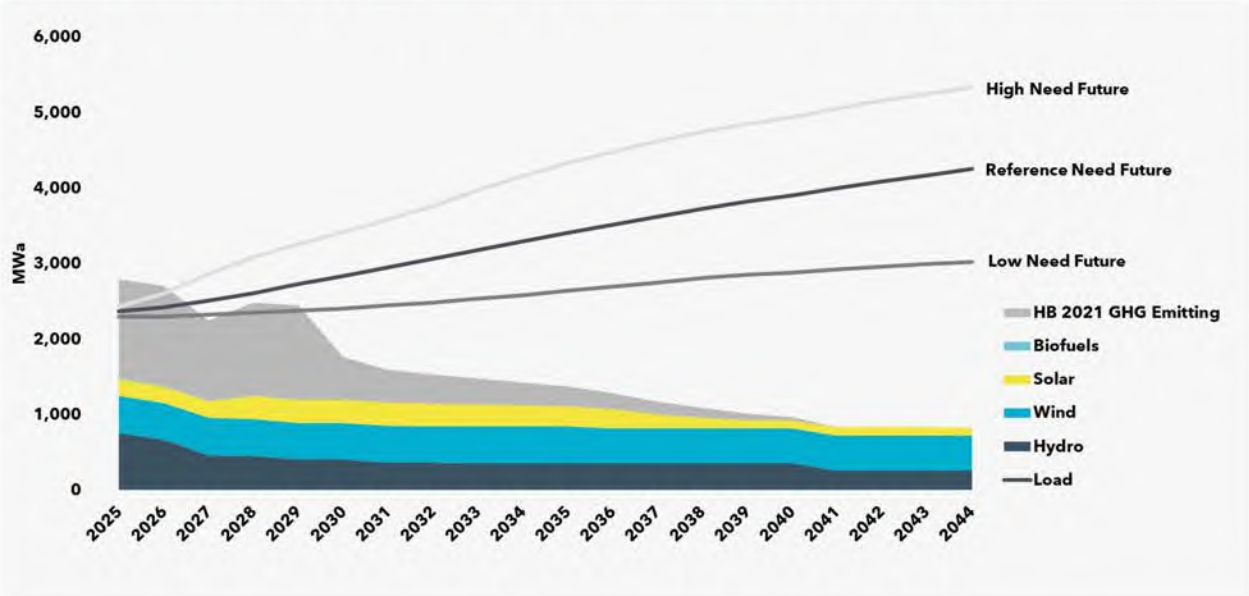


Figure 20. Annual energy-load resource balance from 2025 through 2044

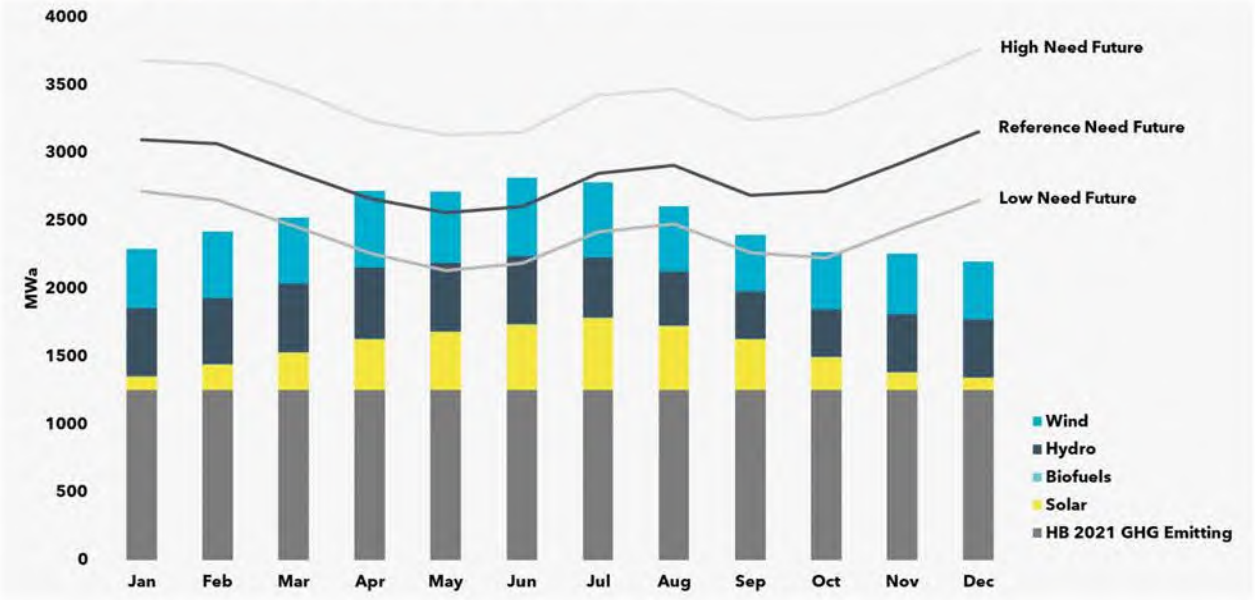


The gap between load and the stacked area of annual energy from PGE's baseline portfolio retained to serve retail load under HB 2021-compliant assumptions in **Figure 20** represents the minimum energy need remaining to be filled by incremental resource additions in portfolio analysis. For this Update PGE has calculated a monthly energy-load resource balance to further inform the magnitude of PGE's energy need. Because load and energy generation from renewable resources are both influenced by weather and the presence or absence of sunshine and wind, there are distinct seasonal patterns to energy supply and demand. PGE's load tends to

peak in the summer and winter when temperatures are very hot or cold and is lower during the mild temperatures of the spring and fall. Solar facilities produce the most energy in the summer and the least in the winter. Patterns of wind production are less predictable than solar but still display seasonality that varies by location. On average, the wind in PGE's baseline portfolio tends to produce the most in the spring and early summer. Hydro generation is also seasonal, with peak generation coinciding with spring runoff.

These dynamics in load and expected resource generation are shown for 2028 in **Figure 21**. The quantity of energy from renewable resources is calculated using monthly average capacity factors, which represents the percent of the time that a facility is expected to be generating throughout any given month. Energy from dispatchable sources cannot be allocated using static average capacity factors like non-dispatchable resources because the timing of their generation is determined by economic and operational decision making, so in **Figure 21** they are depicted as flat across each month of the year.[59]

Figure 21. 2028 monthly load-resource balance

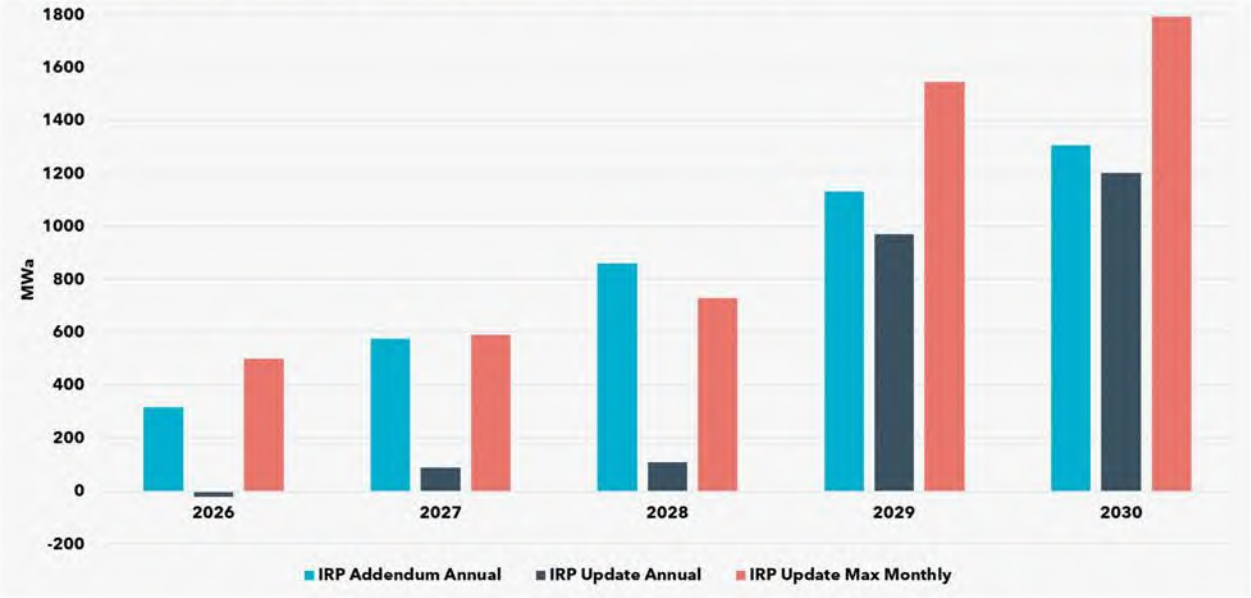


Seasonal dynamics can have important implications for resource planning and influence the optimal quantity and mix of resources in the portfolio. The magnitude of energy need in a given month may exceed the energy need on average across the year, increasing the quantity of resources needed. The timing of energy need throughout the year may be more correlated with some resource options than others, impacting which resources most optimally meet energy needs. Monthly energy-load resource balance accounting enables PGE to capture and consider seasonal variations in resource planning.

[59] The monthly allocation of energy from dispatchable sources is accounted for in portfolio analysis and is discussed in **Section 6.1.2 Energy need**.

The Update relies upon monthly energy needs to inform portfolio analysis. Resources are added to portfolios to ensure that each portfolio is forecasted to achieve monthly energy load resource balance. **Figure 22** compares PGE's annual energy load resource balance to the monthly energy load resource balance that is incorporated into PGE's portfolio analysis. Consistent with the above figure, this comparison assumes that energy from dispatchable sources is evenly distributed throughout the year, while PGE's portfolio analysis methodology allows dispatchable energy to be allocated throughout the year to minimize maximum monthly energy needs consistent with comprehensive portfolio economics. PGE's choice of incorporating monthly energy needs into portfolio analysis is responsive to Staff's condition, adopted by the OPUC in the 2023 CEP/IRP which expressed concern the previous filings reliance on annual energy metrics to demonstrate continual progress toward PGE's HB 2021 emissions targets.[60] By incorporating monthly energy needs into portfolio analysis, PGE's IRP Update better represents the seasonal aspects of PGE's decarbonized energy needs. Additional analysis which directly assesses the ability of the Preferred Portfolio to meet emissions targets on at an hourly granularity is discussed in **Section 6.2.2 Hourly energy and emissions accounting results**.

Figure 22. Comparison of Annual to Monthly Energy Need



3.4 Capacity need

Capacity need estimates the effective capacity, expressed in MW, required to achieve a resource-adequate portfolio. These estimates come from PGE's resource adequacy model, Sequoia. Sequoia estimates capacity need under a "1 day in 10 years" reliability metric, interpreted as 2.4 loss of load hours (LOLH) annually. PGE first developed Sequoia during the

[60] Staff Recommendation #3 from IRP Acknowledgement Order 24-096. Available here: https://apps.puc.state.or.us/orders/2024ords/24-096.pdf

2019 IRP Update.[61] The following section discusses the 2023 CEP/IRP Update need across the planning horizon, describes the effect of model updates made since PGE's CEP/IRP Addendum: System Need & Portfolio Refresh, and compares capacity need across different need futures that capture supply and demand uncertainty.

3.4.1 Seasonal need – reference case

The 2023 CEP/IRP Update estimates capacity need in summer (April-September) and winter (October-March). **Figure 23** shows PGE's seasonal capacity need across the 20-year planning horizon compared to capacity need previously estimated in Addendum filing.[62] PGE's near-term capacity need decreased since the addendum because of supply side additions, namely bilateral contracts, and resource additions modeled by the RFP Proxy. The updated summer capacity need is estimated at 47 MW in 2026. This capacity need grows to 485 MW in 2027 with the expiration of Grant PUD hydro contracts, then drops to 0 MW in 2028 as RFP Proxy Resources enter the modeled supply stack. In 2027, a winter capacity need of 159 MW is estimated and is expected to continuously grow.

PGE notes sources of uncertainty in short-term capacity need estimates. PGE's Econometric Load Forecast represent average expected outcomes and include a range of possible values. The 2023 CEP/IRP Update represents uncertainty in load forecasts by modeling different need futures, which could decrease or increase short-term need significantly (**Figure 23**). Another source of uncertainty relates to PGE's supply portfolio. Absent executed agreements, the 2023 CEP/IRP Update includes RFP Proxy resources assuming a January 1, 2028 commercial operations date. Resources may reach commercial operations before or after the assumed date. PGE can address remaining short-term need through commercial agreements to access existing resources. Structured or bilateral contracts can be agreed upon to provide capacity from existing resources. Additionally, regional sharing mechanisms from state resource adequacy requirements may provide additional capacity.[63]

Looking beyond the short-term, capacity needs in both seasons increase significantly in 2030 due to the exit of Colstrip and expiration of the Calpine contract. Capacity need grows steadily until 2040 where it is assumed all gas plants exit the portfolio, resulting in an approximately 2 GW increase in need.[64]

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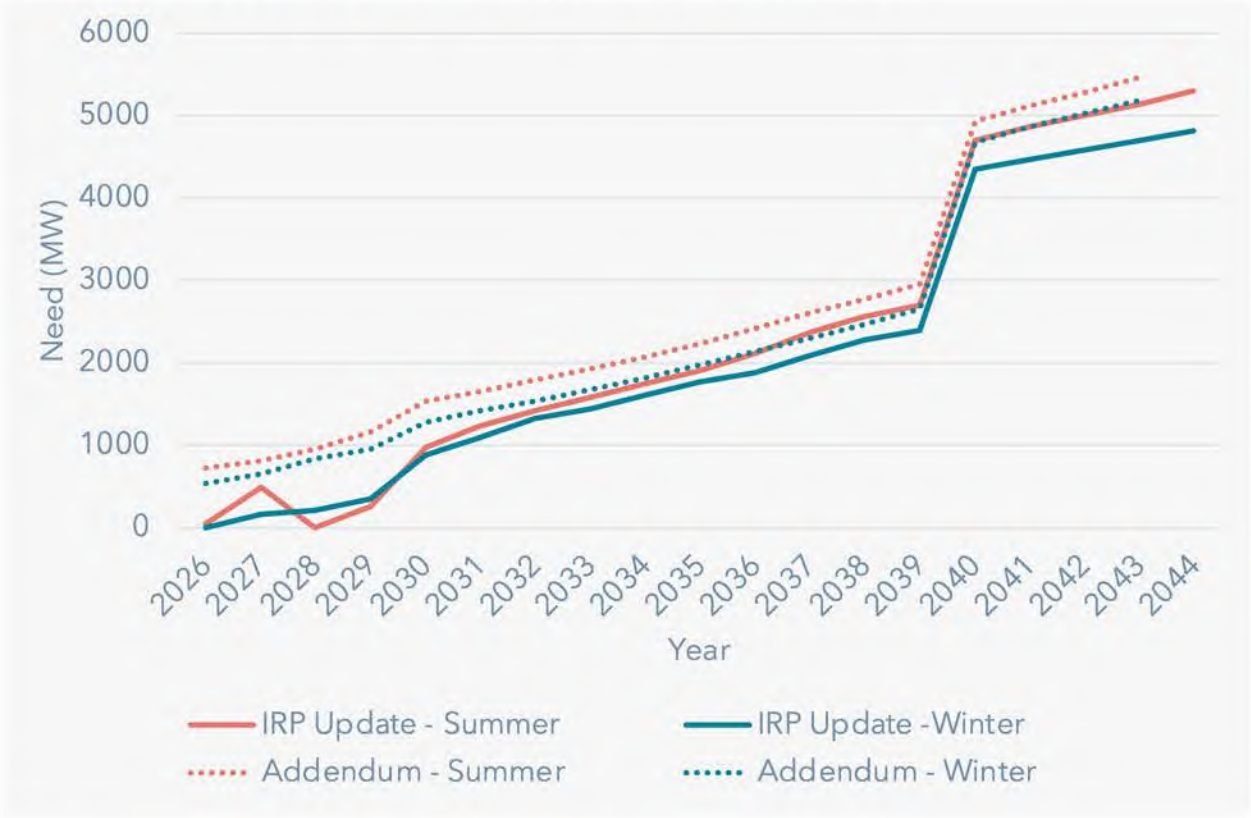
[61] The following resources provide descriptions of Sequoia from past roundtables and filings: 2019 IRP Update Sequoia overview - Appendix K; 2023 CEP/IRP Sequoia overview – Appendix H.3; May 2021 CEP/IRP Roundtable; March 2022 CEP/IRP Roundtable; January 2023 CEP/IRP Roundtable; August 2024 CEP/IRP Roundtable

[62] PGE's 2023 CEP/IRP Addendum: System Need & Portfolio Refresh

[63] OPUC Docket AR 660 – Resource Adequacy Rules

[64] Due to infeasibility of model solutions in Sequoia for years with a very high need and little dispatchable resources, out of model adjustments were made to extrapolate latter years in the planning horizon. Infeasible years for the reference and high need futures are 2041-2044, and 2044 for the low need future. The average annual growth rate of need for 3 years prior to the greatest feasible year for each season and need future are used to extrapolate need. The average annual growth rate used to extrapolate need is approximately 8%, 6% and 4% for reference, high and low need futures, respectively.

Figure 23. 2023 CEP/IRP Update Capacity Need - Reference Case



3.4.2 Changes to modeling capacity need

The 2023 CEP/IRP Update includes multiple changes to Sequoia as part of refreshing PGE's capacity need estimates. The updates include methodological and other input related changes that aim to improve the representation of Sequoia's assessment of demand and supply in PGE's system. **Figure 24** and **Figure 25** display the incremental effect of major updates affecting PGE's capacity need estimates for both summer and winter, respectively. The incremental changes in capacity need depicted depend on the order in which updates are sequenced, while the final capacity need does not.[65] Updates were ordered to show methodological effects first, followed by changes in input assumptions. Updated capacity need in 2028 shows a net decrease for both summer and winter.

3.4.2.1 Updated analysis period

As part of the 2023 CEP/IRP Update, Sequoia was updated to allow modeling of the most recent 30 years of historical load and generation data, shifting the analysis period from 1992-2021 to 1994-2023. This shift in analysis period allows Sequoia to model more recent weather effects on

[65] For example, the 155 MW increase and 57 MW decrease of summer and winter capacity need resulting from Load Updates, respectively, are relative to the changes which resulted from the "Updated Analysis Period" vintage of Sequoia modeled prior. Reordering these changes would not alter the 0 MW summer and 195 MW winter capacity needs for 2028.

load and variable energy resources. This change in methodology results in a 46 MW increase in summer need and 14 MW increase in winter need.[66]

3.4.2.2 Load forecast updates

Two updates to load forecasts used in Sequoia are included in the 2023 CEP/IRP Update. First, PGE's Corporate Load Forecasts (CLF) hourly historical simulation is used in place of the previous historical simulation. Second, the load forecast version is updated from May 2023 to May 2024. As part of the 2023 CEP/IRP Update, PGE's CLF developed a historical simulation of hourly load (**Section 3.1 Econometric load forecast**). This simulation replaced the previous approach which scaled historical weather-dependent load to approximate forecasted monthly peak and average energy for future years. Scaling the weather-dependent load shape required a linear estimation which aimed to represent future load shapes, a process which was less precise and irreproducible iteration-to-iteration. The new CLF approach produces the hourly historical simulation necessary for Sequoia, resulting in a more efficient and reproducible method. Lastly, forecasts used to estimate load were updated from May 2023 to May 2024. In total, these load forecast updates result in a 57 MW decrease in winter capacity need and a 155 MW increase in summer capacity need for 2028.

3.4.2.3 Supply-side updates

The various supply-side updates that are part of the 2023 CEP/IRP Update (**Section 3.3 Energy need**), resulted in a 313 MW, 218 MW and 615 MW reduction in summer need for new contracts in the base portfolio, revised DER estimates, and RFP Proxy Resources, respectively. In winter, the supply-side updates resulted in a 335 MW, 91MW and 162 MW reduction in capacity need from new contracts in the base portfolio, revised DER estimates, and RFP Proxy Resources, respectively.

[66] Reference **Appendix B Sequoia methodological update** for additional detail.

Figure 24. Incremental Changes to Capacity Need - Summer 2028 Reference Case

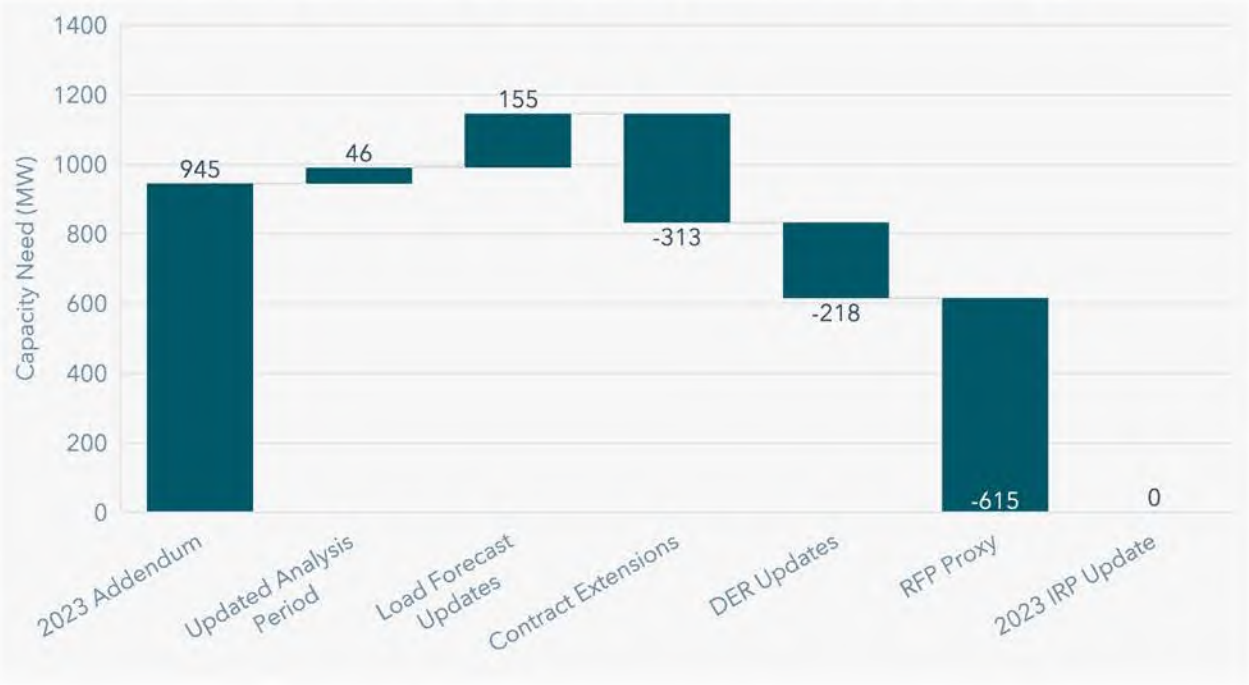
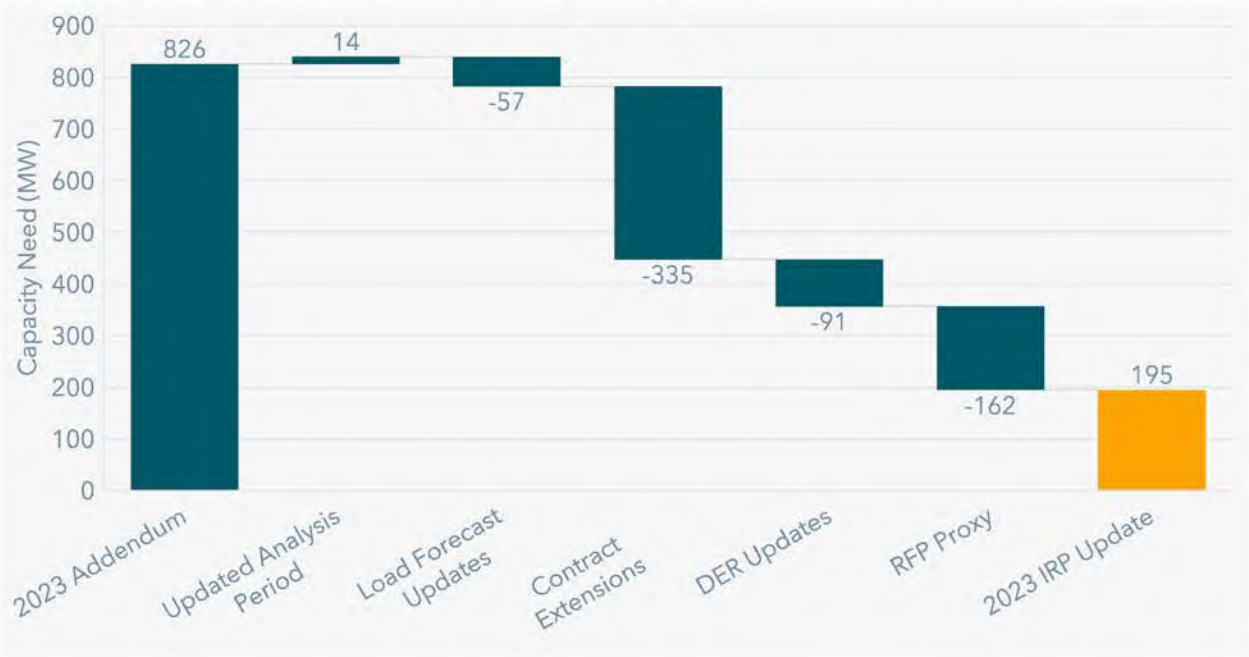


Figure 25. Incremental Changes to Capacity Need - Winter 2028 Reference Case

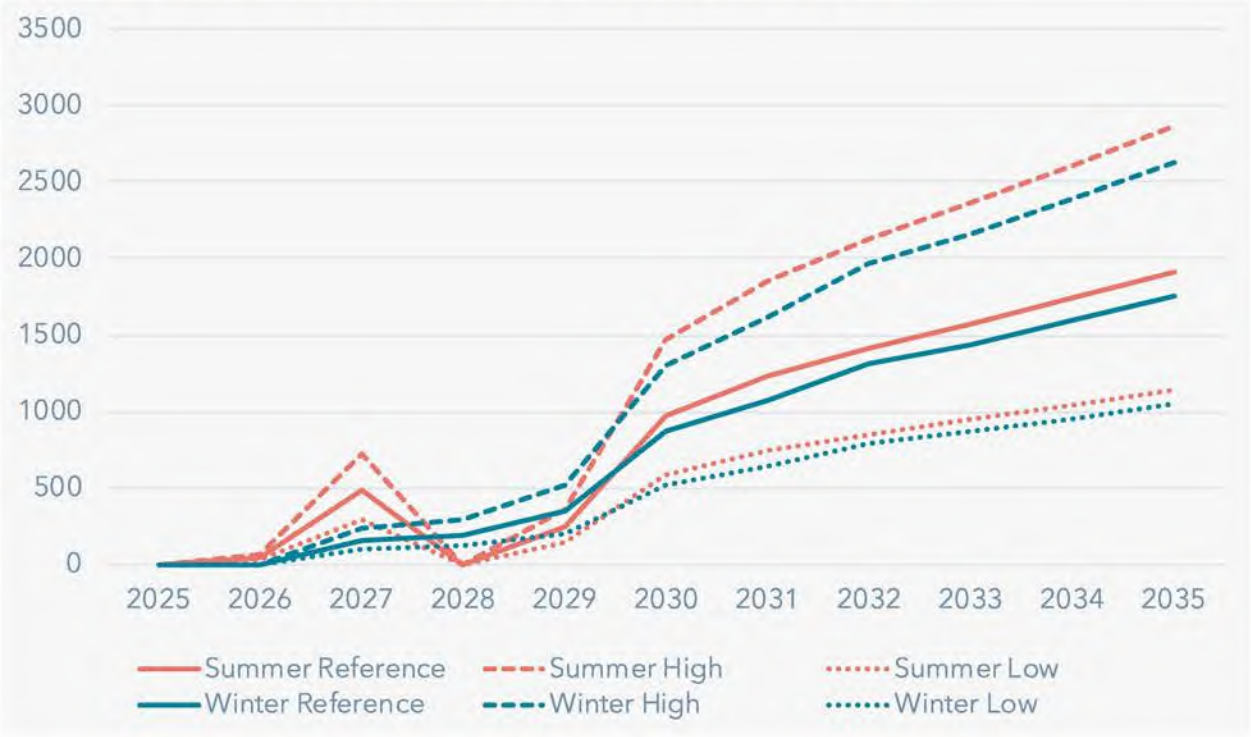


3.4.3 Capacity need under different futures

The 2023 CEP/IRP Update models capacity need across low and high need futures to capture uncertainty in both supply and demand side variables. **Figure 26** shows the capacity needs of the low and high need futures and the Reference Case. The figure suggests the different futures

approximate a uniform shift of reference case needs, resulting in 0 MW of need prior to 2030 in both seasons, except summer 2027. The high need future results in approximately 700 MW more need on average in each season for years 2030-2035.

Figure 26. Capacity need under different need futures: 2026-2035



3.5 State policy requirements

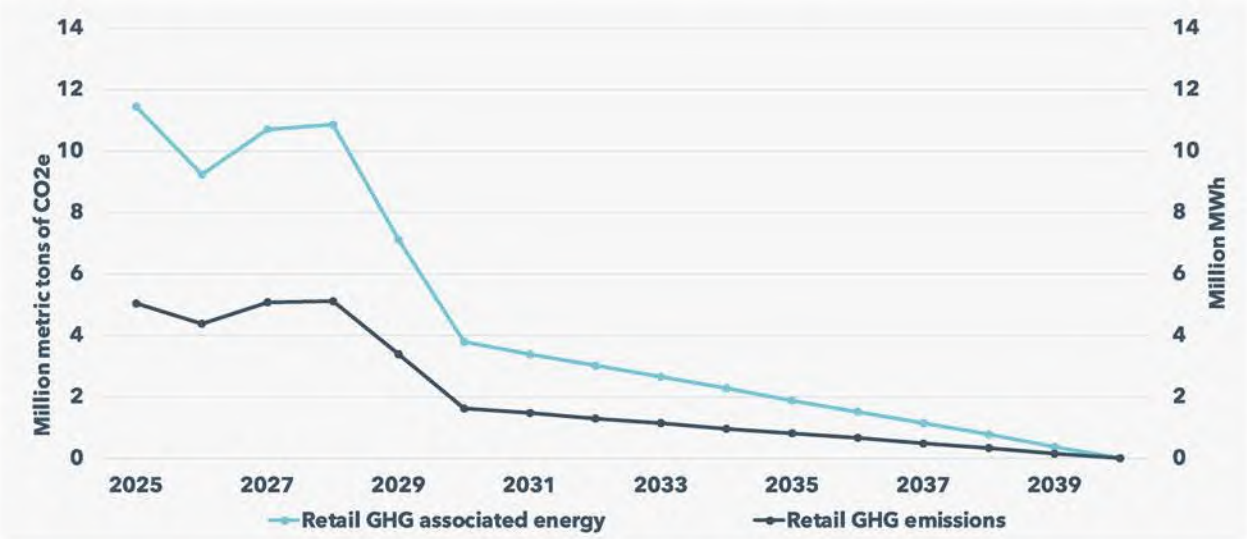
This section describes how State policy requirements are imposed through the utility regulatory framework and updates PGE made to reflect these constraints as part of the 2023 CEP/IRP Update.

3.5.1 HB 2021

The 2023 CEP/IRP was the first resource plan published by PGE that addressed the requirements of HB 2021. The emissions targets of HB 2021 remain unchanged from the 2023 CEP/IRP Update; compliance with these requirements is incorporated as the default assumption in modeling, including the creation of the Preferred Portfolio and the Action Plan. More details on modeling specifics can be found in those chapters of this document.

PGE continues to rely on a linear GHG reduction glidepath to inform the modeling as it was found to provide the best combination of cost, risk, and rate of emissions reduction amongst a variety of glidepaths tested in the Appendix I C-level analysis of the 2023 CEP/IRP. The impact of this glidepath is a limit of the thermal generation and market purchases with associated emissions retained for retail load. Updated data and analysis described in Chapter 3 inform an updated emission reduction glidepath presented in **Figure 27**.

Figure 27. GHG emissions & energy associated with serving Oregon retail load (Reference Case)



The 2023 RFP procurement results are not yet final but could add resources by the beginning of 2028. While further resource procurement will allow for more portfolio additions, these are unlikely to come online before the beginning of 2029 due to the time needed for procurement processes and construction timelines. Consequently, all current resources are necessary to meet demand and maintain reliability until 2029. Modeling does not include any additional non-emitting resources until the beginning of 2029 at the earliest. This situation limits the near-term emissions reductions achievable by PGE over the next three years. As a result, the updated emissions glidepath in the near-term reflects emissions levels more consistent with recent history given inability to alter the current generating mix prior to 2029.

PGE is accelerating procurement through RFPs between now and 2030. PGE has requested approval of its 2025 RFP in Docket UM 2371 to continue to seek resources to meet needs that remain after the conclusion of the 2023 RFP. Possible resource procurements from the 2025 RFP are presently unknown and therefore not included in this analysis.

Figure 28. Total (retail + wholesale) GHG emissions under the adjusted linear reduction glidepath (Reference Case)

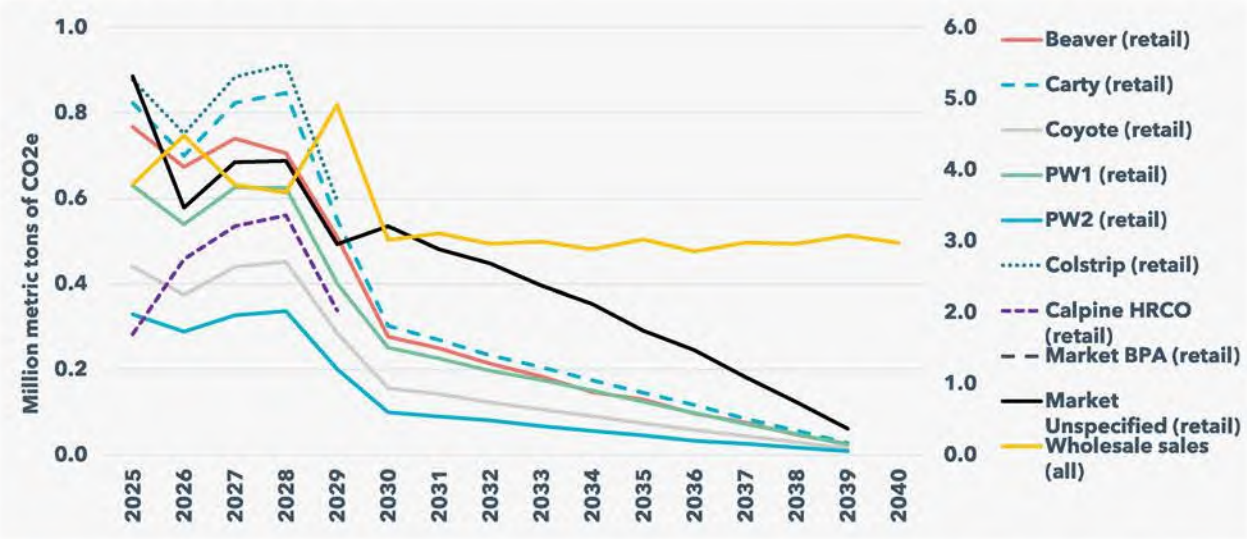


Figure 28 reflects GHG emissions projections from thermal generation and market purchases under the updated decarbonization glidepath. The lines specific to individual resources show retail GHG emissions. The specified wholesale sales category captures GHG emissions from sales from all sources not accounted for in retail sales that in the Update forecast support customer affordability through reduced net-variable power costs and reflect ongoing participation in the wholesale market to support reliability of the regional power system.

To achieve the HB 2021 emissions target in 2030, integration of non-emitting resources onto PGE's system will enable a systematic reduction in fossil fuels serving Oregon retail load and subsequent GHG reductions. As non-emitting energy and capacity resources are added, the amount of thermal output from natural gas and coal for Oregon retail load is reduced to meet the emissions targets. The market for thermal generation is increasingly constrained across the West, with clean energy or GHG requirements in place in almost every state in the Western Interconnection. Thermal generation sold into the Western Interconnection is therefore increasingly subject to the GHG or clean energy requirements of other states. For example, fossil fuel energy exported to California and Washington incurs direct carbon pricing obligations. These policies, and dramatic addition of non-emitting resources anticipated across the region, contribute to reducing the quantity of economically dispatched thermal output in PGE's forecasts.

3.5.2 RPS obligation

RPS requirements were included in the 2023 CEP/IRP and will continue to be accounted for in portfolio analysis in the 2023 CEP/IRP Update. PGE's RPS obligation, which is a function of the forecasted load, has been updated to reflect the updated load forecast used in the Update. Updated RPS requirements are shown in **Table 11**. The Preferred Portfolio's compliance with RPS requirements is demonstrated in **Section 6.2 Preferred Portfolio**.

Table 11. Updated RPS obligations Reference need future

Year	RPS requirement (% of retail sales)	RPS requirement (MWa)
2025	27%	482
2030	35%	748
2035	45%	1155
2040	50%	1470

This filing has not made any updates to assumptions regarding the Company's REC bank since the 2023 CEP/IRP. In Order No. 24-096, the OPUC directed PGE to provide a more detailed RPS analysis in the next CEP/IRP, and PGE intends to include this analysis and broader REC strategy in the 2026 plan.[67]

3.5.3 Small scale renewables standard

Following Commission direction, this Update will explicitly account for Oregon's small-scale renewable (SSR) requirement in its modeling.[68] The SSR requirement that, starting in 2030, 10 percent of aggregate electric capacity in PGE's portfolio be composed of renewable facilities 20 MW or smaller in size is incorporated into portfolio analysis. In this update, PGE has added a new constraint and a new SSR proxy resource option in ROSE-E to ensure that the Preferred Portfolio is compliant with SSR requirements. The SSR proxy resource option is described in **Section 5.4 SSR resource**. The quantity of resources forecasted to be required to meet the 10 percent requirement, which is dependent on the quantity of resources added in the Preferred Portfolio, is presented and discussed in **Section 6.4 Small scale renewables plan**.

[67] Direction for future planning on RECs can be found on page 22 of the final order, available at: https://apps.puc.state.or.us/orders/2024ords/24-096.pdf.
[68] The SSR requirement is included based on Commission direction in the LC 80 final order. See page 11 at: https://apps.puc.state.or.us/orders/2024ords/24-096.pdf.

Chapter 4. Transmission landscape

PGE owns transmission assets and holds transmission contract rights for reliable delivery of electricity from generation resources to load. Additional transmission rights will be required for PGE to access more diverse resources, decarbonize, and maintain adequacy. However, there is a limited amount of existing transmission available for future resources to use. This chapter provides an update on relevant evolving topics discussed more fully in the 2023 CEP/IRP and provides an overview of PGE's current transmission environment, projects in PGE's system planning, and options in IRP modeling.

Key Highlights

- The transmission system serving PGE customers is highly constrained, with limited existing transmission available for future resources, particularly on BPA's system which supports limited resource additions prior to further transmission upgrades.
- The North of Pearl (NOPE) flowgate has emerged as a significant constraint since August 2023, creating operational challenges that could be exacerbated by ongoing regional trends that are causing increasing south to north flows near Portland. Multiple projects are required to address reliability risks related to this flowgate.
- Transmission plays an essential role to access diverse generation resources that are unavailable within PGE's service territory. Several transmission projects in various stages of development have been identified to help PGE access new renewable resources from diverse geographic areas.

Developments Since 2023 IRP

This Update reflects significant developments in PGE's transmission planning since the 2023 CEP/IRP. The North of Pearl flowgate, which BPA established in August 2023, has created operational constraints during periods of renewable resource imports from California and the desert southwest across PGE's service territory. For the Bethel-Round Butte (also known as Warm Springs Power Pathway) project, PGE and the Confederated Tribes of Warm Springs have successfully secured a $250 million Grid Resilience and Innovation Partnerships (GRIP) Program grant, enabling survey work to begin. PGE has further refined additional transmission options in the modeling based on third-party analyses from Energy Strategies and Energy GPS, reflecting more realistic estimates of project timelines, achievable capacity, and market access benefits.

Strategic Implications

These changes highlight the growing urgency of PGE's transmission needs as the company works toward decarbonization goals while facing increasing load growth and system constraints. The emergence of the North of Pearl flowgate creates new operational challenges that will require collaborative solutions with BPA. The GRIP funding for the Bethel-Round Butte project improves its economics and solidifies its role as a valuable upgrade. Overall, the refined analysis of transmission options, further described in **Section 4.6 Transmission options for portfolio analysis,** provides a clearer picture of the timing and benefits of various projects, which will inform PGE's strategy for planning sufficient transmission capacity to access diverse resource zones and potentially lower cost markets.

Staff Recommendations Incorporated

The Update addresses several conditions from LC 80 Order 24-096. Broadly, the Update refined and expanded analysis of transmission and local resources as alternatives to large-scale transmission expansion. PGE has conducted a more comprehensive analysis of transmission constraints and potential solutions as supported by third party analysis. The company has expanded its evaluation of transmission options beyond BPA's system to include potential projects that would access more diverse climate zones, responding to stakeholder concerns about transmission development matching the urgency of PGE's needs. The update also reflects PGE's continued assessment of the Bethel-Round Butte 500 kV upgrade, which was identified by the OPUC as a project to study for increasing PGE's import capability.

4.1 Transmission and regulatory environment

PGE-owned and contracted-for generating resources to serve load are both directly connected to PGE's transmission system and remote to PGE's system. PGE's transmission portfolio – comprised of PGE-owned assets and held transmission rights – is designed to ensure reliable delivery of electricity from this broad array of generation resources to load. Variable energy resources that generate non-emitting electricity will need to be added to meet growing load and decarbonize towards the targets of HB 2021. Increasingly these resources are expected to be developed in new geographic areas, with their delivery to PGE's system requiring expanded transmission infrastructure and growing interconnectedness in the West.

4.1.1 Regulatory environment

As a vertically integrated investor-owned utility that is regulated by the Federal Energy Regulatory Commission (FERC), PGE is obligated by FERC to functionally separate its Transmission Function (PGET) from its Merchant function (PGEM). PGET is required to plan and operate PGE's transmission system in a non-discriminatory manner that provides open access to all transmission customers, including PGEM. This means PGET cannot unduly preference PGEM and, by extension, the retail customers that PGEM serves. PGET's transmission customers include

PGEM, Oregon-defined Electricity Service Supplier (ESS) customers, BPA, and transmission customers who utilize PGE's transmission system to transmit power across the region.

PGEM is responsible for purchasing transmission rights – on PGET's transmission facilities and other regional providers – to deliver power to PGE's service area to meet PGE's load obligations. PGEM holds extensive rights on PGET's transmission system, as well as the BPA transmission system, the largest transmission provider in the Pacific Northwest.

Consistent with Federal requirements, PGE must plan and build its transmission system to meet the needs of all PGET transmission customers, including PGEM, ESS customers, and all other transmission customers.[69] Transmission customers typically utilize PGE's transmission system to serve load contained within PGET's system footprint or to transfer power through PGET's system to other transmission systems.

Transmission customers who serve load located within PGE's Balancing Authority Area (BAA) generally use a transmission service called Network Integration Transmission Service (NITS). Transmission customers who move power through PGET's transmission system for delivery to a point on another transmission system typically use Point-to-Point (PTP) transmission service. For PGET to develop its transmission plans for most NITS customers, with the State of Oregon-defined Electric Service Supplier (ESS) customers being the exception, PGE uses the ten-year load-and-resource (L&R) forecasts supplied by NITS customers along with PTP transmission service commitments and requests. ESS customers are not currently obligated to designate generation resources to serve their loads because they are allowed to take a secondary form of NITS service under Oregon law.

PGET uses the NITS customers' L&R forecasts and the best available information, including transmission service requests, generation interconnection requests, and information from neighboring transmission providers' transmission planning and construction activities, to determine the need and timing for investments in the transmission system. The bulk of PGET's NITS customer-driven needs comes from PGEM, which supplies energy and capacity for PGE's retail customers. Oregon's HB 2021 is central to PGE's strategy and the resource decisions of PGET's transmission customers, including PGEM, resulting in the need to develop new transmission system investment and deployment plans. The 2025 L&R letter from PGEM to PGET documents the expectation that PGEM's future resource needs will change, given the need to meet growing load and comply with HB 2021. PGET works with its customers, including PGEM, to plan the PGET transmission system to maintain reliable service as its customers' resource mixes change over the next several years.

While PGE's transmission customers, except ESSs, are required to provide annual L&R forecasts looking ten years into the future, transmission development in the West requires lengthy planning, rights-of-way (ROW) acquisition, permitting, and construction timelines that often take years. As such, PGET cannot rely solely on the L&R forecasts to plan future transmission investments and must plan its transmission system on a longer time horizon.

[69] Such as the principles of FERC Order Nos. 890 and 1000 and requirements of PGE's FERC-approved open access transmission tariff (OATT).

4.1.2 PGE's transmission system

PGE's transmission system serves roughly half of Oregon's population and powers approximately two-thirds of Oregon's commercial and industrial activity. It is highly integrated with other transmission systems in the west due to the highly networked nature of the regional transmission system.

The PGE service area is a compact area located primarily in Oregon's Willamette Valley. PGE owns and operates its transmission system and BAA to deliver energy to retail customers while also providing transmission service to other wholesale transmission customers as required by FERC and in accordance with PGET's OATT. Most of PGE's existing, owned transmission assets are within the PGE service area. PGE also owns transmission assets in central and southern Oregon and Montana. PGE is obligated to plan, build, and operate the transmission system in a manner that reliably delivers power to serve customer load and the needs of PGET's OATT transmission customers.

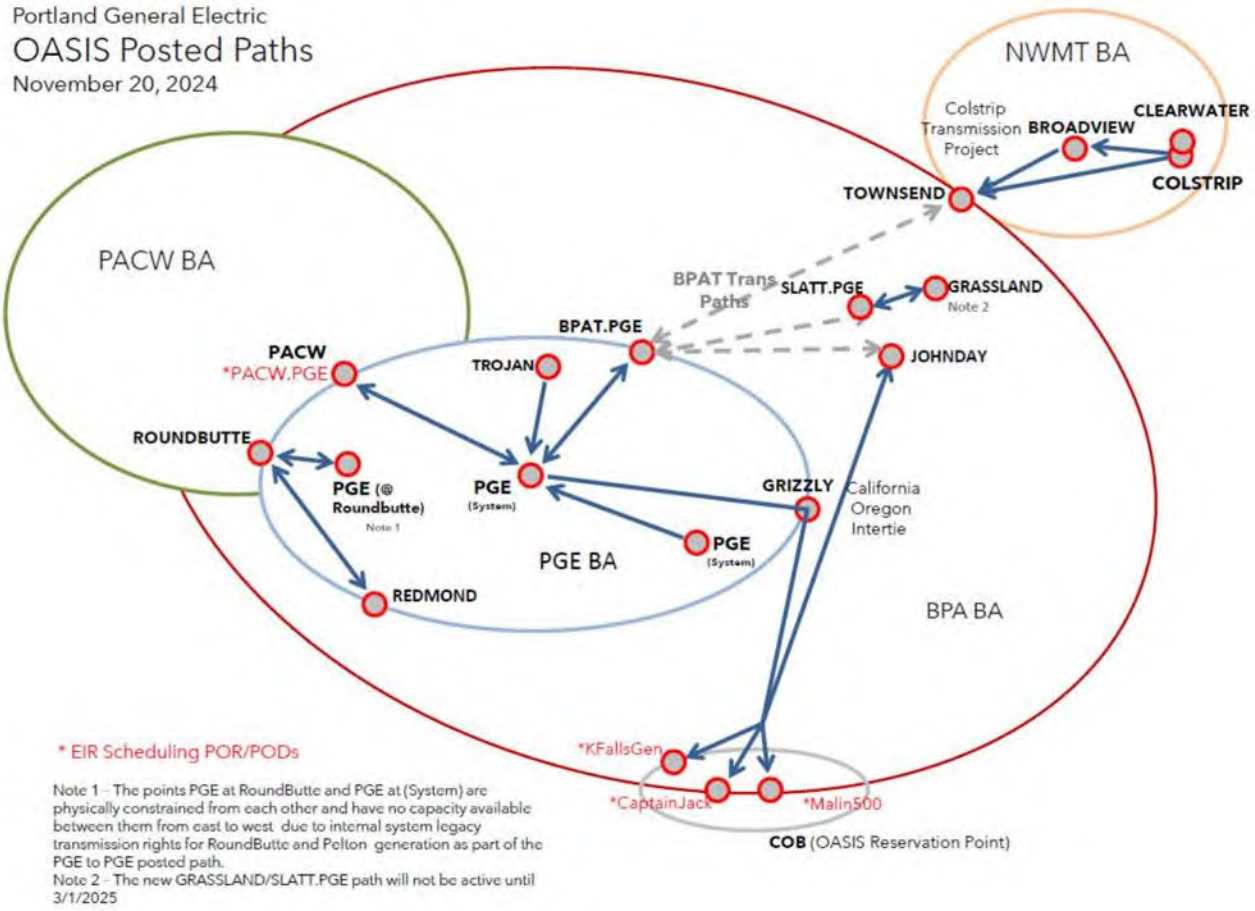
The PGE transmission system has 268 miles of 500 kV, 334 miles of 230 kV, and 559 miles of 115 kV lines, 454 circuit miles of 57 kV lines, and includes 176 substations and switching stations.[70]

4.1.3 Transmission system topology

PGE's transmission system (**Figure 29**) is highly interconnected with and exists almost entirely within the footprint of BPA. PGE is also interconnected to the western part of PacifiCorp's system, albeit with a much smaller transfer capability than PGE's interface with BPA. PGE's interface with PacifiCorp is primarily used to meet obligations within the Energy Imbalance Market (EIM). PGE is a co-owner of the Colstrip Transmission System, two 500 kV transmission circuits in Montana that runs between Colstrip and BPA's system in western Montana. Additionally, PGE owns one of the three 500 kV circuits in central Oregon that comprise the Northwest AC Intertie (NWACI), which is part of the California-Oregon Intertie, that connects Oregon to California. PGE jointly owns NWACI with BPA and PacifiCorp, and it is operated by BPA.

[70] An asset reclassification of PGE's 57 kV assets as transmission has been approved by the OPUC and is currently under review with FERC.

Figure 29. Oasis posted paths



4.1.3.1 BPA and Pacific Northwest transmission system

BPA is a federal power marketing administration (PMA) that operates approximately 75 percent of the transmission in the Pacific Northwest, consisting of more than 15,000 miles of high-voltage transmission lines. BPA operates transmission in Idaho, Oregon, Washington, western Montana and small parts of eastern Montana, California, Nevada, Utah and Wyoming.[71]

4.1.3.2 PGE and BPA

PGE's system is largely surrounded by BPA's transmission system. PGE has long relied on BPA transmission to deliver energy from throughout the west to serve PGE load. PGE currently holds over 4000 MW of long-term firm transmission under contract with BPA. The rights held on BPA's system deliver energy from discrete points, either on BPA's system or from the edge of BPA's system to PGE. These rights are known as point-to-point transmission rights and the points of receipt and delivery are set in perpetuity. This means that if a resource that would normally utilize

[71] BPA transmission system: https://www.bpa.gov/-/media/Aep/about/publications/maps/bpa-transmissionlines-and-facilities.pdf.

certain rights is unavailable, the unused transmission rights cannot be used to access different points on BPA's system. As discussed by BPA and stakeholders throughout BPA's recent Transmission Study and Expansion Processes (TSEP), BPA's system is effectively fully subscribed, and incremental transmission requests are unlikely to be granted until the early to mid-2030s, pending significant upgrades. Additionally, BPA has recently announced a pause to their TSEP process entirely while they attempt to develop reforms to their transmission service request process. As such, future transmission planning and procurement activity recommended throughout this chapter is a way to expand and diversify transmission options as the energy associated with serving load is decarbonized. It is important to recognize that the identification and development of transmission solutions are long-lead-time activities that often take longer than the Action Plan window time horizon of the IRP. Given this dynamic, it is necessary to engage in transmission planning and development on a forward-looking basis beyond the Action Plan window. See the description of the West-Wide Transmission Study Project (**Section 2.3.1 Western Transmission Expansion Coalition (WestTEC)**), a 10-year and 20-year transmission study addressing interregional and interstate transmission needs spanning the Western Interconnection.

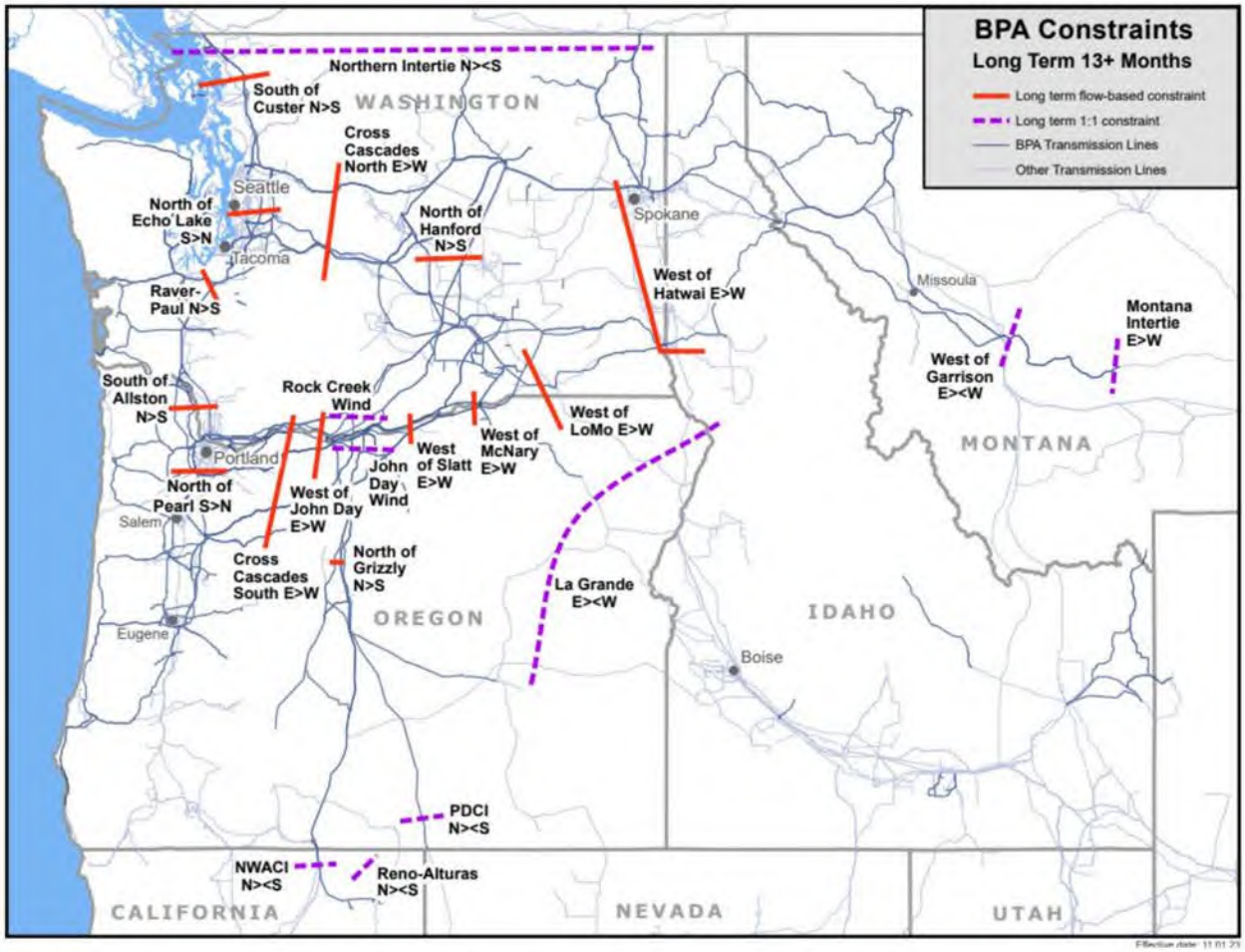
4.1.3.3 Paths and flowgates

To get to PGE's system, power generated or purchased from remote locations must travel through different paths and flowgates on the region's transmission system. A flowgate is a collection of transmission lines and facilities that collectively start in a geographically similar area and terminate in a different geographically similar area. These flowgates are typically operated by BPA and are shown in **Figure 30**. The flowgates that currently have the most significant impact on PGEM's transmission rights portfolio are North of Pearl, South of Allston, Raver Paul, West of John Day, and Cross Cascades South, all of which are constrained, with little or no ATC.

Flowgates are used by BPA as a way to monitor flow through areas of constraint on their system. Conceptually, when managed appropriately, the establishment of flowgates allows for a transmission provider to monitor system flows and take action to mitigate system constraints in the real-time operations horizon. Congestion at flowgates can be caused by different reasons including:

- Localized high loads at the receiving end of a flowgate in excess of flowgate capacity,
- Localized concentration of generation resources at the sending end of a flowgate trying in excess of flowgate capacity, and
- Flow-though, also known as loop flow, where far-flung regional load and generation dispatch scenarios create flows in excess of transmission capacity.

Figure 30. BPA Constraints[72]



The following summarizes the most significant flowgates and paths affecting energy delivery from remote resources to PGE's service area.

- The North of Pearl flowgate was instituted in August 2023 and has presented PGE with challenging operational scenarios since. The flowgate generally exists between the Wilsonville and Sherwood areas, SW of Portland. It is most constrained during periods of high renewable resource production in California and the desert southwest when it is also cool in the Pacific Northwest. Much less frequently, high Portland area loads can also contribute to high flows on North of Pearl. Further explanation of the North of Pearl flowgate will be described below.
- Some amount of energy from the majority of PGE's generating resources flows across the constrained South of Allston flowgate. This flowgate is most constrained during heavy summer and heavy winter loading periods. The South of Allston flowgate is a collection of several electrically parallel transmission lines that route from north to south just north of the

[72] Source: https://www.bpa.gov/-/media/Aep/transmission/atc-methodology/atc-long-term-constraints-11-1-23.pdf.

Portland metro area. Historically, the South of Allston flowgate was most constrained in the summer months.

- A large portion of the energy flowing from PGE's remote resources flows across the West of Cross Cascades South (WOCS) flowgate. Additionally, depending on the resource location, energy will flow across the West of John Day flowgate and the Raver-Paul flowgate. The WOCS flowgate is typically most constrained during heavy winter loading, while the West of John Day and Raver-Paul flowgates are typically most constrained during heavy spring and summer loading. PGE's Bethel-Round Butte 230 kV transmission line is part of the WOCS path.

Energy from PGE's resources in Montana first flow over the West of Garrison flowgate before reaching several other flowgates on the way to PGE's load in the Willamette Valley.

4.1.3.4 North of Pearl

The North of Pearl (NOPE) flowgate consists of a combination of BPA and PGE lines that run between BPA's Pearl substation in Wilsonville, OR to PGE's Sherwood substation in Sherwood, OR. The flowgate is comprised of BPA's Pearl-Keeler 500kV line, the Pearl BPA-Sherwood #1 & #2 230kV lines, and the McLoughlin-Pearl BPA-Sherwood 230kV line. The flowgate was instituted on August 11, 2023, a few days prior to a heatwave that blanketed much of the PNW. The NOPE flowgate was originally intended to be enabled in November 2023, prior to the winter operating season, but was expedited by BPA with the extreme heat that occurred in August 2023.

The NOPE flowgate was originally enabled for the purposes of monitoring south-to-north (S-N) flows through the Portland area. Previously, S-N flows were monitored as part of the South of Allston flowgate, but in a S-N flow pattern. BPA eventually shifted the focal point for monitoring S-N flows from the South of Allston flowgate to the more appropriate NOPE location. The South of Allston S-N flowgate was retired in early 2024.

During spring of 2024 and 2025, there have been several occasions where the North of Pearl flowgate reached S-N transmission flow levels near the upper limits of the flowgate limit high renewable resource imports from California and the desert southwest and low hydro generation output from British Columbia. Additionally, unscheduled energy flows have been observed coming into the Pacific Northwest and through PGE's service territory. These unscheduled flows, and the load and resource dispatch patterns several hundreds of miles away from PGE's system in either direction, have caused BPA to take real-time mitigation actions that included: sending congestion signals to the EIM marketplace that dispatched PGE Port Westward gas resources unexpectedly, halting short-term firm transmission sales, stopping all hourly redirects on BPA's system, and curtailing approximately 4000 MWs of transmission schedules across the region. If these scenarios had happened at higher local Portland area load levels, BPA curtailment of firm transmission schedules could have resulted in reliability concerns for PGE.

As PGE anticipates significant load growth into the future from the semiconductor and data center industrial sectors, much of the forecasted growth will locate in the Beaverton/Hillsboro area on the west side of PGE's service territory. Existing constraints north of the NOPE flowgate will limit industrial growth here. Additionally, it is expected that solar deployments will continue

in California and the desert southwest, further exacerbating the NOPE flowgate constraint. PGE and BPA are collaboratively planning how to address the NOPE constraint. Constraint mitigation will require a combination of new and upgraded transmission facilities as well as new operational scenarios that are currently being evaluated.

4.2 PGE transmission projects

Various FERC and NERC compliance and regulatory obligations require that PGE develop, engineer, procure, and construct PGET-owned transmission projects. Transmission projects can develop as a result of NERC reliability obligations, be driven by transmission or interconnection customer actions, result in response to state policy actions, load growth, and resource forecasts and requests by PGET's network transmission service customers.

Key transmission projects placed in service in 2024 include:

- A new 1.7 mile 230 kV transmission line between BPA's Keeler substation and PGE's Horizon substation, both located in Hillsboro, Oregon.
- The Evergreen Substation, a new bulk substation located in Hillsboro, Oregon that facilitates the interconnection of PGE's Constable Battery Energy Storage Facility, as well as the ability to serve new load in Washington County.

PGE revisits transmission plans and projects on a specific time cadence, with those in **Table 12** representing current plans. Future needs will continue to be evaluated over time. For the Near-Term and Long-Term Planning Horizon, PGE has identified transmission projects which will be needed to maintain compliance with the NERC TPL-001-5 standard. Each project has identified a completion date and any long lead time items that are required as a part of the work. Any construction phases which need to be scheduled are also identified and assessed to ensure that the reliability to the Bulk Electric System is not compromised during each phase of a project.

Table 12. Transmission Projects

Project Name	Anticipated In Service Date
Bethel-Round Butte 230kV Fixed Series Capacitor Project	2027 March
Bethel-Round Butte 500kV Project	2032 November
Blue Lake (Sundial) 230kV Battery Project	2025 June
Grassland 500kV Breaker Addition	2026 July
Harborton-Trojan #3 and #4 230kV	2033 May
Horizon-Keeler #1 & #2 230kV 4000A Upgrades	2029 April
Horizon-Keeler #1 230kV Reconductor Project	2026 May
Horizon-Keeler BPA #2 230 kV Project	2024 May
Jefferson Solar Project	2027 March
Madras Solar Project	2027 March
Memorial Substation Project	2025 July

Project Name	Anticipated In Service Date
Monitor Rebuild Project	2026 April
Pearl BPA-Sherwood 230 kV Project	2026 June
Reconductor Murrayhill-Sherwood 1&2	2027 May
Reconductor Murrayhill-St Marys #1, construct new Murrayhill-St Marys #2 section to create Sherwood-St Marys	2028 Q1
Reconfigure Murrayhill-Sherwood, Murrayhill-St Marys, Sherwood-St Marys	2028 Q1
Rivergate (Seaside) 230kV Battery Project	2025 June
Sherwood 115kV Project	2028 June
Shute and Sunset Facility Upgrades Project	2026 April
St Marys 115kV Breaker Replacement Project	2028 August
Sunset 115kV Bus Split Project	2027 April
Tonquin Substation Project	2026 December
Willamette Valley Resiliency Project (3 parts)	2035 May (latest part)
Hillsboro 500kV Expansion (Arden/Harrington)	2030 May

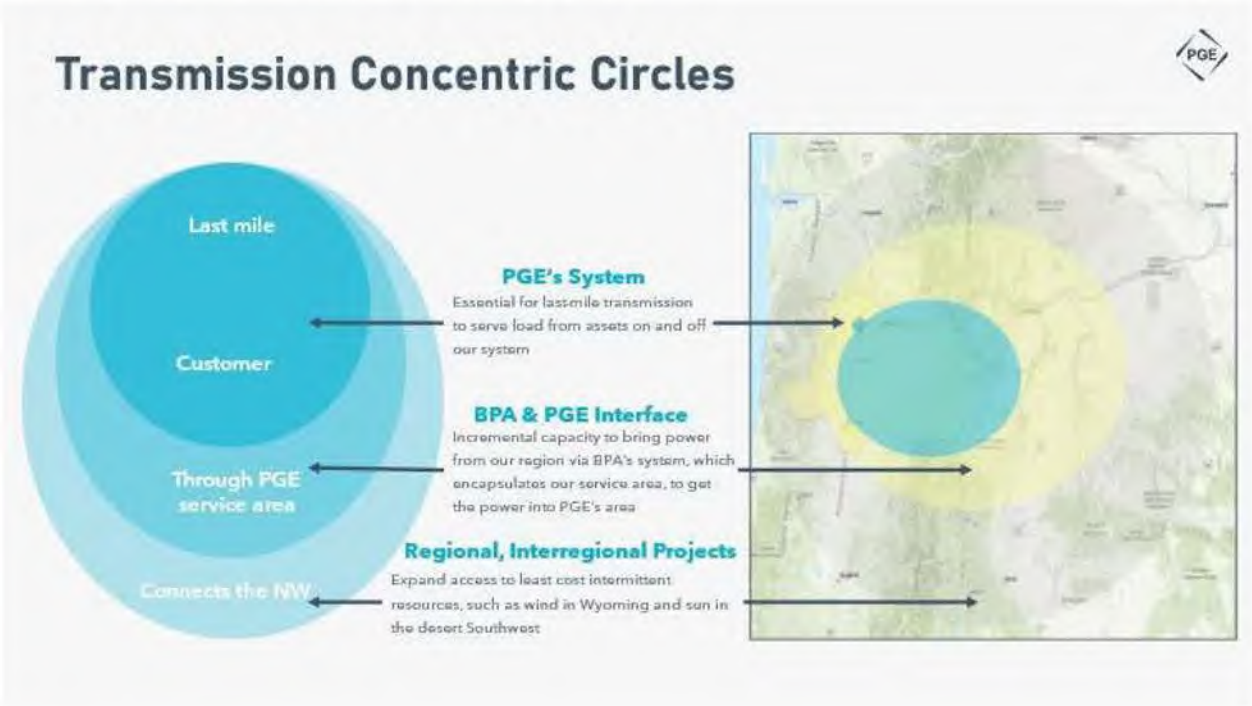
4.3 Transmission strategy/outlook

PGE will deploy a portfolio of strategies to meet future transmission needs and intends to explore expanding transmission access through the acquisition of rights on third-party systems, equity investment in regional projects as they are constructed, and PGE-developed projects, including upgrades of existing assets. PGE is also exploring Grid Enhancing Technologies (GETs), including actively putting in dynamic line ratings, with some of these projects utilizing advanced conductor and capacity enhancements. These different avenues of transmission expansion will allow PGE to optimize for the least cost and least risk plan to meet future needs and will continue to be discussed in the next full IRP.

4.3.1 Concentric circles of transmission

As PGE assesses strategies to meet load growth obligations and decarbonization goals and HB 2021 requirements, PGE must ensure transmission capacity is available from geographically diverse resources. Often, delivering energy to PGE's system requires multiple segments of transmission lines. Because PGE's network load is centralized in a compact service area, instead of dispersed out in multiple areas of load, PGE utilizes a concentric circle model to contemplate available transmission options, displayed below in **Figure 31**.

Figure 31. PGE Transmission Concentric Circles



4.3.1.1 PGE's system

The inner most circle in the model, 'Circle One', is predominantly used to move power through PGE's system for the purposes of safely and reliably serving PGE network load. It is important to remember that PGE network load includes PGE retail customer loads and also the loads of ESS customers and other transmission customers. PGE performs a series of annual transmission planning and reliability assessments. As Circle One on the system is planned, not only must PGE network load be accounted for, but also the potential for energy to flow through PGE's system enroute to other utilities in the western interconnection. These routine transmission planning efforts identify the projects necessary to reliably and safely serve PGE load, accounting for transmission service requested through PGE's service territory, and accounting for the impact regional resource dispatch patterns can have on PGE's transmission system.

4.3.1.2 Connecting PNW to PGE's transmission system

'Circle Two' in the model connects PGE's service territory to BPA's system and the rest of the PNW transmission system. Because PGE's service area is so concentrated in the northern Willamette Valley and new non-emitting generation resources will be generally located in remote geographic locations, PGE must determine how to best enable resources to reach the system. An example of Circle Two transmission would be transmission that enables energy to cross the Cascades enroute to PGE or adds additional capacity to the South of Allston flow gate flowing from north of the Portland Metro area.

4.3.1.3 Connecting the PNW to other regions

'Circle Three', the outer most circle, connects the PNW to other resource rich regions like the Dakotas and eastern interconnection, Rocky Mountains, and the Desert Southwest. Projects that connect multiple regions are often proposed and developed by large independent transmission companies who can more easily absorb the additional risk these large ambitious projects carry.

4.3.1.4 Grid Enhancing Technologies (GETs)

GETs are solutions that aid in the optimization of existing grid infrastructure. These technologies help PGE more effectively manage power flow for the aim of increasing capacity, efficiency and reliability on the system and to reduce the need for more costly grid expansion. The categories below detail GETs in use and planned for PGE's service area.

Dynamic Line Ratings (DLRs)

PGE is integrating DLRs beginning 2025 through partnership with the Electric Power Research Institute (EPRI) and BPA. DLRs are a method for determining available transfer capability of transmission lines utilizing real-time data to account for weather. DLRs can increase real-time capacities under favorable weather conditions (lower ambient temperature, higher wind speeds, and cloud shadowing) and derate capacities when weather is unfavorable. This additional operational flexibility is intended to help with reducing overloads due to unplanned outages or allow for better certainty of planned outages and system impacts. An impact analysis will be studied in 2025 and refined as the DLR system goes in-service and real time performance data becomes available over the second half of 2025.

Conductor Coating Technologies

PGE is integrating heat-dissipating overhead conductor coating technologies that reduce power loss and increase power carrying capacity. PGE's first use of the coating is for the 1.5 mile Horizon-Keeler #1 230 kV reconductor project is expected begin construction in 2026.

Topology Optimization

PGE utilizes switching of circuit breakers on the existing system to optimize power flow. PGE operations teams have long used this tool to more effectively change system flows as an alternative to costly options such as generation redispatch. PGE is upgrading a 230kV circuit breaker at the McLoughlin substation in 2025 to support this topology optimization practice.

Advanced Conductors

PGE is working with EPRI and other utilities on the Grid Enhancing Technologies for a Smart Energy Transition (GET SET) initiative to design and construct high temperature Aluminum Conductor Steel Supported (ACCS) lines in the territory. PGE has utilized ACCS conductors since 2006 to help ensure efficient power transmission and mechanical reliability across long-distance transmission lines and these new high temperature low sag conductors are already integrated in PGE's transmission planning studies.

4.3.2 Existing PGE projects/local transmission plan

Refers to the inner circle in ***Figure 31.***

To address the needs identified during PGE's transmission planning assessments, a local transmission plan is developed that identifies the portfolio of projects to meet the needs of PGE's customers and to maintain and operate a safe, resilient, and reliable system. Historically, PGE has focused on planning within the inner circle for reliable and load service-driven transmission given PGE's unique geographic footprint within BPA's system. This was primarily because BPA traditionally had ample ATC on their transmission system that PGE has been able to leverage to transfer new remote generation resources to PGE's system. With the recognition that ATC inventories on BPA's system have been fully allocated, and that changes in resource dispatch patterns have created a paradigm shift in regional flow patterns on the west-wide transmission system, PGE's transmission planning and strategy have necessarily evolved from an approach based primarily on reliability and load service to a more proactive approach that aligns with future load service needs (described in **Chapter 3 System needs**) as PGE decarbonizes. It is important to recognize the significant transmission planning and project development efforts already underway that are necessary for reliable load service and proper cost allocation within PGE's load service area. PGE's local transmission plan has identified more than 20 projects, discussed in **Section 4.2 PGE transmission projects**.

4.3.3 BPA projects important to PGE

Refers to all circles in ***Figure 31.***

PGE's and BPA's transmission systems are highly interconnected, both in PGE's service area and around Oregon and the PNW. Because of the highly networked nature of PGE's transmission systems, PGE has been collaboratively working with BPA to ensure BPA has sufficient system reinforcements planned that, in concert with PGE's planned transmission projects, will enable PGE to reliably serve load. As a result of this collaborative system planning, PGE and BPA have identified a suite of projects, both joint PGE-BPA projects and BPA-only projects as shown in **Table 13**, necessary for the safe and reliable operation of the region's transmissions system. Several joint projects are inflight that will help address the NOPE flowgate constraint. In addition to joint projects, BPA has identified several projects that only involve work to their infrastructure that will have significant impact for PGE and its customers. Several of them are currently in-flight or in the scoping phase.

Table 13. PGE-BPA and BPA-only Transmission Projects

PGE-BPA Transmission Projects	BPA-only Transmission Projects
Pearl-Sherwood-McLoughlin Bifurcation & Reconductor	Big Eddy-Chemawa Upgrade (Evolving Grid 1.0)
N. of Sherwood Reconductor	Keeler Transformer Bank Addition (Evolving Grid 1.0)
Horizon-Keeler #1 reconductor	Pearl-Keeler 500kV #2 (Evolving Grid 2.0)
Horizon-Keeler 4000A upgrades	North of Marion Upgrades (Evolving Grid 2.0)
Ross-Rivergate (BPA Evolving Grid 1.0 Project)	Ostrander-Pearl #1 Line Upgrade (Evolving Grid 2.0)
Harborton 230 kV Rearrangement	
Willamette Valley Resiliency Project	

Figure 32. PGE-BPA transmission projects

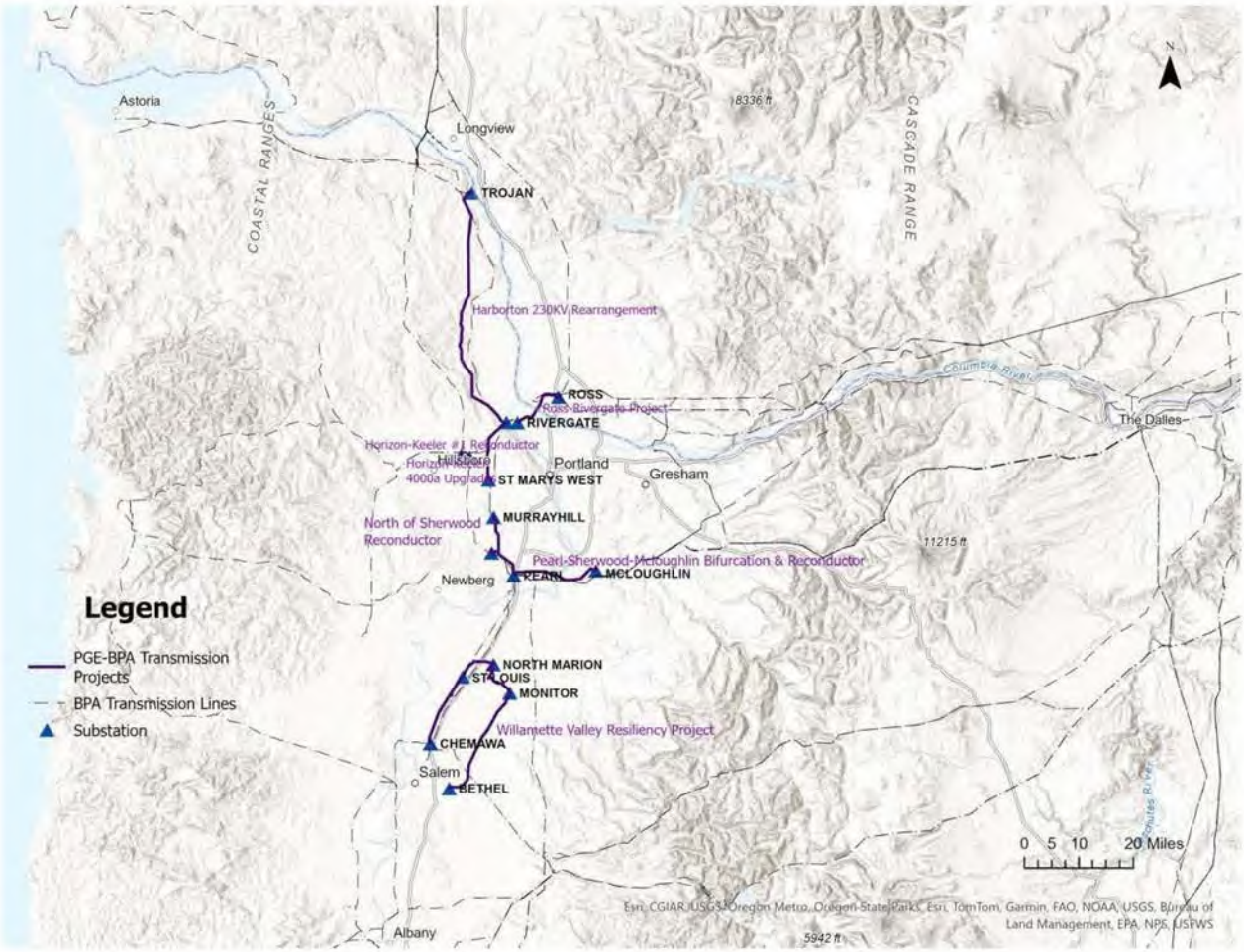
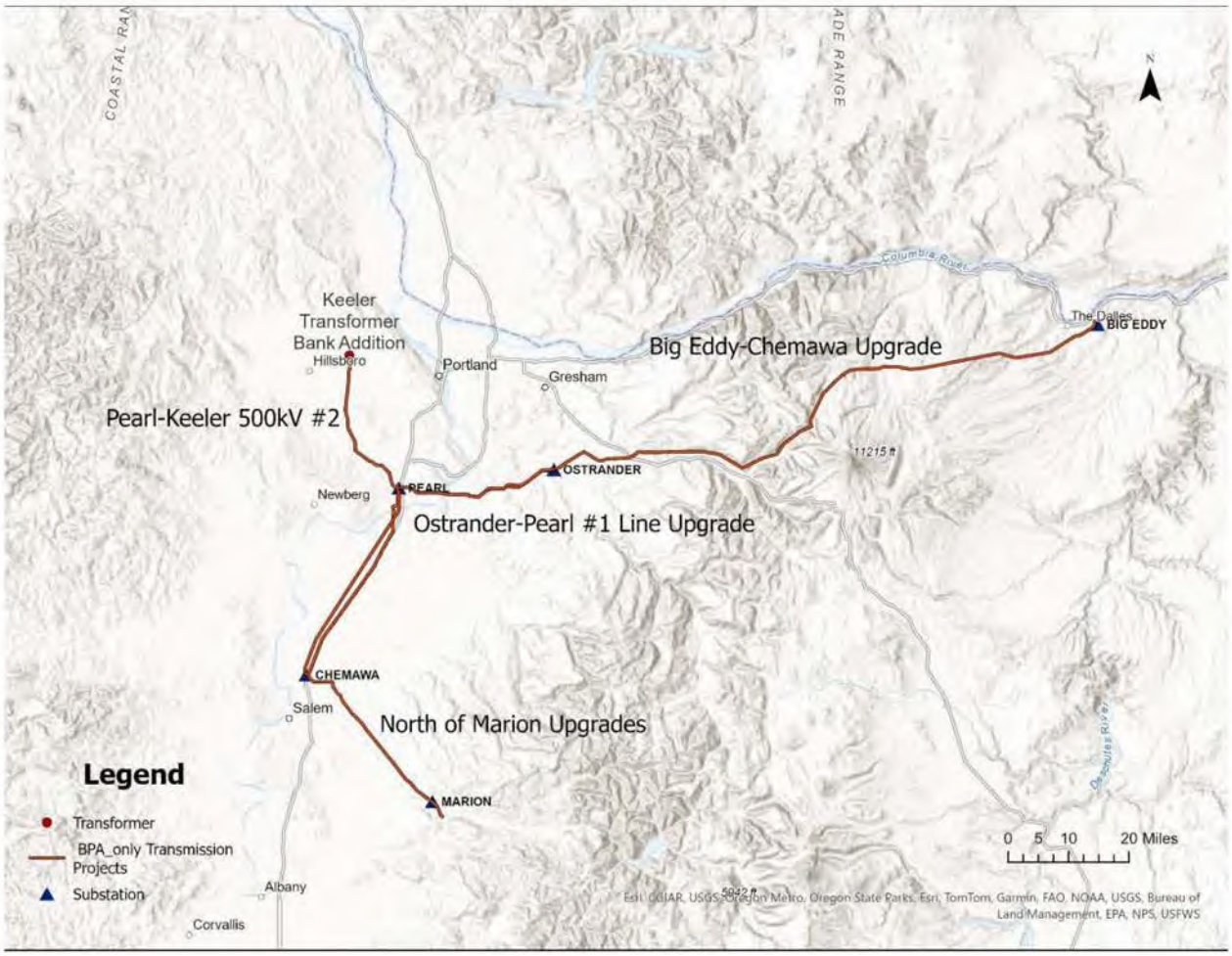


Figure 33. BPA-only transmission projects



4.4 Assessment of available BPA point-to-point transmission

Limitations on the region's transmission system constrain PGE's ability to access Pacific Northwest (PNW) renewable resources. For the 2023 CEP/IRP, PGE conducted a study of transmission service requests directed toward PGE in BPA's Transmission Study Request (TSR) Study and Expansion Process (TSEP) reports in order to estimate the quantity of transmission currently available. As part of the transmission-related assumptions and modeling in the 2023 CEP/IRP, PGE included these estimates of available capacity on BPA's transmission system as a resource build constraint in portfolio analysis. The total ATC available in the 2023 CEP/IRP was 1818 MW.[73]

PGE has refreshed these estimates for the Update with the most up-to-date data available. The updated values, shown in **Table 14**, are included as constraints on resource additions in portfolio analysis.[74] The total ATC has increased by 688 MW compared to the 2023 CEP/IRP to

[73] See Appendix H.7 of the filed 2023 CEP/IRP.
[74] The updated numbers and methodology were described by PGE in the October 2024 Roundtable Meeting. Available here:

2506 MW. Total ATC determines the quantity of resources that can be added to PGE's portfolio without incurring the costs associated with transmission upgrades or expansion (as described in **Section 4.6 Transmission options for portfolio analysis**).

Regional transmission constraints in the 2023 CEP/IRP required that each MW of new renewable resource had 1 MW of associated transmission capacity. In the Update, this assumption has been updated, with each MW of transmission capacity now allowing access to 1.33 MW of renewable resources (requiring that 75 percent of new resources have associated transmission rights).[75] This increases the quantity of accessible resources from 2506 MW to 3341 MW. Excluding offshore wind, which has additional constraints that push earliest COD in portfolio analysis out to 2036, this results in access to 2451 MW of off-system renewables prior to the first available transmission upgrade option in 2032. Transmission availability is identified by transmission zones, with the transmission zone associated with each proxy resource identified in **Table 15**.

Table 14. Transmission ATC by resource zone

Transmission Zone	Long-Term Firm	Conditional Firm	Total ATC
Christmas Valley	201	466	667
Gorge	179	418	667
McMinnville	45	105	150
Montana	96	224	320
Offshore	201	467	668
SE Washington	31	73	104
Total	753	1753	2506

https://assets.ctfassets.net/416ywc1laqmd/6Gv0U2lLocu2YCSnHv4JRP/43c13f8b70898a4476a4655f5f783fd4/IRP_Roundtable_October_24-6.pdf#page=23

[75] This modeling change was discussed in PGE's January 2025 Roundtable. Link: https://assets.ctfassets.net/416ywc1laqmd/7rqJJm9XGJaw6HPuh9Oz4L/7e071838b5f9cdfd7a9d9185b1fe0b53/CEP_IRP_Roundtable_January_25-1-74-.pdf#page=8

Table 15. Transmission zones of proxy resources

Transmission Zone	Proxy Resources
Christmas Valley	Christmas Valley Solar Christmas Valley Hybrids
Gorge	Gorge Wind Wasco Solar
McMinnville	McMinnville Solar McMinnville Hybrids
Montana	Montana Wind
Offshore	Offshore Wind
SE Washington	Southeast Washington Wind

4.5 Third-party assessment of PGE regional transmission options

In response to Staff comments on the transmission action item and modeling from LC 80 Order 24-096, PGE contracted with two third-party consultants to more thoroughly evaluate viable transmission options and their modeled benefits.

First, PGE contracted with Energy Strategies to assess transmission options identified by PGE, their general viability and any alternative, related CODs, and firm MW access assumptions.[76] Three key categories of changes resulted from Energy Strategies' analysis, which were incorporated as seven transmission options into PGE's modeling as discussed in **Section 4.6 Transmission options for portfolio analysis**:

1. Two alternative projects were identified to replace PGE's options of TransWest Express for accessing Wyoming Wind Proxy Resources and Western Bounty for access to Nevada Solar Proxy Resources. Energy Strategies proposed these alternatives due to policy, price, and timeline risks with WesternBounty and TransWest Express.
2. CODs were adjusted outward into the future based on Energy Strategies' understanding of project statuses and best estimates of completion timelines.
3. MW access assumptions were adjusted downward to account for Energy Strategies' assessment of ATC and rights on the identified transmission paths.

Second, PGE contracted with Energy GPS to conduct a market liquidity analysis for energy markets adjacent to the Pacific Northwest.[77] This analysis developed an understanding of the added benefit that a given transmission project may provide through its connection to a broader but nearby market. To estimate the additional market access benefits of a transmission project, Energy GPS analyzed correlations in PGE's hours of greatest load with high load hours in CAISO, Desert Southwest (DSW), Midcontinent ISO (MISO) North, and Southwest Power Pool (SPP) North

[76] PGE's January 2025 Roundtable - Transmission Options. See also **Appendix J Transmission options study**.
[77] PGE's November 2024 Roundtable - Transmission - Step 3 - Market Access.

markets. The analysis resulted in two key conclusions, which PGE incorporated into each modeled transmission option's market access benefits:

1. It is reasonable to assume transmission to SPP North or MISO North can provide access to energy and capacity during critical hours for both summer and winter.
2. It is reasonable to assume transmission to DSW or CAISO markets can provide access to energy and capacity during critical hours during winter.

4.6 Transmission options for portfolio analysis

The transmission necessary to reach resource rich geographical locations can often rely on multiple segments of transmission infrastructure to reach from generation site to where demand is located. PGE continues to analyze and explore all publicly known transmission project opportunities in the west that could be useful in serving PGE loads but generally do not directly connect to PGE. PGE identified a list of potential transmission projects within the BPA-PGE interface (Concentric Circle 2, as described in **Section 4.3.1 Concentric circles of transmission**) and greater region (Concentric Circle 3). These projects would provide access to proxy BPA resources such as Gorge Wind and Christmas Valley Solar, and proxy interregional resources such as North Dakota Wind and Nevada Solar. The resulting list provides known possibilities that may allow PGE to expand access to off-system renewable resources and markets. PGE continues to conduct analysis of these projects and will update this assessment in the 2026 CEP/IRP.

The remainder of this section describes project specific details of options modeled in the 2023 CEP/IRP Update based on Energy Strategies' analysis and the assumptions used in modeling transmission options.

Figure 34 illustrates the transmission options recommended for study by Energy Strategies.

Figure 34. Overview of PGE Transmission Options

4.6.1 Bethel-Round Butte upgrade

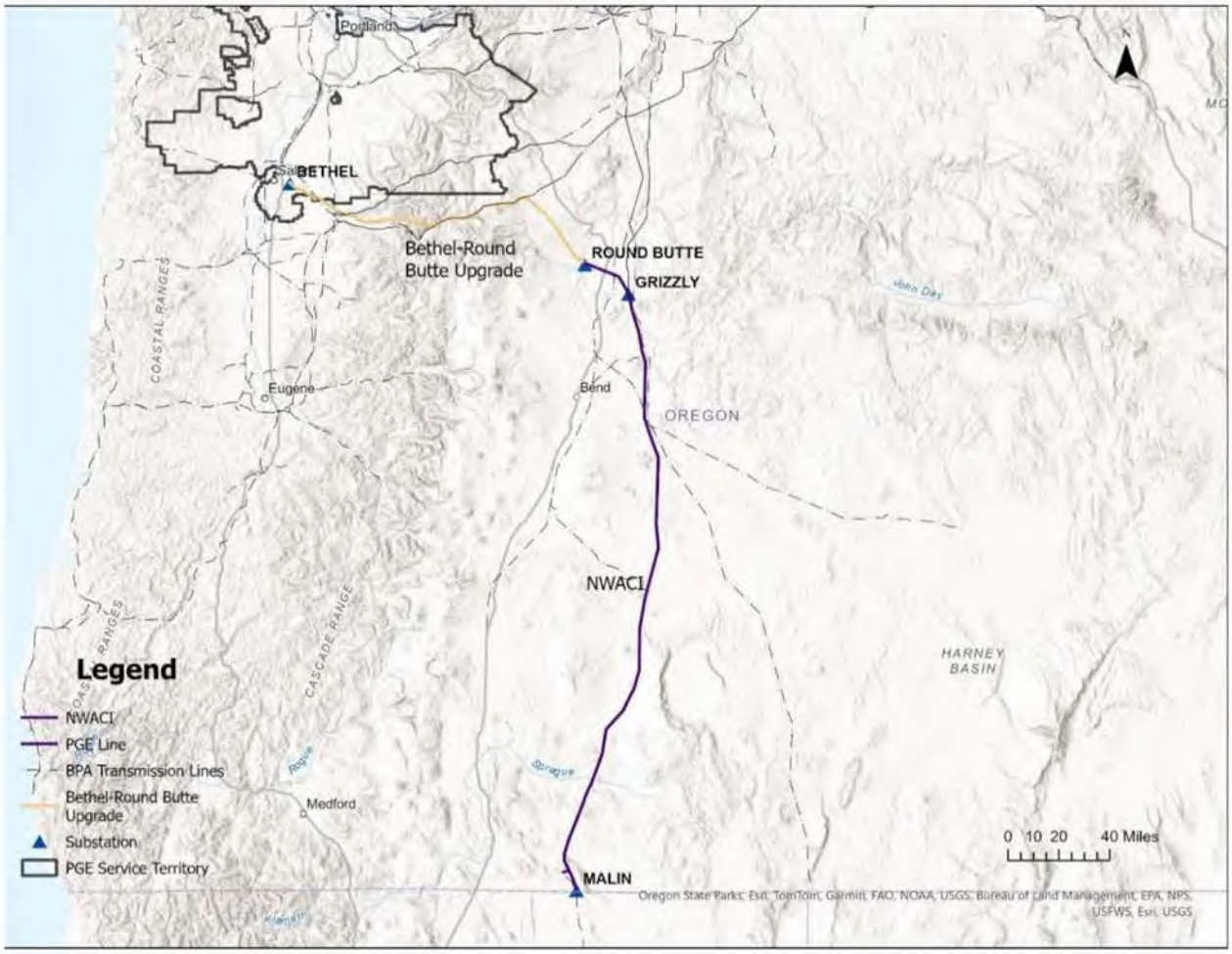
Bethel-Round Butte transmission project is a 98-mile 230 kV line upgrade running between PGE's Bethel and Round-Butte substations at the south-east edge of PGE's service territory. The project plans to rebuild the existing transmission line from 230 kV to 500 kV and build a second 500 kV line, enabling up to 3000 MW of additional resources from the BPA-PGE interface, or Concentric Circle 2 (**Section 4.3.1 Concentric circles of transmission**), to reach PGE's service territory. Resources within the BPA-PGE interface include: Wind Gorge, Wind SE WA, Solar CV, Solar MCMN, Solar Wasco, CV hybrids, and MCMN hybrids, and are resources that are assumed accessible by way of one wheel across BPA transmission infrastructure. Additionally, the project would increase access through the California Oregon Border (COB) to the CAISO market of 600 MW in winter.[78] The estimated commercial operation date (COD) for the upgraded line is 2032.

[78] PGE's November Roundtable - Transmission - Step 3 - Market Access.

The 2023 CEP/IRP characterized the Bethel-Round Butte transmission option as a valuable upgrade to the PGE system, necessary to integrate the scale of non-emitting resources required to offset fossil fuels.

In partnership with The Confederated Tribes of Warm Springs (CTWS), an application was submitted to the USDOE for a Grid Resilience and Innovation Partnerships (GRIP) Program grant for the Bethel-Round Butte upgrade. The GRIP application was successful, and a $250 million award was made to PGE's partners, the CTWS. The CTWS and PGE are currently in the process of developing the project.

Figure 35. Bethel-Round Butte Upgrade

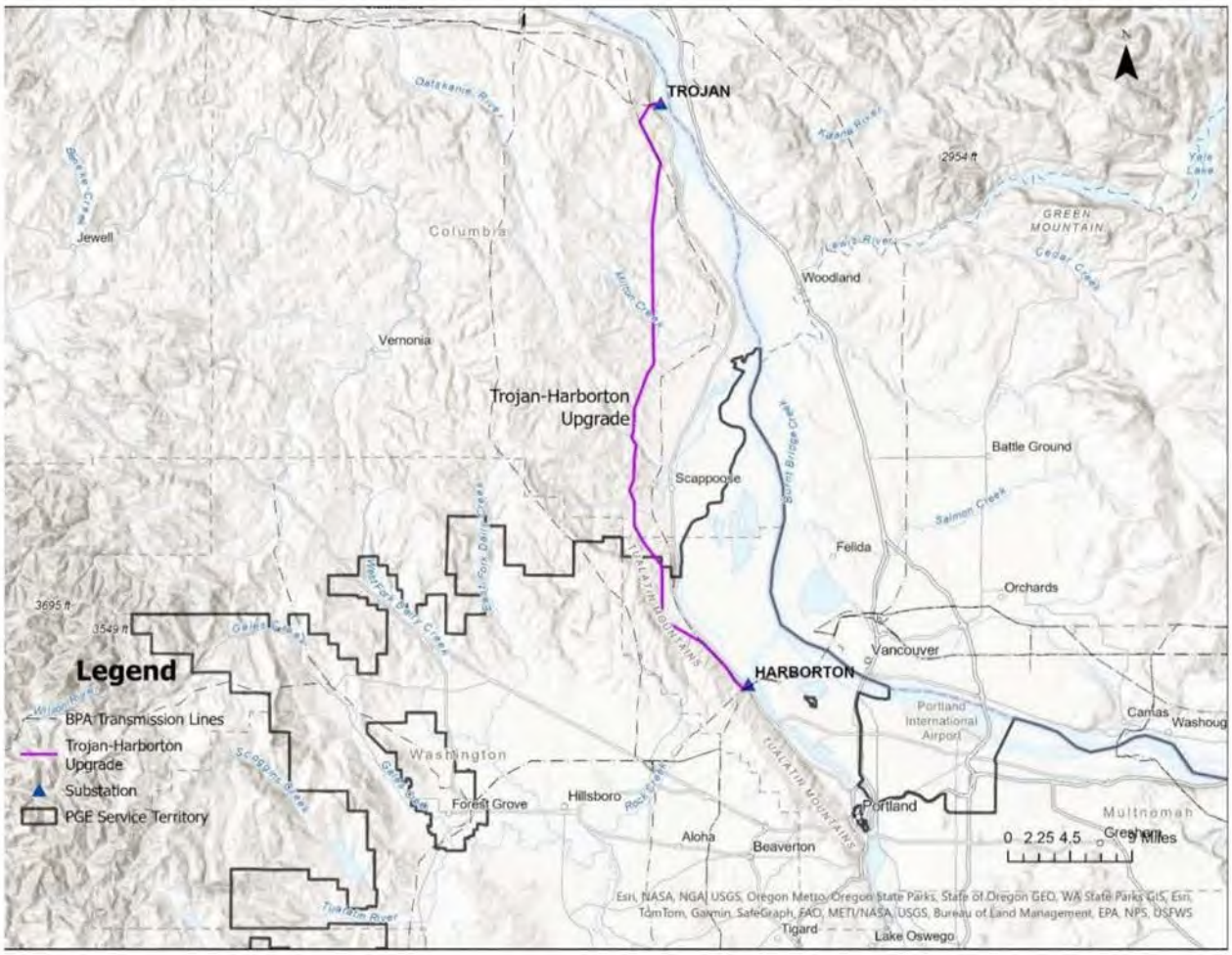


4.6.2 Harborton-Trojan upgrade

Harborton-Trojan Upgrade is a 34-mile 230 kV transmission option between these two PGE substations at the north-west edge of PGE's service territory. The project would run parallel to two existing PGE transmission lines, in service since the 1970s. PGE currently owns the right-of-way (ROW) necessary to complete this upgrade. The project is estimated to enable up to 800 MW from resources within the BPA-PGE interface to reach PGE customers, subject to cooperative

study and agreement with other South of Allston path owners, BPA and PacifiCorp. The anticipated COD of the project is 2035. It is assumed that the Harborton-Trojan option will provide no additional market-access benefits.[79]

Figure 36. Harborton-Trojan Upgrade



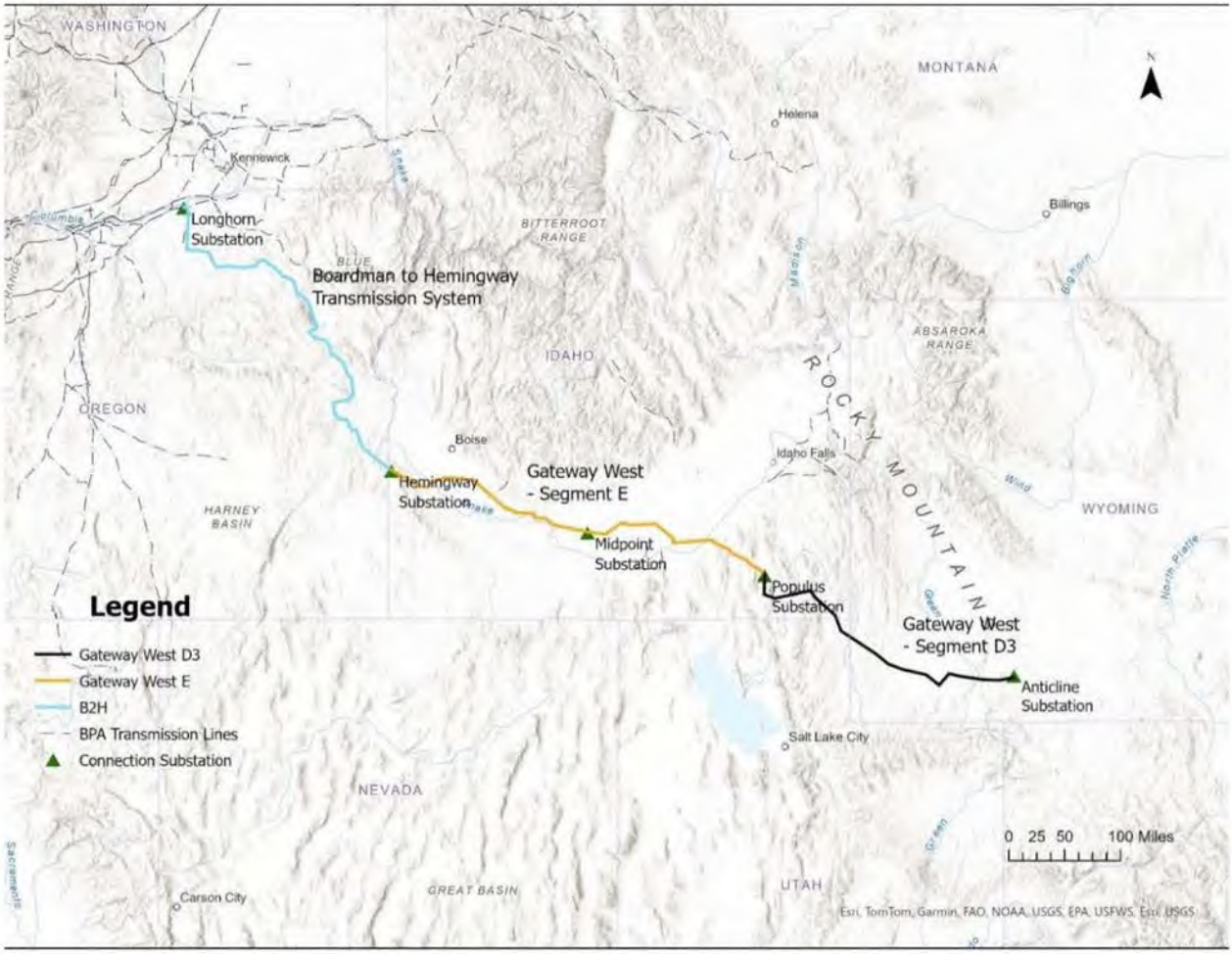
4.6.3 Gateway + B2H + Longhorn (Gateway)

The Gateway transmission option is modeled as the preferred path to access Wyoming Wind proxy resources. The Gateway option begins in western Wyoming, traversing 200 miles from Anticline to Populus substation along the Gateway West D-3 leg. The second segment covers 500 miles on Gateway West E segment where it terminates in Hemingway and then traverses 270 miles along the Boardman to Hemingway (B2H) leg. Finally, Longhorn to PGE is identified as a viable wheel to bring the energy to PGE service territory. The Gateway transmission option is estimated to provide up to 400 MW of capacity for Wyoming Wind by 2035. The 2035 COD reflects the expected timeline for new BPA Transmission Service Requests (TSRs) on the Longhorn to PGE leg. Additionally, Gateway is assumed to provide an additional 400 MW of

[79] PGE's November Roundtable - Transmission - Step 3 - Market Access.

market access during winter.[80] Securing firm transmission access for the Gateway option in the 2030's is uncertain due to competition with Pacific Power and Idaho Power Company and the required timely granting of transmission service requests.

Figure 37. Gateway Transmission Option



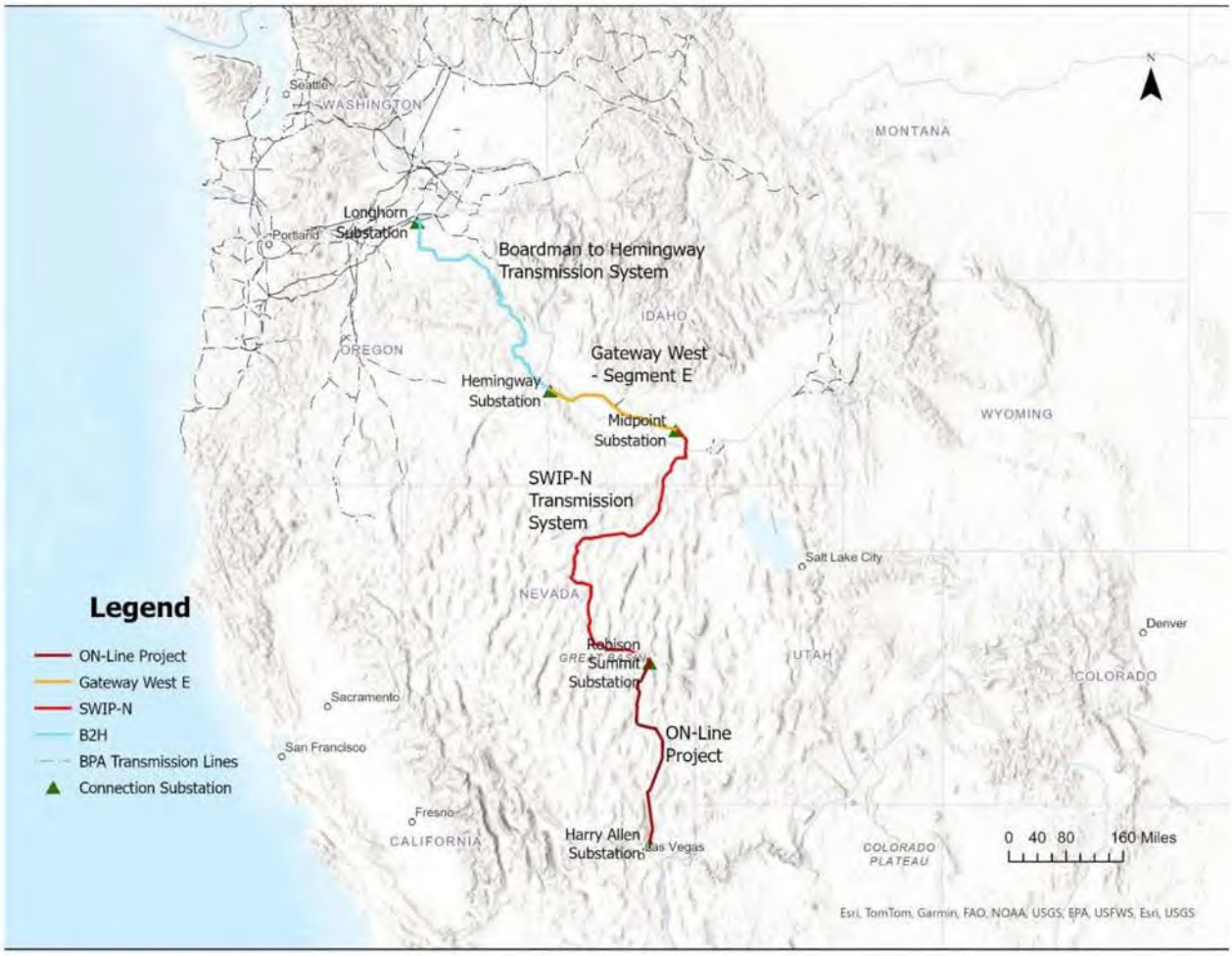
4.6.4 NVE + SWIP-N + Gateway + B2H + Longhorn (SWIP-N)

The SWIP-N transmission option includes approximately 673 miles of AC segments along the Southwest Intertie Project – North, Gateway West 8, and Boardman to Hemingway transmission projects. The option is composed of five segments, two of which are modeled as wheels. The first segment is represented as one wheel that captures PGE's need to move energy across the existing or committed NVE projects (Desert Link, ON-Line, Greenlink West, Greenlink North). Next, the option traverses the 275-mile Southwest Intertie Project – North project, then passes 128 miles along Gateway West 8 leg. The SWIP-N option utilizes the Boardman to Hemingway segment and a Longhorn to PGE wheel to bring energy to the PGE service territory. SWIP-N is estimated to provide capacity up to 400 MW of Nevada Solar by 2035 and an additional 400 MW

[80] PGE's November Roundtable - Transmission - Step 3 - Market Access.

of market access in winter.[81] The 2035 COD reflects the expected timeline for new BPA TSRs on Longhorn to PGE leg.

Figure 38. SWIP-N Transmission Option



4.6.5 North Plains Connector

The North Plains Connector (NPC) option includes a 412-mile 500kV HVDC incremental line segment and two additional wheels to reach PGE.[82] PGE has signed a non-binding memorandum of understanding with the developers of this line for a 20 percent stake (600 MW) in the 3000 MW line. Following PGE's MOU, on August 6, 2024, the US Department of Energy (USDOE) selected the NPC, in partnership with the State of Montana, for a $700 million GRIP grant. Pending the outcome of development and execution of definitive agreements, this significant GRIP grant is modeled to buy down the development costs for participation in the NPC project. Additionally, this grant apportioned $70 million for the upgrade of the Colstrip Transmission System (CTS).

[81] PGE's November Roundtable - Transmission - Step 3 - Market Access
[82] The tariff charges incurred to transit both CTS and the Montana Intertie (Townsend-Garrison) are assumed equivalent to the rate of a BPA PTP+SCD wheel.

The NPC would allow PGE to utilize 270 MW of existing firm transmission to replace generation from Colstrip Units 3 & 4 with energy from some of the highest capacity factor renewable resources estimated as part of the 2023 CEP/IRP Update (Table 20). Further, the NPC connects to the Southwest Power Pool (SPP), and the Mid-Continent Independent System Operator (MISO) Zone 1 Market, where historical data suggests a surplus of supply during approximately 80 percent of PGE's highest demand hours.[83] As such, the NPC is a valuable transmission option for addressing PGE's winter reliability challenges as discussed in **Section 6.2.3 Preferred Portfolio resource adequacy testing**.

The NPC option is modeled to provide capacity up to 600 MW of North Dakota Wind proxy resource by 2038. This COD reflects expected timing to receive requested BPA and Northwestern (NWMT) TSRs. Six hundred MW represents what is assumed commercially available and aligns with PGE's existing transmission rights of 270 MW on CTS plus approximately 300 MW of firm and short-term rights on Northwestern path associated to PGE's Clearwater project. In addition, PGE has submitted TSRs for an additional 720 MW across BPA's and NWMT's system. Access to the benefits associated with the assumed 600 MW of potential capacity on this line requires that at least some of the additional submitted TSRs be approved. If submitted TSRs do not come to fruition, PGE's access to the capacity of the line would be only the current 270 MW of PGE's rights along the CTS. The 270 MW of firm transmission access across the CTS are available with the exit of Colstrip Units 3 & 4, assumed after 2029.[84] However, modeled access to these resources is not captured from 2030 to 2037. The NPC is modeled to provide access to an additional 600 MW of both summer and winter market access through its connection to the Eastern Interconnection, the SPP and MISO Zone 1.

[83] PGE's November Roundtable - Transmission - Step 3 - Market Access
[84] PGE's November Roundtable - Transmission - Step 3 - Market Access

Figure 39. North Plains Connector

4.6.6 NVE + Greenlink 3 + Cpt. Jack to Grizzly + BRB upgrade (Greenlink)

The Greenlink transmission option includes 300 miles of additional AC circuits, and one wheel along Nevada Energy (NVE) infrastructure. The Greenlink option is modeled with four line segments from generation site to PGE's service territory. The first segment is comprised of one wheel that captures PGE's need to move energy across the existing or committed NVE projects (Desert Link, ON-Line, Greenlink West, Greenlink North). Second, the path incurs 300 miles of incremental costs from Ft. Churchill substation in eastern Nevada to the Captain Jack substation near Path 66 at COB. Energy is then moved from Captain Jack to the Grizzly Substation, a point along the Northwest AC Intertie (NWACI) and adjacent to PGE's transmission footprint, using existing PGE rights. Finally, the path assumes the Bethel-Round Butte Upgrade is in place to bring the energy to PGE's service territory. The Greenlink option is estimated to provide PGE up to 627 MW of proxy solar resources from Nevada with an expected availability date of 2035. The COD reflects estimated timing of the Greenlink 3 segment from Fort Churchill to Captain Jack. Further, an additional 627 MW of market access in the winter is assumed.[85]

[85] PGE's November Roundtable - Transmission - Step 3 - Market Access.

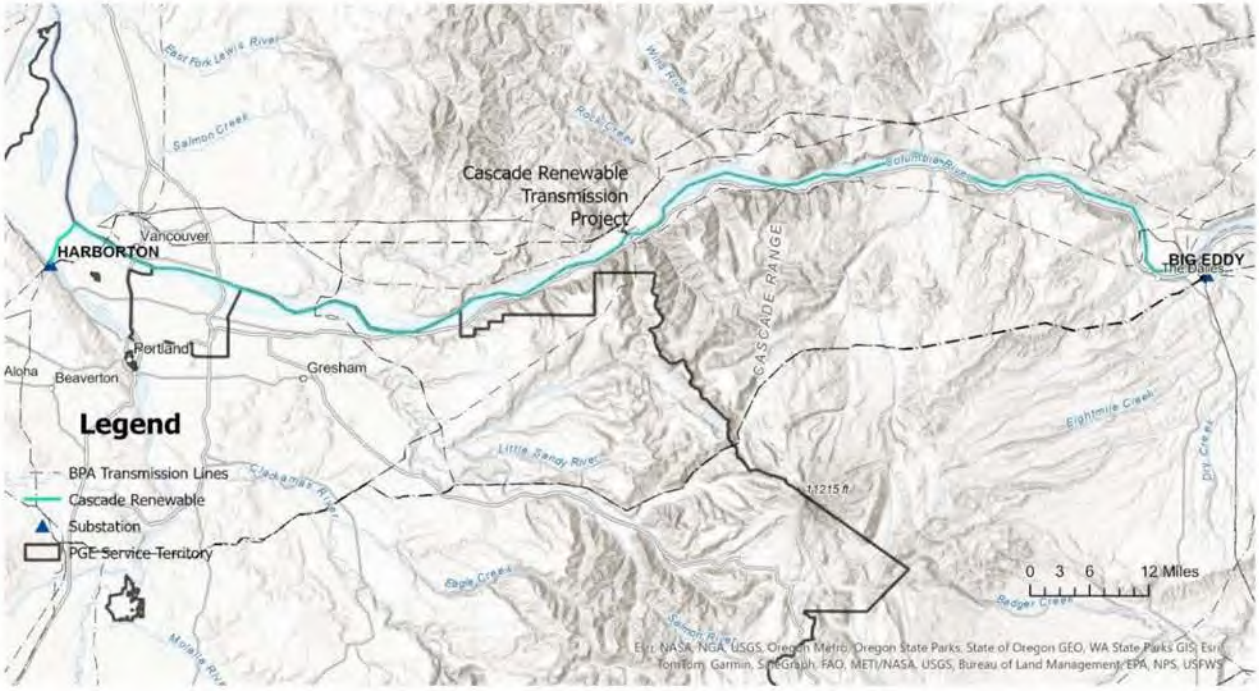
Figure 40. Greenlink Transmission Option

4.6.7 Cascade Renewable Transmission project

The Cascade Renewable Transmission Project (CRT) is an underwater HVDC transmission option of 100 miles that would route from BPA's Big Eddy substation near The Dalles, OR to PGE's Harborton Substation in NW Portland. The project is modeled as one incremental line of additional transmission. The project would allow up to 1100 MW of new east-west transmission capacity for PGE to access off-system proxy resources in the Pacific Northwest, such as Christmas Valley Solar and Southeast Washington Wind. The project will require additional BPA and PGE transmission expansion for PGE to access these benefits and is estimated available by 2038. Additionally, The CRT is assumed to provide no additional market access benefits.[86] PGE is not currently participating in CRT.

[86] PGE's November Roundtable - Transmission - Step 3 - Market Access.

Figure 41. Cascade Renewable Transmission Project



4.6.8 Transmission options summary

Table 16 provides a summary of the seven transmission options discussed above and their assumptions used for portfolio analysis.[87] PGE will continue to review and refine these options as part of the 2026 CEP/IRP.

Table 16. Transmission options

Project	COD[88]	Generation Resource	MW Available to PGE	Summer Market Access (% of MW Avail.)	Winter Market Access (% of MW Avail.)	Real-Levelized Cost ($/kW-mo)
Bethel-Round Butte	2032	BPA Resources	3000	0%	20%[89]	$ 5.52
Harborton-Trojan	2035	BPA Resources	800	0%	0%	$ 5.61
Gateway	2035	Wyoming Wind	400	0%	100%	$ 8.17

[87] BPA Generation resources refer to all Proxy Resources located within Concentric Circle 2 (**Section 4.3.1 Concentric circles of transmission**), including: Wind Gorge, Wind SE WA, Solar CV, Solar MCMN, Solar Wasco, CV hybrids, and MCMN hybrids.
[88] Project Commercial Operation Dates (CODs) represent the greatest COD for the underlying transmission segments.
[89] Assumed equivalent to PGE's existing rights at the California Oregon Border (COB).

Project	COD[88]	Generation Resource	MW Available to PGE	Summer Market Access (% of MW Avail.)	Winter Market Access (% of MW Avail.)	Real-Levelized Cost ($/kW-mo)
SWIP-N	2035	Nevada Solar	400	0%	100%	$ 9.56
North Plains Connector	2038	Montana & North Dakota Wind	600	100%	100%	$ 9.83
Greenlink	2035	Nevada Solar	627	0%	100%	$ 9.98
Cascade Renewable Tx Project	2038	BPA Resources	1100	0%	0%	$ 12.13

4.6.9 Transmission cost assumptions

The U.S. Department of Energy (DOE) "National Transmission Planning Study" and data from the GRIP are the primary sources used to calculate cost estimates for both AC and DC transmission options. All AC options are modeled as 500 kV single-circuit lines estimated at $2,048,670/mi and all DC options are modeled as 500kV HVDC circuits estimated at $4,600,000/mi.[90,91] Additionally, the DOE study provides terrain multipliers for AC options that are used to scale per mile estimates.[92] Federal cost share of GRIP awards was then subtracted from the estimated cost of a transmission option, where applicable.[93] These assumptions along with a project's estimated transfer capacity are used to derive costs for incremental transmission lines, those uncommitted projects that would require PGE ownership. Costs estimated are based on publicly available data and should be interpreted as a general estimate of the direct cost of line construction and do not account for additional development costs such as profit, balance of plant, permitting, procurement, and overheads.

Some transmission options required existing energized or committed projects to bring (wheel) energy home to PGE's service territory. Additional costs to wheel energy for such segments are included in the total cost for an option. The assumed rate for a wheel is $1.96 /kW-mo, based on BPA Point-to-Point Scheduling, System Control and Dispatch (PTP + SCD) costs for 2024. Lastly,

[90] U.S. Department of Energy. *The National Transmission Planning Study*. Ch 3. p.127.
[91] U.S. Department of Energy. The National Transmission Planning Study. Ch 3. p.70.
[92] Terrain multipliers are not identified for HVDC projects. Public information on project specific costs for HVDC options was used to calculate terrain multipliers for those HVDC projects.
[93] https://www.energy.gov/gdo/grid-resilience-and-innovation-partnerships-grip-program-projects.

all projects are assumed to carry a $4.81 /kW-mo real-levelized cost for operations and maintenance in 2024 dollars.

Chapter 5. Resource options

There are many resource options to be considered as PGE makes the energy transition to a decarbonized system. For analysis, PGE identifies all technologically and commercially feasible generation resource options. The economics of resources represent a crucial element of dynamics within IRP analyses for evaluating the characteristics of resources that could plausibly be deployed in the region. This chapter describes relevant costs and benefits associated with each resource assessed in this analysis update. These dynamics drive the decisions in portfolio analysis for evaluating resource options, optimizing for costs and benefits. Resource comparisons that can occur outside portfolio analysis are also visualized on a net cost basis.

Key Highlights

- Resource costs have increased, primarily driven by fixed costs in the current planning environment, with different resources providing disparate benefits in either energy generation, capacity, or storage capabilities. The potential effect of a reduction in tax credits is investigated.
- The inclusion of non-cost-effective Distributed Energy Resources (DERs) provides insight into how these resources can play an enhanced role in a decarbonized future.
- Community Benefits Indicator (CBIs) assumptions have been expanded and refined to better incorporate stakeholder feedback and provide measurable metrics across resilience, health, environmental impacts, energy equity, and economic impacts.

Developments Since 2023 IRP

This Update includes several key changes to resource economic assumptions including updated financial parameters; an adjusted electricity price forecast methodology incorporating forward price curves through 2028; updated supply-side resource costs; and refined capacity contribution values evaluated for 2030 using the Sequoia model. Further, portfolio sensitivity analysis considers current uncertainties regarding federal-level policies, including analysis without clean energy tax credits.

Additionally, the Update incorporates a new North Dakota wind resource option enabled by potential participation in the North Plains Connector transmission project and pushes back the earliest assumed availability for Oregon offshore wind to 2036 due to delays in the BOEM lease auction process.

Strategic Implications

These changes lead to several important implications for resource planning. The updated electricity price forecast shows significantly higher prices between 2025-2029, affecting the economic evaluation of resources. The reduced capacity contribution of

storage resources (particularly in winter) highlights a critical planning challenge regarding the interaction between storage and energy resources in a system with significant energy deficits. Importantly, the availability of federal clean energy tax credits has meaningful impacts on resource costs discussed in this chapter as well as total portfolio costs discussed in **Chapter 6**.

The North Dakota wind resource provides a new geographic diversity option, which is potentially valuable for addressing seasonal needs. Further, the updated CBIs framework provides a more comprehensive method for evaluating community benefits in resource decisions.

Staff Recommendations Incorporated

The Update addresses multiple Staff recommendations from LC 80 Order 24-096. For CBRE actions (Staff recommendation #1), PGE added a Small-Scale Renewable (SSR) proxy resource to model compliance with the 10 percent requirement. Regarding energy efficiency, PGE collaborated with Energy Trust of Oregon to develop guiding principles for complementary funding and establish funding targets with reporting requirements (Staff recommendation #4). On energy/capacity actions, PGE conducted a Request for Information (RFI) for long lead-time resources (Staff recommendation #2) and presented findings in 2024.[94] PGE also advanced CBI integration into resource planning and expanded RECs discussion through stakeholder engagement (Staff recommendations #6 and #7).

5.1 Resource economics

PGE's resource planning conclusions regarding best available generation technology and forecasted costs are driven by resource cost and performance assumptions. The candidate supply-side resources considered for portfolio construction in this Update are the same as those evaluated in PGE's 2023 CEP/IRP except for two changes that are discussed below. This section provides revisions to several key components of resource economics. Some of these updates result from updates to inputs, financial assumptions, and resource costs. These values flow into the portfolio analysis presented in **Chapter 6 Resource plan**.

5.1.1 PGE financial parameters

This Update uses revised financial parameters as of June 2024, which are summarized in **Table 17**.[95]

[94] PGE RFI Key Insights presentation, December 2024, https://assets.ctfassets.net/416ywc1laqmd/2GF5BwVt9cR1MXtEpn6fli/e719ec6879183abd984928db360fe410/RFI_slides_jdg_web_1197.pdf.

[95] Given the lead time for analysis, June 2024 represents the most recent financial parameter snapshot practicably possible for inclusion.

Table 17. 2025 IRP Update Financial Parameters

Component	Value
Composite Income Tax Rate	27.50%
Incremental Cost of Long-term Debt	5.79%
Long-term Debt Share of Capital Structure	50.00%
Common Equity Return	9.50%
Common Equity Share of Capital Structure	50.00%
Weighted Cost of Capital	7.65%
Weighted After-Tax Cost of Capital	6.85%
Long-Term General Inflation	2.04%

5.1.2 Supply-side resource costs

As mentioned above, the incremental supply-side resources considered in this Update are generally consistent with those evaluated in PGE's 2023 CEP/IRP. National Renewable Energy Laboratory (NREL) and Energy Information Administration (EIA) research still serves as the source for resource cost and performance parameter information. In this Update, PGE is generally using supply-side resource information from two sources:

- The NREL 2024 Annual Technology Baseline (ATB) updated in July 2024.[96]
- The EIA-commissioned Sargent & Lundy report, "Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies" released January 2024.[97]

These two reports represent the most recent updates from NREL and EIA, respectively, at the time of PGE's analysis in this Update. **Table 18** provides a summary of these assumptions by resource. Additional resources that PGE views as potentially available post-2030 are discussed below in **Section 5.6 Long lead-time resources**.

Table 18. Supply-side resource assumptions for portfolio construction - 2028 COD (2025$)

Resource	CF / RTE (%)	O/N Capital[98] ($/kW)		Fixed Costs[99] ($/kW-yr)	LCOE[100] ($/MWh)	
		IRP	Update		IRP	Update
Wind Gorge	44%	1,609	1,643	118	28	31

[96] NREL (National Renewable Energy Laboratory). 2024. 2024 Annual Technology Baseline. Golden, CO: National Renewable Energy Laboratory, https://atb.nrel.gov/.
[97] https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf.
[98] Overnight capital – is the upfront cost to construct the resources without consideration for the cost of funds during construction, includes interconnection costs but does not include the cost of incremental transmission unless otherwise noted.
[99] Real levelized fixed cost – is the annualized fixed cost (capital and operating) of the resource across the assumed economic life, in constant year dollars.
[100] Levelized cost of energy – is the annualized cost of the resource on a per MWh generated basis.

Resource	CF / RTE (%)	O/N Capital[98] ($/kW) IRP	O/N Capital[98] ($/kW) Update	Fixed Costs[99] ($/kW-yr)	LCOE[100] ($/MWh) IRP	LCOE[100] ($/MWh) Update
Wind MT	42%	1,560	1,531	136	32	36
Wind SE WA	42%	1,597	1,604	118	30	33
Wind WY[101]	44%	-	1,531	103	125	338
Wind ND[102]	41%	-	1,560	143	-	371
Solar Christmas Valley (CV)	27%	1,269	1,453	145	42	62
Solar McMinnville (MCMN)	21%	1,324	1,491	146	60	78
Solar Wasco	25%	1,269	1,453	145	45	65
Solar Mead[103]	32%	1,269	1,503	155	184	389
CV hybrid 1	-	2,278	2,912	280	212	112
CV hybrid 2	-	1,772	2,182	215	131	84
MCMN hybrid 1	-	2,329	2,982	285	303	146
MCMN hybrid 2	-	1,824	2,236	219	192	109
2-hour battery	86%	800	990	94		
4-hour battery	86%	1,212	1,617	153		

A pattern of increased costs for resources is observable in **Table 18**. Overnight capital costs have increased for nearly all resource technologies. Forecasted capital costs for storage resource have increased by over 30 percent which contributes to higher portfolio costs as analyzed in the Preferred Portfolio described in **Section 6.2**. Resource costs for solar resources have also increased significantly while increases in costs for wind resources is more modest.

Cost increases across generation and storage technologies may be driven by many factors including macro-economic concerns related to inflation, disrupted supply chains, and strong demand. The resource cost assumptions do not directly consider emerging issues such as federal policy uncertainties, variations in the macroeconomic environment (e.g., inflation, recessions), or the status of international trade agreements (e.g., duties or tariffs). Instead, a range of potential resource cost outcomes, including low-, reference-, and high-cost cases, are considered in portfolio construction.

5.1.2.1 Resource-specific updates

1. Onshore wind

A North Dakota-sited wind resource is added to the set of resources considered in portfolio construction for this Update. PGE's potential participation in the North Plains Connector (NPC)

[101] LCOE includes the cost of incremental transmission.
[102] LCOE includes the cost of incremental transmission.
[103] LCOE includes the cost of incremental transmission.

transmission project enables access to this resource. See the discussion of the NPC in **Section 4.6.5 North Plains Connector**. This resource is located near the eastern terminus of the NPC. Overnight capital cost estimates are based on EIA research. PGE's analysis assumes an earliest availability date of 2032. Other onshore wind resources in this Update are consistent with those considered in PGE's 2023 CEP/IRP.

2. Offshore wind

On September 27, 2024, the Bureau of Ocean Energy Management (BOEM) announced a delay in the auction for potential lease areas offshore Oregon due to "insufficient bidder interest at this time."[104] Just one of the five qualified companies indicated bidding interest in the planned auction. The auction for two lease areas was planned for October 15, 2024. As a result of these delays in the lease auction process, the earliest assumed availability for Oregon offshore wind is moved to 2036 (from 2032 in PGE's 2023 CEP/IRP) due to this delay in development opportunity.

5.1.3 Tax credit sensitivities

The Reference Case in this 2023 CEP/IRP Update assumes the same tax credit environment for generation and energy storage resources as described in PGE's 2023 CEP/IRP.[105] This environment was shaped by the federal governments passage of the Inflation Reduction Act (IRA) in 2022. Key assumptions for modeling include:

- Tax credits continue across the analysis period for modeling purposes. This assumption removes the possibility of tax credit expiration influencing the portfolio construction process.
- Non-emitting generating resources qualify for 100 percent of the production- or investment-based tax credits (PTC and ITC, respectively).
- Standalone storage resources qualify for 100 percent of the investment-based tax credit without the need for normalization.
- Tax credits are assumed to be fully monetized in the year they are generated.

To help understand the potential impact on resource economics of changes to this set of assumptions, two sensitivities are considered:

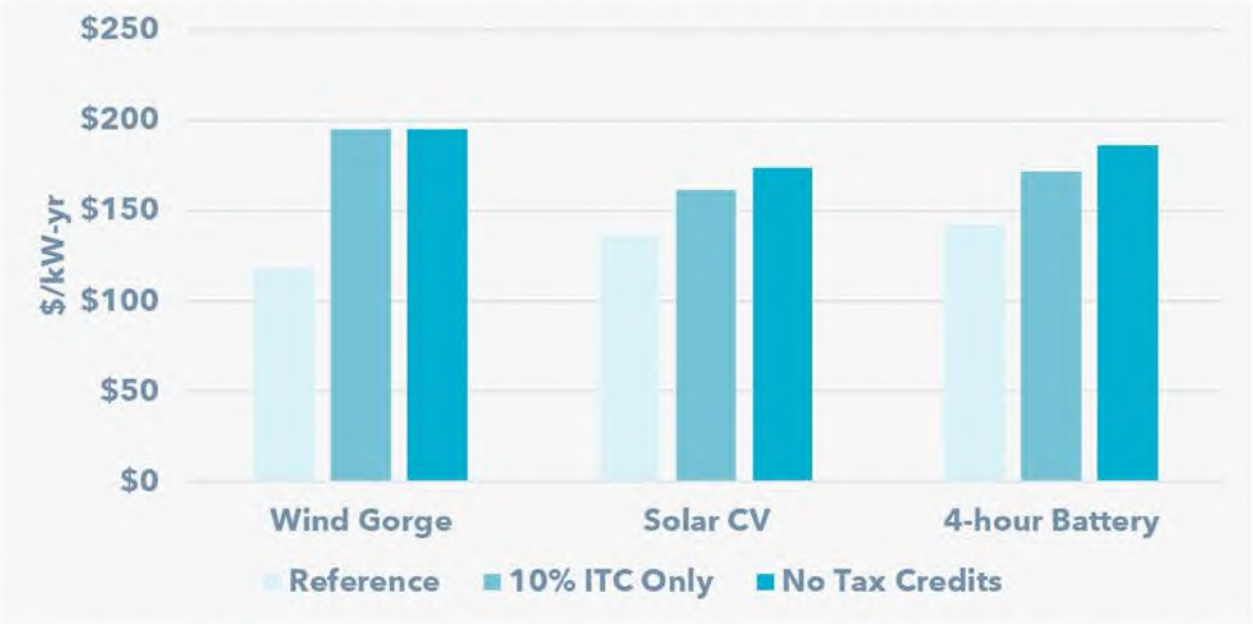
1. Federal tax credit policy reverts to a roughly "pre-IRA" state:
    a. The PTC is not available for new non-emitting generating resources, and
    b. The ITC is available at a rate of ten percent for solar and energy storage resources.
2. Federal policy removes tax credits entirely for new non-emitting generating and energy storage resources that are placed in service after December 31, 2028.

Resource costs relative to the Reference Case in both scenarios as summarized below in **Figure 42**. The sensitivities assume that credits continue to be fully monetized when generated for

[104] https://www.boem.gov/newsroom/press-releases/boem-postpones-oregon-offshore-wind-energy-auction.
[105] Tax credits are discussed in Section 2.1 and 8.1.6 of the 2023 CEP/IRP (see pages 42 and 173).

purposes of determining resource costs. Removing the PTC as modeled from a generic wind resource results in an approximately 64 percent increase in the cost of that resource on a real-levelized basis. Reducing the ITC to ten percent increases solar and battery storage resource costs by approximately 19-20 percent; removing the ITC entirely results in a further ten percent increase in costs for these resources. This analysis assumes wind resources are not eligible for the ITC and, thus, the resource cost is unchanged in the "10 percent ITC Only" and "No Tax Credit" sensitivities.

Figure 42. Tax credit scenario real-levelized costs 2030 COD (2025$/kW-year)



As is observed in **Figure 42**, the availability of federal tax credits has a significant impact on the assumed cost of generation and storage resources. Specifically, without the availability of federal tax credits through 2035 generation costs are expected to increase by as much as 64 percent and storage resources by 30 percent. The customer cost increases associated with changing these assumptions are significant and analyzed further in **Section 6.6 Federal tax credit availability scenarios**.

5.1.4 Electricity price forecast

OPUC Staff provided feedback on the 2023 CEP/IRP regarding the PGE electricity price forecast, which is used in the calculation of energy efficiency avoided cost data.[106] Between 2025 and 2029, the PGE electricity forward price curve (FPC) was significantly higher than PGE's fundamental price forecast. The fundamental price forecast is produced by PGE's IRP team in Aurora using forecasted supply and demand conditions across the WECC. The FPC used by IRP

[106] Public Utility Commission of Oregon. (2024, April 30). Staff report: Request for approval of energy efficiency avoided cost data to be used by Energy Trust (Docket No. UM 1893). https://edocs.puc.state.or.us/efdocs/HAU/um1893hau328091055.pdf

is the same as produced for the 2025 AUT. Staff recommended that the Energy Trust of Oregon use a blended price when calculating the avoided costs of energy efficiency.

In response, PGE adjusted the methodology used in the electricity price forecast for this Update to align with Staff's recommendation in UM 1893. For the years 2025 through 2028, the PGE electricity FPC replaces the long-term fundamentals price forecast. After 2029, the IRP electricity price forecast is based on the fundamentals forecast. In 2029, the price forecast is calculated as the hourly average blend of the two forecasts for each of the 39 price futures. **Figure 43** shows the results of incorporating the FPC into the IRP price forecast compared to the fundamentals price forecast in the 2023 CEP/IRP and the 2023 CEP/IRP Update.

Figure 43. Reference IRP Price Forecasts from 2025 - 2044

5.1.5 Supply-side resource energy value

PGE uses Aurora to estimate the energy value of dispatching existing generating resources, contracts, and candidate new resources using electricity prices and associated risk variable inputs from each price future.

The Reference case energy value and range of outcomes across the simulated price futures for each resource are summarized in **Table 19**. These values are levelized across each resource's economic life, for resources with 2028 commercial operation dates.

Table 19. New resource option energy values (2028 COD)[107]

Resource	Levelized energy value (2025$/MWh) Reference case	Range
Solar CV	$23.51	$15.36 - $34.54
Solar MCMN	$22.52	$14.77 - $33.12
Solar Wasco	$22.03	$14.45 - $32.41
Wind Gorge	$27.70	$17.91 - $41.19
Wind MT	$32.53	$20.81 - $47.98
Wind SE WA	$30.03	$19.28 - $44.41
Wind ND	$31.05	$19.98 - $45.86
CV hybrid 1	$28.72	$18.96 - $40.70
CV hybrid 2	$26.00	$18.02 - $37.87
MCMN hybrid 1	$29.33	$19.47 - $41.34
MCMN hybrid 2	$25.81	$17.97 - $37.47

Energy values presented here for a 2028 COD are higher on average than those in the 2023 CEP/IRP by roughly 10 percent to 35 percent, depending on the resource. This is driven in part by the upward change in the electricity price forecast for early model years, as described in **Section 5.1.4 Electricity price forecast**.

5.1.6 Resource capacity contribution

Resource capacity contribution values were discussed in Section 10.5 of PGE's 2023 CEP/IRP. Please also see the related discussion in **Section 3.4 Capacity need** of this Update. The effective load-carrying capability (ELCC) identifies the percentage of a resource's nameplate capacity that can be depended upon when planning for resource adequacy. For example, the 100 MW nameplate capacity of a 4-hour battery may have an ELCC of 22 percent in the winter. This means that the 100 MW nameplate capacity of a 4-hour battery contributes 22 MW (100 * 0.22) towards reducing system capacity needs. If the starting system has a winter capacity need of 200 MW, after adding a 100 MW 4-hour battery, the new capacity need will be 178 MW (200 MW of need, less 22 MW of capacity).

For this Update, the capacity contributions of resources summarized in **Table 20** are evaluated in the year 2030 using Sequoia. The analysis uses the same snapshot of loads and resources as used for the updated capacity need assessment discussed in **Section 3.4 Capacity need**. Since the publication of the 2023 CEP/IRP, model updates were made to Sequoia including load forecasts, QF assumptions, and RFP proxy additions (**Section 3.4.2 Changes to modeling capacity need**). These updates reduced the 2026 capacity need, the year ELCCs were evaluated

[107] Ranges reflect upward and downward semi-deviations around the Reference Case across the market price futures.

in the 2023 CEP/IRP, to 47 MW in summer and 0 MW in winter. 2030 was elected as a representative year with sufficient need to test the capacity contributions of proxy resources for the 2023 CEP/IRP Update. Additionally, as part of the 2023 CEP/IRP Update it is assumed that proxy resources will acquire firm transmission equal to 75 percent of the nameplate capacity. This change reflects an attempt to align transmission modeling assumptions with state resource adequacy requirement (e.g. WRAP) and future modeling.[108]

A major finding of the Update is the reduction in ELCCs of storage resources. The cause of this reduction is due in part to an additional 775 MW of storage resources in the system with the RFP Proxy.[109] Second, the ELCC of storage resources is dependent on the amount of energy in the system, for which the 2030 base energy system has a significant energy deficit and is pronounced in winter as discussed in **Section 3.3 Energy need**. PGE considers the unique planning challenge presented by the interactions between storage and energy to be a priority item for review in future integrated resource plans. **Section 6.2.3 Preferred Portfolio resource adequacy testing** expands on the current planning framework, the concern it presents in Preferred Portfolio results, and approaches to address these concerns as part of the 2023 CEP/IRP Update and future planning efforts. Additionally, long-duration storage (LDS) was not assumed available for portfolio expansion due to the lack of commercially proven projects, as such the ELCCs for this resource are not included below. However, **Section 6.2.3 Preferred Portfolio resource adequacy testing** provides a preliminary view of the benefit LDS could provide to PGE's system and motivates further analysis of this and other emergent technology as part of the 2026 CEP/IRP.

Table 20. ELCC values for portfolio construction in year 2030, incremental 100 MW nameplate

	Summer		Winter	
Resource	Firm	Conditional Firm	Firm	Conditional Firm
Wind Gorge	40%	34%	28%	28%
Wind MT	24%	17%	58%	55%
Wind SE WA	17%	13%	43%	39%
Wind WY	32%	20%	59%	51%
Wind ND	30%	19%	54%	51%
Solar CV	23%	10%	21%	21%
Solar MCMN	26%	13%	21%	11%
Solar Wasco	27%	13%	18%	18%
Solar Mead	14%	10%	30%	30%
CV hybrid 1	76%	50%	36%	36%
CV hybrid 2	56%	34%	25%	26%

[108] See LC 80 - Attachment 2. Staff Expectations for Future IRP-Transmission Modeling, and UM 2274 SMM Condition 5.

[109] Analysis of the change in storage resource ELCCs discussed in Jan. 8th 2025 CEP/IRP Roundtable 25-1.

MCMN hybrid 1	80%	57%	32%	32%
MCMN hybrid 2	61%	34%	28%	28%
2-hour battery	31%		14%	
4-hour battery	46%		22%	

5.1.7 Comparison of resource capacity contribution to 2023 CEP/IRP

As discussed in the section above, the updates that PGE made to resource adequacy modeling, including changes to the underlying portfolio, have resulted in updated proxy resource capacity contributions. These changes can have important impacts on portfolio analysis. To understand the potential key drivers of changes in portfolio outcomes from the 2023 CEP/IRP, this section provides a comparison between the updated ELCCs and those from the 2023 CEP/IRP. Comparisons between ELCCs from the 2023 CEP/IRP and this Update for Summer and Winter are shown in **Figure 44** and **Figure 45**.

Figure 44 shows that generally Summer ELCCs for Proxy resources have decreased since the 2023 CEP/IRP. This decrease is attributed to the assumed 75 percent transmission availability assumption, discussed in the section above, and due to the additional storage and solar resources modeled in the system as part of the 2023 RFP Proxy resource discussed in **Section 3.2.2 2023 RFP proxy**.

Figure 45 shows the same general trend of lower ELCCs exists in Winter. However, there is a modest increase in the value of solar proxy resources, attributed to the added benefit that midday energy plays in decreasing the likelihood that winter reliability events span across the AM and PM peaks.[110]

Figure 44. Select ELCC Comparison - Summer, Firm Transmission

[110] See **Section 6.2.3.1 Energy sensitivity adequacy assessment of Preferred Portfolio** for more discussion on the value of energy in meeting winter reliability challenges.

Figure 45. Select ELCC Comparison - Winter, Firm Transmission

5.1.8 Resource capacity value

The capacity value is a theoretical construct that uses the net cost of capacity and a resource's capacity contribution to derive a dollar value.

Using the $237/kw-yr described in **Section 6.7 Net cost of capacity resources** as the cost of capacity, with the same approach as in PGE's 2023 CEP/IRP, the capacity value of a resource at (nameplate) is:

$$Capacity\ value\ of\ resource\ A\ =\ Capacity\ contribution\ of\ resource\ A\ (ELCC\ \%)\ *\ \$237/kW-yr$$

While not used directly for portfolio analysis in this Update, the resulting capacity value is useful for the purpose of comparing resources or for calculating the administratively determined avoided cost payments for resources procured outside of competitive or negotiated processes. This value has increased meaningfully compared to the 2023 CEP/IRP driven mainly by updated assumptions regarding higher fixed costs as well as increased capacity which reduced ELCCs. This net cost of capacity value is an illustrative metric and is not directly included in portfolio analysis.

Table 21 and **Table 22** summarize the capacity values of resources considered in this Update. For capacity resources in **Table 21**, the ELCC and corresponding capacity value ($/kW-yr.) indicate the amount of capacity required of each resource to provide an incremental 100 MW of capacity contribution to the portfolio. Emergent technologies, such as LDS, geothermal, hydrogen storage, nuclear, etc. are not detailed below due to a current lack of commercially proven projects. As noted above, **Section 6.2.3 Preferred Portfolio resource adequacy testing** suggests these resources may be valuable additions in PGE's portfolio due to winter reliability challenges and motivates the need for a more thorough analysis of such emergent technologies in the 2026 CEP/IRP.

Table 21. Capacity Resource ELCCs and Capacity Values

Resource	Annual ELCC 100 MW capacity contribution	Capacity value (2025$/kW-yr.)
4-hour battery	32%	76
6-hour battery	43%	101
Wind SE WA	12%	29
Solar CV	16%	37
CV hybrid 1	55%	129
MCMN hybrid 1	55%	131

For energy resources in **Table 22**, the ELCC and corresponding capacity value ($/MWh) are shown corresponding to 100-megawatt average (MWa) addition sizes after accounting for the corresponding levelized capacity factors. The ELCC values reflect the effects of the declining marginal ELCC curves.[111]

Table 22. Energy Resource ELCCs and Capacity Values

Resource	Annual ELCC 100 MWa energy addition	Capacity value (2025$/MWh)
Wind MT	35%	23
Wind Gorge	33%	20
Wind SE WA	18%	11
Solar CV	19%	19
Solar Wasco	17%	18
Solar MCMN	17%	22

5.1.9 Resource net cost

This section provides an overview of updates to Section 10.8 of PGE's 2023 CEP/IRP on resource net cost; combining a resource's cost, energy value, flexibility value, and capacity value results in the "net cost". As discussed in Section 10.8.1 and 10.8.2 of PGE's 2023 CEP/IRP, the net cost of capacity and energy resources can be a useful tool for comparing resources on similar terms, though these results are not used directly in portfolio analysis. The net costs displayed in this section are based on the formula in **Section 5.1.9 Resource net cost** above. Based on these illustrative results, the portfolio analysis in **Chapter 6 Resource plan** meets capacity needs more economically with energy resources in select years.

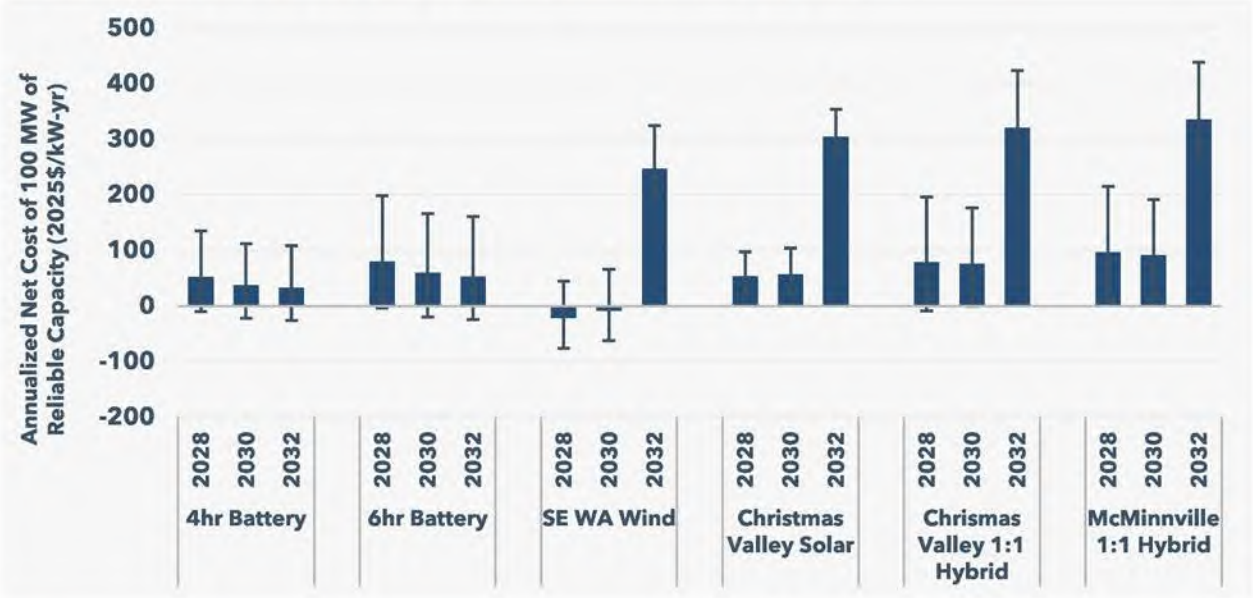
5.1.9.1 Net cost – capacity resources

Figure 46 illustrates the net cost in $/kW-yr of providing 100 MW capacity contribution to the portfolio from various select resources. From this snapshot, standalone batteries appear to be

[111] The annual ELCCs shown in this table are calculated with the average of the seasonal ELCC and are for informational purposes and meant to be directional indicators of capacity value. The actual value of capacity is estimated within portfolio analysis and is dependent on seasonal ELCCs.

the least-cost means to provide capacity to the portfolio in the near-term. These net cost of capacity values represent the total cost less energy, flexibility, and capacity contribution values. Negative net costs imply the given resource for that COD is less expensive than the portfolio-blended cost of capacity described in **Section 6.7 Net cost of capacity resources**. However, in reality, the resource may not yet be available given transmission constraints. Broadly, the relative net costs highlight the order of selection. For example, with transmission constraints beginning in 2032 for some resources, based on the information in **Figure 46**, a model adding capacity while minimizing cost would select battery resources before any of the transmission expansion options.

Figure 46. Net cost of 100 MW of capacity contribution by COD



5.1.9.2 Net cost – energy resources

Similarly, **Figure 47** summarizes the net cost in $/MWh of 100 MWa incremental energy contribution to the portfolio from a selection of variable energy resources. These net cost of energy values represent the levelized cost of energy less energy, flexibility, and capacity contribution values. Given the CODs shown, these net costs do not begin to include transmission access and associated costs until 2032 for select resources. This meaningfully increases costs in later years once transmission access is deemed available and this premium highlights why distribution-connected resources may become increasingly cost-competitive in a model, despite having higher fixed costs than their supply-side counterparts.

Figure 47. Net cost of 100 MWa generation by COD

While net costs of new resources provide helpful insights for understanding the economic tradeoffs between specific resource actions, this simplistic view of resource economics neglects risks associated with future uncertainties and potential interactions between resources and constraints. These are more thoroughly investigated through portfolio analyses described in **Chapter 6 Resource plan**.

5.2 Distributed energy resources (DERs)

PGE develops a forecast of DER adoption and hourly load impact on a regular basis. This DER forecast provides insights on how much market-based DER adoption will impact both PGE's bulk and distribution systems. It also informs how much cost-effective demand response can be made available to shape and shift load on the bulk system. As such, the DER forecast informs PGE's planning processes, including its Distribution System Plan (DSP) and the IRP. This section provides a brief description of the approach used and results from the DER forecast.

The DER forecast uses PGE's AdopDER software to model the adoption of over 60 DER technologies and technology combinations. The software uses a current, point-in-time snapshot of data from PGE systems that describes the characteristics of each PGE service point: building type and vintage, heating and cooling system, vehicle weight class(es) and fuel(s), and interconnected solar PV and storage. AdopDER also accounts for customer growth across PGE's service territory to simulate the eligibility, adoption, and load impacts for each DER over a 20-year forecast horizon through calendar year 2044.

From this starting point, AdopDER simulates both the market adoption of passive DERs and expected customer participation in current and future demand response programs–representing achievable potential within a potential study framework. For this update to PGE's 2023 CEP/IRP, three adoption scenarios (reference, high, and low) were modeled using varying inputs such as

cost assumptions, adoption trends, and policy signals. The outputs reflect how DER deployment is shaped by evolving market, regulatory, and customer dynamics.

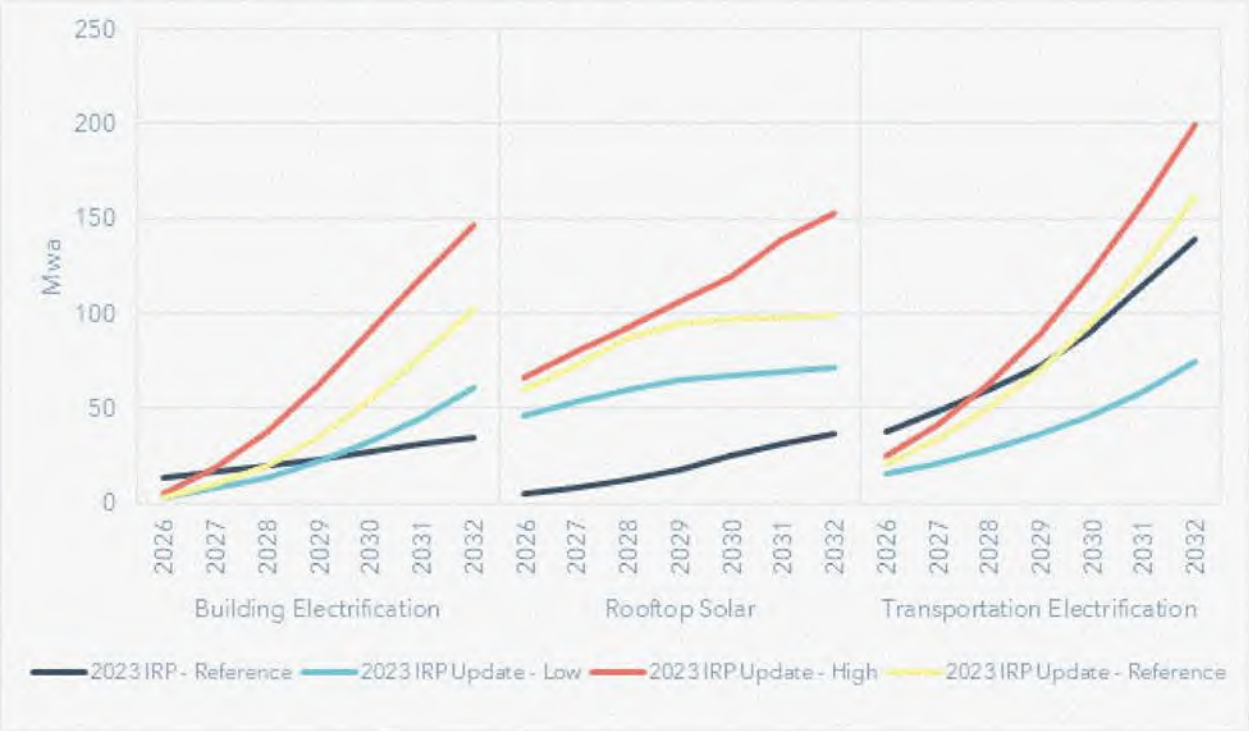
AdopDER calculates cost-effectiveness metrics for each demand response resource and modeling of these resources in the IRP is handled in distinct ways depending on whether a resource is deemed to be cost-effective, or non-cost-effective, in AdopDER. Cost-effective measures are assumed to be adopted, with their capacity benefits reducing PGE's forecasted capacity need. Measures deemed to be non-cost-effective in AdopDER are made available in portfolio analysis, competing on an economic basis for selection against supply-side resource options. To consider the potential of the entire demand response supply curve, the IRP Action Plan sets a demand response target that includes all of the cost-effective measure and any additional non-cost-effective resources identified through portfolio analysis.

This Update reflects the best available DER forecasts at the time of analysis, including results from the August 2024 AdopDER run. AdopDER is a dynamic tool, and its outputs are sensitive to underlying assumptions–such as changes in federal and state policy, economic conditions, and regional adoption patterns. These inputs are continually refined as new data becomes available. All DER forecasts are currently being updated as of May 2025 and will be incorporated into the forthcoming Transportation Electrification Plan, Distributed Systems Plan, and Flexible Load Multi-Year Plan.

5.2.1 Passive DERs

Passive DERs are represented in IRP modeling using three categories: distributed solar (PV), transportation electrification (TE) and building electrification (BE). These cost-effective DER shapes are not incorporated into the PGE load forecast regression as outlined in **Section 3.1 Econometric load forecast**. **Figure 48** shows the reference case values from the 2023 CEP/IRP are included shows the passive DER shapes by category by year (2026-2032) for the low, base and high case scenarios used in the 2023 CEP/IRP Update.

Figure 48. Passive DER shapes by category by year



5.2.1.1 Distributed solar (PV)

The annual adoption of distributed solar PV is projected to experience significant growth through the late 2020s before leveling off in the early 2030s. Multiple factors drive this growth trajectory: decreasing technology costs, rapid technological advancements, supportive state policies, and increasing customer environmental awareness. However, this trend is anticipated to begin to flatten for two primary reasons. First, key financial incentives like the Residential Clean Energy Credit and Investment Tax Credit–currently stimulating adoption–will gradually phase down after 2032, with credit percentages decreasing to 26 percent in 2033 and 22 percent in 2034, before potentially being eliminated. Second, as residential customers continue to drive the majority of distributed solar PV adoption, the diminishing availability of suitable rooftops will create a natural constraint on future growth as the most optimal installation sites become saturated. The results from the AdopDER forecast for Distribute PV do not consider risks associated with the more rapid phasing out of tax credits as discussed in **Section 2.5 Federal administration changes**.

5.2.1.2 Transportation electrification (TE)

The transportation electrification policy assumptions include the impact of the 2022 Advanced Clean Cars II rule for light-duty vehicles, which requires that auto manufacturers meet 100 percent of the market share of new vehicles with zero-emission battery electric and plug-in

hybrid electric models by 2035.[112] Similarly, medium- and heavy-duty vehicles follow the 2021 Advanced Clean Truck rules, which set aggressive electrification targets for this vehicle segment.[113] The DER forecast also accounts for PGE customers and their known fleet electrification plans (i.e., a customer has plans to electrify 100 percent of its fleet by year 2028).

In the 2023 CEP/IRP Update forecast, PGE expects a total of 270,000 light-duty battery electric vehicles by 2030, predominantly in the residential sector, and approximately 80,000 medium and heavy-duty battery electric vehicles. From these vehicle estimates, PGE expects the annual transportation electrification load to achieve 95 MWa by 2030.

Gross transportation electrification load does not account for the potential impact of associated demand response programs such as time-of-use or managed charging programs. These impacts are instead captured under Demand Response or Flexible Load resources (e.g., direct load control programs).

5.2.1.3 Building electrification (BE)

Building electrification has significant potential to both decarbonize the economy and increase the amount of electric load that PGE needs to serve its customers' needs. In the DER forecast, fuel switching from fossil fuels to electric space heating, water heating, and/or cooking technologies in existing buildings and the new construction sector drives the building electrification forecast. The rate at which these customers electrify their end-use systems includes the expected impact of the 2022 Inflation Reduction Act legislation.

Like transportation electrification, gross building electrification load across varying adoption scenarios, not accounting for the potential impact of associated demand response and direct load control programs.

5.2.2 Cost-effective demand response

Cost-Effective (CE) DER resources are included in PGE's assessment of system need. **Section 3.4 Capacity need** details PGE's approach to estimating system need for the 2023 CEP/IRP Update using PGE's resource adequacy assessment model, Sequoia. As part of estimating system need, Sequoia utilizes estimates from PGE's AdopDER model. AdopDER simulates market adoption of passive DERs and the expected participation of customers in current and potential demand response programs.[114] AdopDER accounts for key site-level factors such as access to garage parking, breaker space and equipment turnover to determine the technical, achievable, and economic potential. Twenty CE DER resources are modeled as part of the 2023 CEP/IRP Update, the same number as used in the 2023 CEP/IRP. Two inputs from AdopDER are used to estimate

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[112] Final rule amendments to OAR Chapter 340, Division 257 adopted by the Oregon Environmental Quality Commission in Order DEQ 23-2022 (December 19, 2022), https://www.oregon.gov/deq/rulemaking/Documents/DEQ232022.pdf.

[113] Final rule amendments to OAR Chapter 340, Division 257 adopted by the Oregon Environmental Quality Commission in Order DEQ 17-2021 (November 17, 2021), https://records.sos.state.or.us/ORSOSWebDrawer/Recordhtml/8581405.

[114] For more information on AdopDER reference 2023 CEP/IRP Chapter 6.2 - Distributed Energy Resource (DER) impact on load

the hourly effect of each CE DER in Sequoia: hourly shape and program size by month. Hourly shapes are scaled across the planning horizon based on program size, resulting in estimated hourly contributions of each CE DER resource which grow with forecasted increases in program participation. Further, CE DER contributions are estimated for the three need futures (Low/Reference/High) used in the 2023 CEP/IRP Update. **Table 23** provides a summary of program size of CE DER resources in the 2030 Reference need future. In total, there are 1269 MW of capacity from CE DER resources on average in 2030, a 181 MW net increase in capacity from the 2023 CEP/IRP Addendum: System Need and Portfolio Analysis Refresh. The largest change in program participation is in the Rooftop Solar program, which is estimated at 668 MW of capacity on average in 2030, a 165 MW increase from the estimates used in the 2023 CEP/IRP Addendum.

Table 23. Monthly Average Program Size of CE DER Resources - 2030 Reference Case (MW)

Program	2023 CEP/IRP Update	2023 CEP/IRP Addendum	2023 CEP/IRP
Rooftop Solar	668	503	206
Building Electrification	96	51	33
Light Duty EV	95	149	101
Energy Partner Curtailment (Summer)	92	52	52
Smart Thermostat (Summer)	76	65	65
Energy Partner Curtailment (Winter)	68	46	46
Time-of-Use (Summer)	41	30	30
Smart Thermostat (Winter)	39	35	35
Time-of-Use (Winter)	23	15	15
Peak-time Rebates (Summer)	22	43	43
Peak-time Rebates (Winter)	18	28	28
Multi-Family Water Heater (Winter)	18	41	41
Multi-Family Water Heater (Summer)	10	26	26
Utility Controlled Storage (Commercial)	3	3	3
Utility Controlled Storage (Residential)	0	0	0
Customer Controlled Storage	0	0	0
EV Load Control (Winter)	0	0	0
EV Load Control (Summer)	0	0	0
Customer Controlled Storage	0	0	0
Utility Controlled Storage w/ PV	0	0	0
Total	**1269**	**1087**	**724**

Lastly, PGE adjusted AdopDER estimates of program size for years 2025-2026 to align values with PGE's Multi-Year Plan (MYP) forecasts for mature CE DER programs: Smart Thermostat, Peak-time Rebates, Time-of-Use, Energy Partner Curtailment, and Multi-family Water Heater.[115] The MYP provides more accurate short-term forecasts of eligible program adoption compared to AdopDER's bottom-up, locational approach. PGE aligned the AdopDER near-term forecasts with MW impacts from MYP to ensure consistency across all planning deliverables.

5.2.2.1 Dispatchable Stand-by Generation (DSG)

PGE's DSG program provides a valuable reliability benefit. The contingency reserves these customer-sited resources supply in the form of operating reserves free-up PGE's generating resources to serve load. Additionally, DSG resources can provide ancillary services in the form of frequency and demand response. This program was estimated to have little to no growth in the 2023 CEP/IRP and 2023 CEP/IRP Update, growing from approximately 109 MW in 2025 to 113 MW by 2030. However, more recent analysis of load growth from the industrial segment and data centers is expected to increase program participation by 120 MW.[116] Including growth from data centers as well as other C&I customers, the DSG program is expected to have 300 MW of nameplate enrollment by 2030. In anticipation of growth in the DSG PGE's rate Schedule 200 was updated to ensure customers are at least cost-neutral to participate, increasing the likelihood of enrollments and the ability of this program to avert situations that could lead to power quality problems for the power supply in the local region.[117]

5.2.3 Non-cost-effective demand response

The 2023 CEP/IRP Update includes updated quantity and cost assumptions for four bundles of non-cost-effective (NCE) DER resources. Updated values result from the August 2024 run of PGE's AdopDER model, used to forecast metrics for NCE DERs.[118,119] The four bundles are groupings of the same site-level measures as used in the 2023 CEP/IRP described in Section 8.2 - Additional distributed energy resources and Section 8.2.2 – Additional demand response. Each bundle represents similar DER programs based on dispatch characteristics and costs. **Figure 49** compares the available quantities of NCE DER resources in the 2023 CEP/IRP Update to those used in the 2023 CEP/IRP. The cumulative total quantity of NCE DER resources decreased by 40.39 MW in 2030, due largely to a 57 percent reduction in forecasted adoption of utility-controlled battery in the residential segment. The large reduction in residential utility-controlled battery is due to a slower adoption trend for these resource as estimated in the August 2024

[115] Flexible Load Multi-Year Plan 2025-2026

[116] OPUC Staff Report Docket No. Adv 1705 - Updates Schedule 200 Dispatchable Standby Generation to increase the Aid in Construction Allowance. These more recent estimates of DSG program size were not incorporated in the 2023 CEP/IRP Update due to timing in the analysis process. Estimates will be reviewed as part of the 2026 CEP/IRP planning cycle.

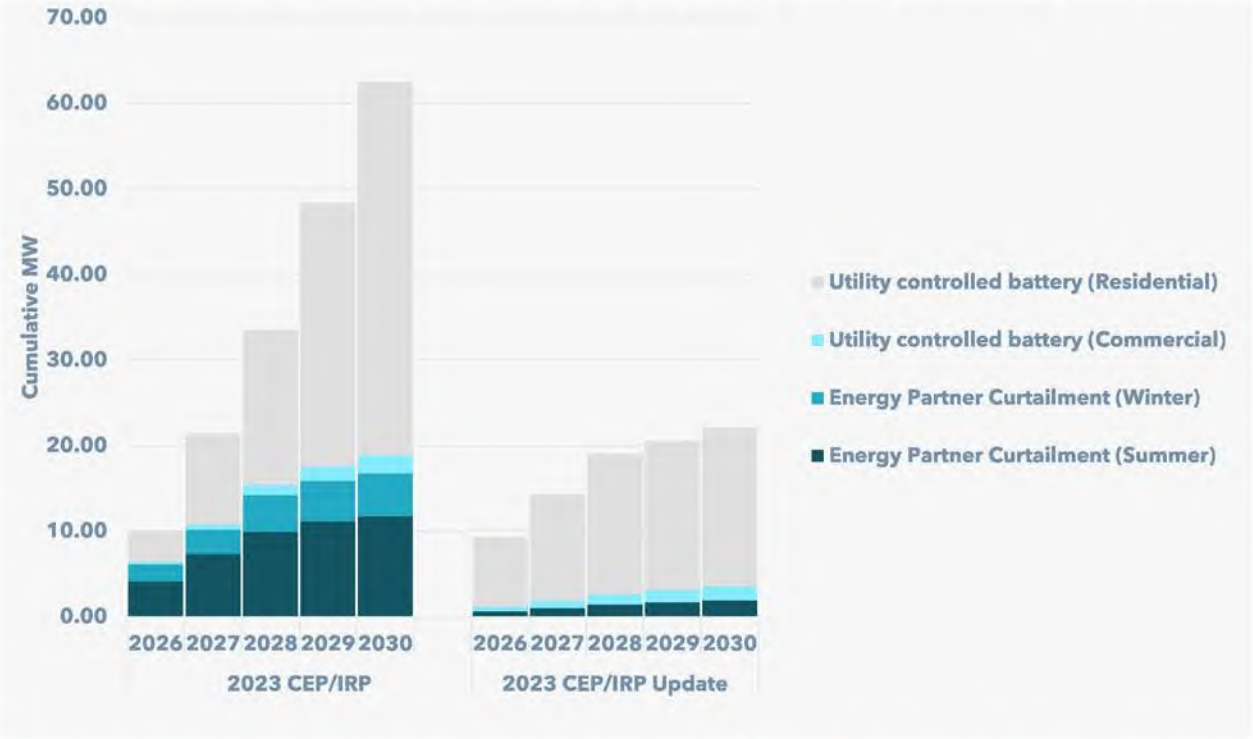
[117] PGE Rate Schedule 200

[118] For a more detailed discussion of AdopDER reference: 2023 CEP/IRP's Section 6.2 – Distributed Energy (DER) impact on Load

[119] These updates do not take into account UM 2141 updates approved after August 2024 (i.e., Feb. 2025 approvals)

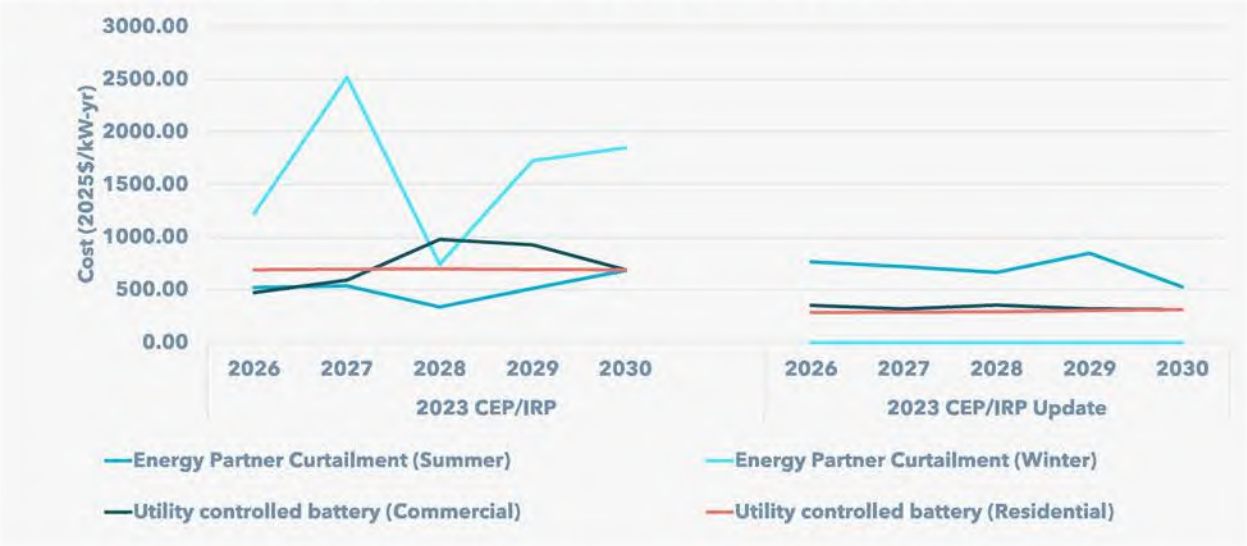
AdopDER run. Further, capacity from winter NCE Energy Partner Curtailment resources is non-existent in the 2024 AdopDER run, as the smart thermostat and cold storage curtailment programs previously bundled within are now considered cost-effective.

Figure 49. NCE DER Quantities Available in 2023 CEP/IRP and 2023 CEP/IRP Update



Cost assumptions were updated as part of the revised AdopDER results. Fixed costs for these NCE DER resources reflect weighted average site-level costs, including customer acquisition costs, upfront incentives, and upfront participation costs. Ongoing costs were also revised and included as variable costs for customers, incentives, and participants. **Figure 50** displays a comparison of costs from the 2023 CEP/IRP to values used in the 2023 CEP/IRP Update. Average costs across 2026-2030 for utility-controlled batteries in both commercial and residential segments decreased by approximately $380 /kW-yr, while average costs across the same period increased by $180 /kW-yr for summer Energy Partner Curtailment resources. Winter Energy Partner Curtailment costs are no longer reported as the estimated quantity available in the 2023 CEP/IRP Update is 0 MW, as described above.

Figure 50. Comparison of Updated NCE DER Costs (2025$/kW-yr)



5.3 Energy efficiency

PGE relies on the Energy Trust of Oregon (ETO) to identify energy efficiency measures available in the IRP using its resource assessment modeling tool. This modeling tool uses a cost-effectiveness screen on energy efficiency potential to forecast two metrics: (1) Cost-Effective (CE) energy efficiency measures and (2) Non-Cost-Effective (NCE) energy efficiency measures. The CE energy efficiency measures are incorporated into PGE's IRP load forecast and assumed to be acquired in IRP portfolio analysis. The NCE energy efficiency measures are incorporated into IRP's portfolio analysis and are considered as incremental resource additions based upon the aggregation of energy efficiency measures into discrete bins.

5.3.1 Cost-effective energy efficiency

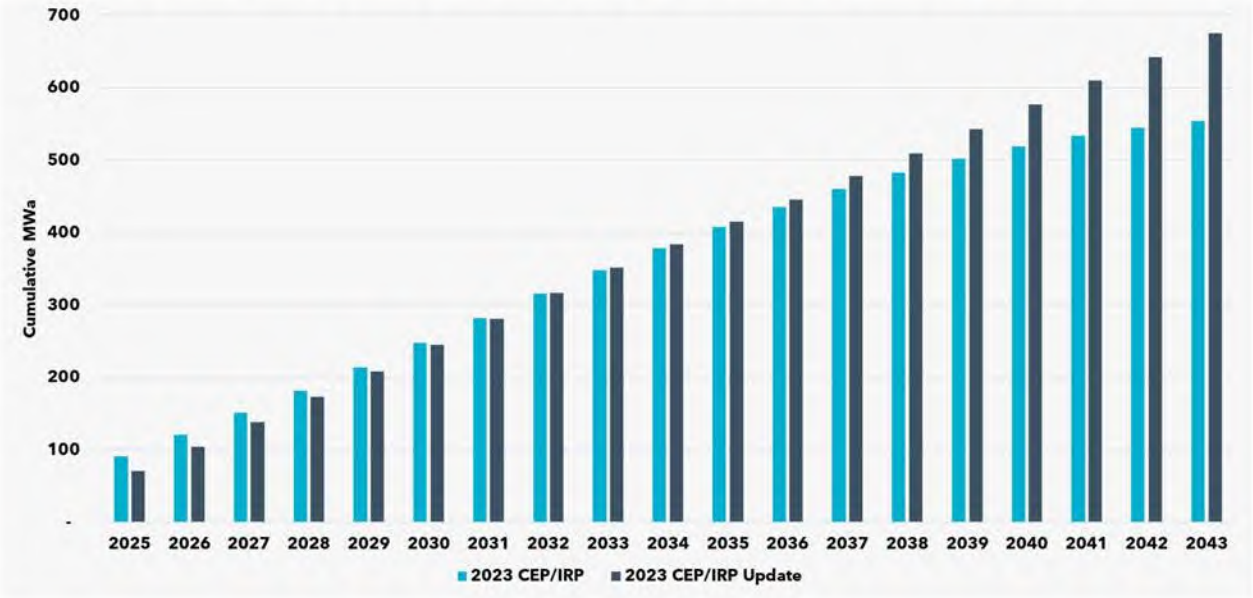
PGE receives a list of Cost-Effective (CE) Energy Efficiency measures that the ETO has found to pass its cost-effectiveness screening. The screening involves using a benefit-cost ratio to determine if the present value of benefits is equal to or exceeds the present value of the costs of the measure being evaluated. The CE Energy Efficiency forecasts are incorporated into the IRP load forecast as independent, or explanatory, variables in PGE's load forecast regression models.[120] For details on the CE achievable potential by end use and sector and final savings projections for CE energy efficiency measures, see the 2025 Resource Assessment Model provided by the Energy Trust of Oregon in **Appendix E**.

For this Update PGE incorporated an updated forecast of CE EE from the ETO. As shown in **Figure 51**, cumulative quantities of CE EE are forecast to be slightly lower through 2031 than in the 2023 CEP/IRP. Beyond 2031, CE EE quantities are increased relative to the 2023 CEP/IRP forecast, although the differences are relatively small until the late 2030's. By 2043, the updated

[120] The Energy Efficiency Savings forecast shared by the Energy Trust in November of 2023 was used as an input to the May 2024 load forecast.

forecast identifies 122 MWa more CE EE than was incorporated in modeling in the 2023 CEP/IRP. The main drivers of this increased potential CE EE savings are described in the 2025 Resource Assessment Model provided by the Energy Trust of Oregon in **Appendix E.**

Figure 51. Cost-effective energy efficiency in the 2023 CEP/IRP and IRP Update



5.3.2 Non-cost-effective energy efficiency

For PGE's 2023 CEP/IRP update, the ETO provides PGE with savings and levelized cost data for energy efficiency measures that do not pass the cost-effectiveness screening in the Resource Assessment Model. A summary of the ETO energy efficiency measures in the 2025 Resource Assessment Model provided by the Energy Trust of Oregon can be found in **Appendix E**. These Non-Cost Effective (NCE) measures are incorporated into IRP modeling via the PGE bundling methodology as candidate resources in Portfolio Analysis.

5.3.3 Bundling of NCE energy efficiency measures

PGE adopted a similar process as the Northwest Power and Conservation Council and aggregated measures into discrete bundles (or 'bins') based on the measures' levelized costs. Within these five bins the NCE energy efficiency measures are organized based on the rank of the measure's levelized cost. The bin ranges are generated by creating megawatt-average thresholds across the cumulative megawatt-average of total NCE potential. In the 2023 CEP/IRP, the bin ranges were established by prioritizing bins that contained at least 10 megawatt-average per bin. In the 2023 CEP/IRP update, the bin shapes prioritize aggregation according to average fixed cost. In portfolio analysis, the analysis of any given bin will assess the next set of potential energy efficiency measures that share similar cost structures rather than assessing the next 10 megawatt-average of the cumulative NCE potential.

From these bin shapes, PGE is able to calculate the maximum potential NCE energy efficiency savings by year. Updated bin shapes are summarized in **Table 24**. PGE then calculates costs,

capacity factors, ELCCs and energy values for each bin shape with which to characterize the NCE energy efficiency as resources available for selection in portfolio analysis.

Table 24. Cumulative NCE EE potential by Bin (MWa) through 2030

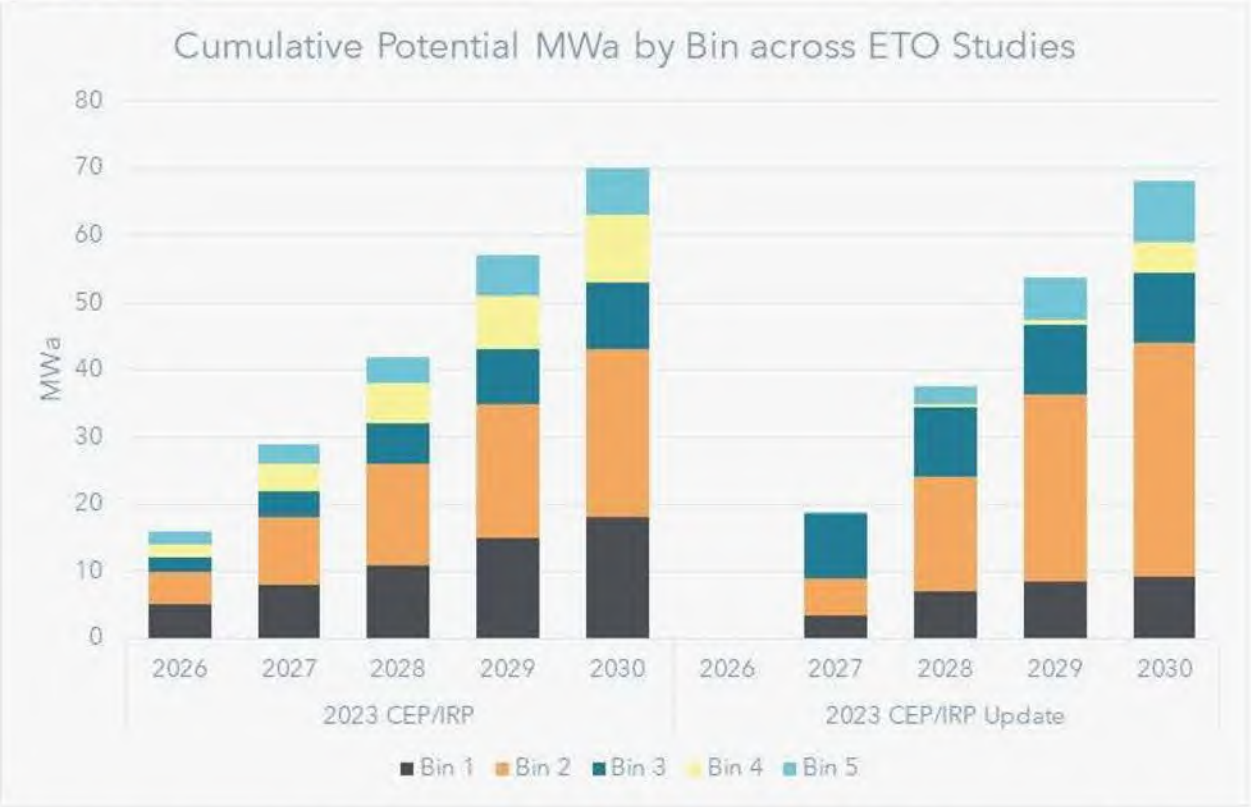
Year	Bin 1	Bin 2	Bin 3	Bin 4	Bin 5
2026	0.0	0.0	0.0	0.0	0.0
2027	3.5	5.5	9.5	0.1	0.2
2028	7.0	17.0	10.4	0.6	2.7
2029	8.6	27.8	10.4	0.7	6.2
2030	9.1	34.9	10.4	4.6	9.1

5.3.4 Comparing NCE energy efficiency in 2023 CEP/IRP to the 2023 CEP/IRP Update

The total cumulative megawatt-average of NCE energy efficiency expected by 2030 changes little between the 2023 CEP/IRP and the 2023 CEP/IRP Update, falling from 70 megawatt-average to 68.1 megawatt-average across all five bins, as summarized in **Figure 52**. The bin sizes differ between filings as the changes in the fixed costs for each NCE energy efficiency measure led to resorting across the five bins.[121]

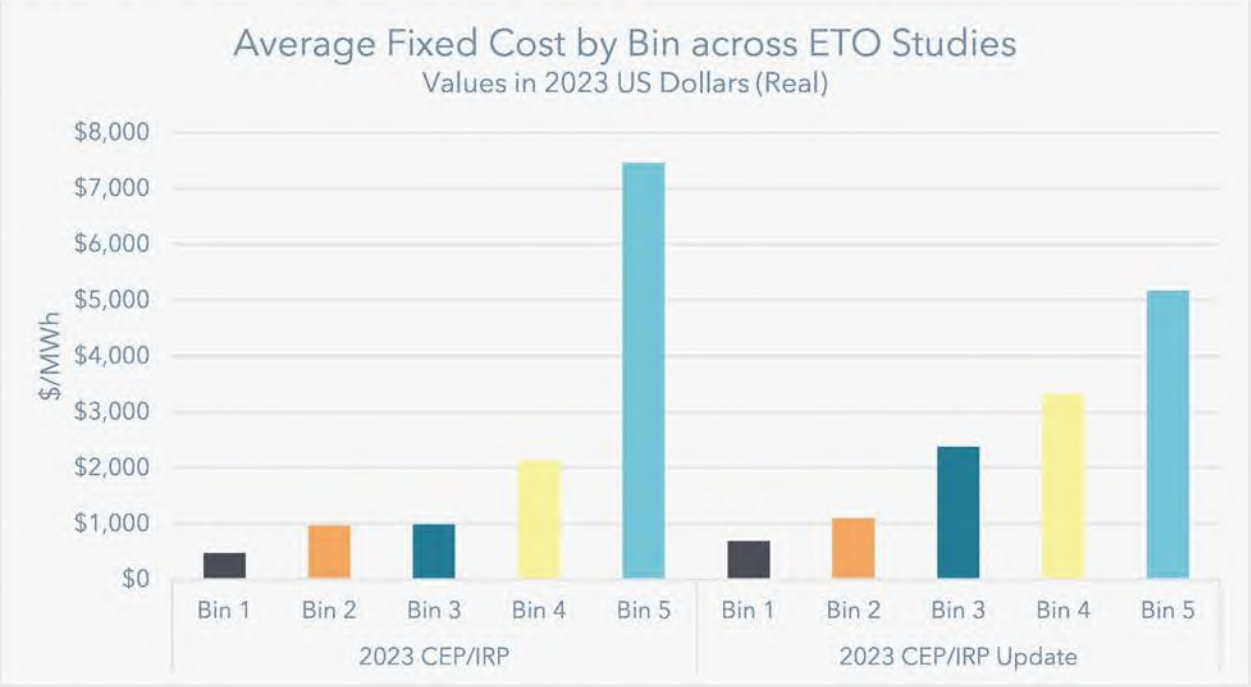
[121] In the 2023 CEP/IRP PGE was able to create roughly 10 MWa bins by aggregating programs with similar levelized costs. In the CEP/IRP Update PGE prioritized keeping bins of similar costs, which resulted in differences in MWa bin size.

Figure 52. Comparison of the Potential MWa by Bin between the 2023 CEP/IRP and the 2023 CEP/IRP Update



There is an increase in the average fixed costs for all bins, except Bin 5, as average levelized costs increased 37.2 percent over all measures, as depicted in **Figure 53**. The increases in average fixed costs are due to rising costs of EE equipment driven by inflation, changes in supply chain, post-COVID effects, and increased avoided costs, making measures that were on the margin now cost-effective. This removes lower cost measures from the list of NCE measures.

Figure 53. Comparison of the Average Fixed Cost by Bin between the 2023 CEP/IRP and the 2023 CEP/IRP Update expressed in real $ (2023)



5.3.5 Energy efficiency program and policy

This section provides an update on near-term commitments to address costs and implementation challenges present in the accelerated procurement of the Energy Efficiency identified in the 2023 CEP/IRP.[122] Those commitments include:

- Supporting Energy Trust of Oregon's development of guiding principles to actively consider utility rate impacts,
- Supporting Energy Trust of Oregon's creation of a mechanism to set targets for outside funding and requirements for regular reporting,
- Supporting Energy Trust of Oregon's formalization of the divisions of labor and funding allocations established between Energy Trust of Oregon and other entities,
- Exploring the co-deployment of flexible load and EE programs with near-term focus on how these programs can help customers participating in PGE's Income Qualified Bill Discount, and
- Continued collaboration on program demonstration in the PGE testbed and measure development that includes complementary funding.

This Update represents an articulation of PGE's understanding of the feasibility of new cost recovery mechanisms, pathways for co-deployment informed by stakeholder feedback and the

[122] OPUC. Acknowledgement of 2023 Integrated Resource Plan and Clean Energy Plan. Docket No. LC 80, December 14, 2023, Page 9. Retrieved from https://edocs.puc.state.or.us/efdocs/HAU/lc80hau325590032.pdf.

stage of readiness achieved by Energy Trust of Oregon. Some dependencies that may impact the progress on commitments made, and perhaps the Need Futures presented, include the revision to the Energy Trust of Oregon Grant Agreement, the timing and magnitude of public sector funding, changes made to avoided cost methodology on UM 1893, and Energy Trust's ability to engage and formalize roles with other public sector entities.

5.3.5.1 Utility rate impacts

Energy Trust has recently increased its focus on leveraging customer funding paid through rates with other, complementary funding sources to enable deeper retrofits, increase savings, reach more customers, and deliver overall greater value. PGE worked with Energy Trust in 2024 to refine and articulate principles for complementary funding.

Energy Trust will align its investments with Oregon's decarbonization policies by following guidance from the OPUC and supporting customer fuel choices with high-efficiency equipment incentives. They will address fuel-switch constraints and ensure efficient use of resources to advance state policy objectives. Additionally, Energy Trust may administer programs promoting clean air and decarbonization with separate funding if it aligns with their vision and purpose.

Defining leveraging, braiding and co-funding

The term "leveraging" is used loosely to cover a broad range of complementary funding strategies that bring additional, public-sector funds to support Energy Trust projects, programs, and activities. "Braiding," "co-funding," "layering" or "stacking" funding streams is a process for using multiple sources of funding to support a common program or project that results in energy savings or generation.

This complementary funding is expected to contribute through the following efforts:

- Enable: Braiding dollars for deferred maintenance overcomes a barrier to participation.
- Amplify: Energy Trust delivery infrastructure and multi-utility funding model produces economies of scale by an order of magnitude ($1 ratepayer: $10 taxpayer).
- Offset: Braiding dollars improves cost-effectiveness by reducing the incremental measure cost.

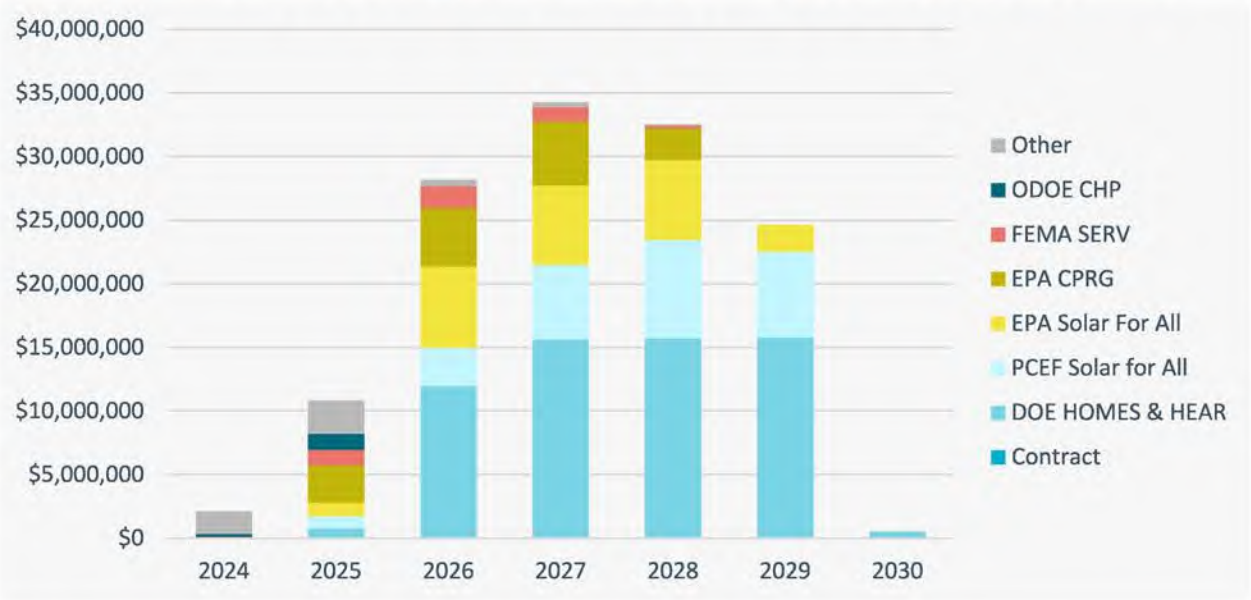
Guiding principles for leveraging funds

Energy Trust has stated that it will prioritize leveraged funding to increase energy savings and generation, improve equitable access to services, stretch customer dollars, and fill unmet customer needs. They also committed to minimizing program confusion, strengthening stakeholder relationships, ensuring continuous customer support, and enhancing contractor effectiveness. Leveraged funding examples include co-funding heat pump installations, provided it results in greater benefits for customers.

5.3.5.2 ETO funding allocation

In 2025, Energy Trust will be developing a complementary funding strategy as a component of the 2026-2030 multiyear plan. This component of the multi-year plan will outline strategies to leverage other funding in support of multiyear program strategies to achieve energy targets. Current estimates provided by ETO, across all utility funders not just PGE, are shown in **Figure 54**, though exact timing and amounts may be subject to change.

Figure 54. Estimated Energy Trust Complementary Funding Revenue by Year, Contract



PGE customers benefit from the leveraging of taxpayer dollars. Given that public sector grants and rebates fund the same end-use improvements it is important to establish an understanding of the roles and responsibilities across funding administrators and implementers so as not to duplicate efforts. This sorting and defining of roles is currently happening at the funding opportunity or contract level for Energy Trust. For example, for EPA Solar For All, this is described in the role of partners within that agreement.

5.3.5.3 Co-Deployment of Flexible Load and EE programs

Action Planning with Energy Trust of Oregon

As a result of legislative direction in HB 3141 (2021), codified as ORS 757.746(e), Energy Trust of Oregon was required to, "with public utilities, jointly develop public utility specific budgets, action plans and agreements that detail the entity's public utility-specific action plan (USAP), resources, including coordinated activities that require joint investment and deployment." Also, per the legislation, "Each action plan must reflect stakeholder feedback gathered through a public process managed by the entity and the relevant public utility as overseen by the commission." This statutory direction required modification to Energy Trust's current budget development process, with more utility-specific coordination.

In June of 2022, following a series of work sessions with OPUC, Energy Trust, utility funders and customer advocates, a Budget Process Coordination and Action Plan Memorandum (the "HB 3141 Budget Coordination Memo") was formed. This memorandum represented a joint planning framework that articulated stepwise activities to support annual budget and utility-specific action planning.

Building on this plan development process the Energy Trust and PGE propose evolving from a two-year cycle to a multi-year (2026-2030) time horizon and from an activity-based plan to an outcomes-based co-deployment framework. Doing so affords the two organizations the opportunity to better maximize value for shared customers, accelerate procurement as determined in the PGE Integrated Resource Plan in compliance with HB 2021, as well as align based on organizational and program readiness.

Co-Deployment

Co-deployment with the Energy Trust encompasses a shared strategy, with common marketing, outreach, and messaging, to efficiently deliver complementary energy services to shared customers. Through co-deployment of complementary services, customers benefit from behind-the-scenes coordination with streamlined participation and total delivery cost reduction for all customers. To start, co-deployment will include targeting priority high energy burdened customers with services that lead to meaningful bill reduction and advance the shared objective of reducing energy burden. The timing of this effort is aligned with implementation of HB 2475 through the OPUC docket UM 2211, with the goal of reducing energy burden and the anticipated availability of public sector funding. Co-deployed services will initially consist of existing, feasible offerings provided by each organization today. Over time, additional services and deployment forms or pathways will be added to the framework as each organization is ready to bring in more services to market. The framework will evolve to focus on different configurations of candidate screening and more targeted delivery.

Co-deployment may take a variety of forms and pathways:

- Community outreach: Shared program marketing collateral and tabling events together
- Co-funding: A methodological approach in which PGE provides complementary funding for flex value (e.g., residential thermostats)
- Bill reduction: Referral of IQBD customers to increase EE program participation (also provides flex potential for future co-funding opportunities)
- Solar+ storage: Aligning PGE smart battery roadmap with the U.S. Environmental Protection Agency Greenhouse Gas Reduction Fund Solar for All grant funding timing
- Pilot to program: Ensuring that tested collaboration yields a hand-off to product and measure development.

5.4 SSR resource

A new proxy supply-side resource was added to represent the range of small-scale renewable (SSR) resources that may be available to help PGE meet Oregon's ten percent small-scale

renewable requirement. The inclusion of a SSR resource allows the requirement that starts in 2030 to be accounted for in portfolio analysis.

The ten percent requirement uses only one metric (i.e., 20 MW or less in size) and does not incorporate community benefits.[123] The purpose of the SSR proxy resource is strictly to analyze compliance with the ten percent requirement; consequently PGE chose to design the resource to represent projects on the upper end of the 20 MW size limit, which are less costly than smaller community-scale projects. Smaller-scale projects are already considered in portfolio analysis through the lens of CBREs.

Due to limited suitable locations within PGE's service territory to site a 20 MW renewable energy facility, the resource is assumed to be off-system. The resource cost and performance parameters of the SSR resource are based on the Christmas Valley solar proxy resource. The performance characteristics match those of the Christmas Valley solar resource. This means having the same generation profile and resulting capacity factors and energy value. The cost characteristics are scaled to account for the fact that smaller projects benefit less from economies of scale than larger projects and therefore can be expected to be more costly on a per-unit basis. In order to account for this size-cost dynamic, the $/kW fixed costs of the SSR resource are inflated by eight percent above the fixed costs of the Christmas Valley solar resource, the fixed costs of which are based on an assumed 100 MW DC project size. Analysis in Berkeley Lab's "2024 Utility-Scale Solar, 2024 Edition" report is used to estimate a cost premium associated with smaller-scale resources. In the report, projects between 5-20 MW DC were found to have a weighted mean capex cost of $1.28/W, while projects between 50-100 MW DC had eight percent lower capex costs, with a weighted mean of $1.18/W.[124]

5.5 Community benefits indicators (CBIs)

PGE has taken steps to advance the integration of community benefits indicators (CBIs) into resource planning processes, consistent with regulatory directives and community stakeholder priorities. This chapter provides an update on the development, refinement, and application of CBIs since the 2023 CEP/IRP. As guided by OPUC Order 22-390 and stakeholder input,[125] PGE has expanded its CBI framework to encompass measurable and impactful metrics across resilience, health and community well-being, environmental impacts, energy equity, and economic impacts. This update aims to share key developments, preliminary findings, and the roadmap for future efforts.

For example, PGE has long supported customer-sited resources connecting to the power grid. **Figure 55** shows rooftop solar installations have grown roughly four-fold in the past decade.

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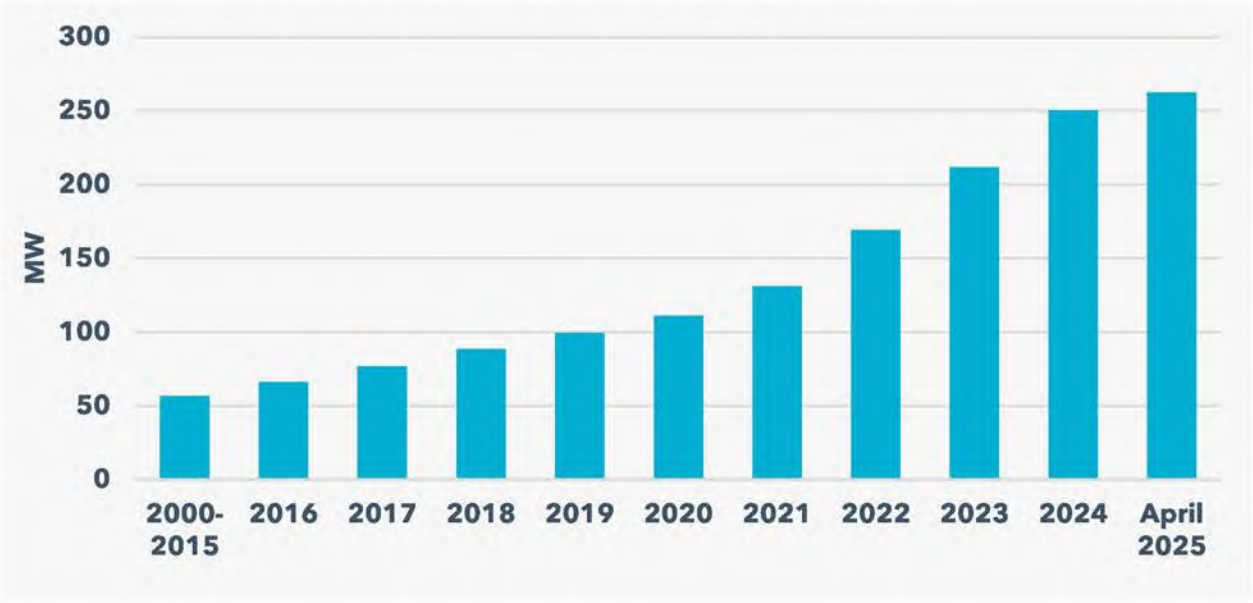
[123] While SSR resources can be CBRE's, they are not required to provide the community benefits that distinguish CBRE's from other small-scale resources. The SSR proxy resource therefore does not include any assumption of provision of community benefits beyond what would be provided by larger utility-scale resources.
[124] Berkeley Lab's "2024 Utility-Scale Solar, 2024 Edition" report can be found at http://utilityscalesolar.lbl.gov.
[125] This order, along with valuable stakeholder input, has guided PGE's approach to Community benefits indicators Oregon Public Utility Commission. (2022). Order No. 22-390 in Docket No. LC 73. Retrieved from https://apps.puc.state.or.us/orders/2022ords/22-390.pdf.

Community-based renewable energy is just a part of what PGE will quantify and track toward CBIs.

Figure 55. Cumulative Installed Rooftop Solar PV Capacity (MW)



5.5.1 Background and regulatory framework

OPUC Order 22-390 provided guidance on CBIs and their application to CEP/IRP analysis and established five CBI topic areas that must be included: health and community well-being; resilience; environmental impacts; energy equity; and economic impacts.[126] The Order also required that these topics should include at least one metric of each of three CBI categories. In 2023, PGE filed its first CEP as part of the IRP, including a set of CBIs responsive to these three CBI categories:

1. **Portfolio CBIs (pCBI)**: the CEP included a proxy value for all CBRE, set at 1 MW of CBRE equal to 1 unit of community benefit, reflecting an unspecified set of benefits associated with a hypothetical CBRE
2. **Resource CBIs (rCBI)**: PGE utilized a ten percent adder to reduce the levelized cost of CBRE projects, reflecting an approximation of the associated community benefit value of CBREs within the resource portfolio comparison process
3. **Informational CBIs (iCBI):** PGE identified a set of six iCBI and associated metrics, based on community engagement efforts and stakeholder feedback

In April 2024, OPUC issued Order 24-096, which identified the following required actions:

[126] Oregon Public Utility Commission. (2022). In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, 2019 Integrated Resource Plan (Order No. 22-390). Retrieved from https://apps.puc.state.or.us/orders/2022ords/22-390.pdf

"PGE must demonstrate development of CBIs to assist in our understanding tradeoffs between cost, risk, and community benefit, and when evaluating procurement decisions.

"PGE must develop a set of informational-only metrics by its next CEP/IRP or provide a detailed explanation of barriers, constraints, and a proposal for resolution." [127]

5.5.2 Advancing CBI methodologies and integrating to the IRP

5.5.2.1 Updated CBI approach

In 2024, PGE engaged Cadeo (now Resource Innovations) to conduct research into CBIs. Based on this research and stakeholder feedback, PGE refined its approach to CBI as follows:

1. Expanded CBI List: PGE incorporated a list of 30 CBIs that was developed by Cadeo, characterized by their applicability to specific resources, monetizable value, and alignment with OPUC categories (see **Figure 56**). For more detail on how Cadeo developed this list, please see **Appendix G**.
2. Valuation Methods: Cadeo's research into monetizable CBIs has developed a method to include five pCBI categories to align and comply with OPUC requirements. For rCBIs, Cadeo reviewed several studies which they then used to quantify percentage adjustments which would reduce the levelized cost of capacity for several specific resource bundles.
3. Stakeholder Collaboration: PGE Engagement with the IRP Roundtable, OPUC Staff, and the Community Benefits and Impacts Advisory Group (CBIAG) has informed revisions to CBI metrics and methodologies. The CBIAG provided valuable feedback on the CBI framework, suggesting improvements and identifying areas for future exploration. Affordability emerged as a key concern, particularly regarding the impact of investment costs on customer rates, especially for those with higher energy burdens.
4. Integration Strategies: PGE research proposed four distinct approaches to incorporate CBIs into IRP modeling, ranging from proxy indicators to direct cost adjustments.

[127] Oregon Public Utility Commission. (2023). Docket No. LC 80, Order 240-096: PORTLAND GENERAL ELECTRIC COMPANY 2023 Integrated Resource Plan. Retrieved from https://apps.puc.state.or.us/edockets/DocketNoLayout.asp?DocketID=23636

Figure 56. List of CBIs by Category

CBI CATEGORY ◯ Portfolio CBIs ◯ Resource CBIs ◯ Informational CBIs

1	Economic development impact	7	Ancillary services	13	Increased availability of electricity storage in Tribal and non-Tribal communities	19	Increased satisfaction and pride	25	Improved grid resiliency
2	Increased access to jobs	8	Reduction in GHG Emissions	14	Increased number of clean energy generation that powers Tribal communities	20	Improved comfort in home	26	Increased resilience/reliability in targeted communities
3	Increased property or asset values	9	Improved access to reliable clean energy	15	Improve efficiency and housing stock in utility service territory, including LI housing	21	Improved public health outcomes	27	Reduction in recovery time and increase in survivability from outages
4	Economic well-being	10	Improved participation in clean energy programs by EJ communities	16	Increased energy affordability/reduction in energy burden for EJ communities	22	Improved community health outcomes in targeted communities	28	Reduction in frequency and duration of black/brownouts in target communities
5	Increased productivity	11	Increased awareness of utility programs for EJ communities	17	Reduced arrearages/late payments	23	Reduced local emissions (pollution burden, pollution exposure)	29	Reduced risk to targeted communities from outages
6	Energy Security	12	Meaningful bilateral engagement between utilities and tribes on siting	18	Reduced residential disconnections and collections	24	Improved household health and safety outcomes in targeted communities	30	Increased neighborhood safety from natural disasters

5.5.2.2 Integrating CBIs into IRP modeling

Following CBI discussions and direction from UM 2225 and LC 80, PGE has utilized the same structured pathways to integrate CBIs into IRP processes:

Resource CBIs highlight the localized benefits of individual projects:

- rCBIs can be used to adjust levelized costs of specific resources. For instance, the economic and health benefits of solar panels and energy efficiency measures are quantified and incorporated into resource cost comparisons.
- These adjustments could be used to influence the cost-minimization portfolio analysis towards the selection of resources that maximize community benefits.

Portfolio CBIs reflect the cumulative benefits of resource portfolios, with emphasis on economic, environmental, and equity impacts.

- pCBIs are determined by the quantities of resources selected in portfolio analysis.
- Portfolios with higher pCBI values could be identified as higher performing in portfolio analysis (based on their broader community benefits).

Informational CBIs

- iCBIs may be used as tracking tools to monitor long-term impacts, such as the percentage of low-income households benefiting from clean energy programs, quality job creation, and increased resiliency within Tribal and energy-burdened communities.

In the initial use of Resource CBIs, a direct adjustment was applied to the levelized cost of specific energy resources to account for measurable participant benefits. While research identified a set of eight core benefit categories with the potential for monetization, only those substantiated by secondary data sources were included: property value increases and comfort improvements. Due to limited primary research on benefit valuation for specific resource types within PGE jurisdiction, this analysis relied on secondary sources and adapted benefit metrics for IRP application. PGE caveats that these benefits accrue to the participant not directly to the community (and therefore supports further refinement of this framework through planning and acquisition efforts). The assumption underlying the application of these benefits is that these participant benefits, when aggregated in a local setting, result in a community benefit. This initial assessment and application of these first rCBIs were integrated into IRP evaluations as percentage reductions to resource costs.

Examples of **rCBI Application** include the reduction of resources costs to account for:

- **Community-based renewable energy (CBRE) Solar** if qualified by providing tangible and resilience benefits to community is based on a 6.8 percent increase in property values, reflecting benefits tied to behind-the-meter installations for residential customers.
- **Energy efficiency (EE)**, to reflect monetization of comfort benefits at $62 per project annually for low-income households and $42 for non-low-income households.
- **Curtailment programs (Battery Storage)** based on a 2.3 percent increase in property values for residential batteries enrolled in curtailable Summer/Winter programs.

Table 25 summarizes selected rCBI applications.

Table 25. Assumed rCBI Applications

CBI	Resource Category	% Reduction to Levelized Cost	CBI Benefit Metric	Source	IRP Application Assumptions
Property Value	CBRE Solar	**269%**	6.8% increase in property value	Zillow 2024	Assumes 5 kW residential solar install; applicable to behind the meter projects; dependent on ownership structure (i.e., assumes value occurring at time of sale for home/property owner)
Property Value	Demand Response	**64%**	2.3% increase in property value	Zillow 2024	Assumes applicability for 5kW residential battery, assumes behind the meter installation
Property Value	EE	**45%**	0.5% increase in property	LBNL 2022	Applicable for home performance projects (e.g., HPwES, whole-house weatherization); reflecting Residential study.
Comfort (Shell)	EE	**10.6% LI; 7.2% non-LI**	$62/project (LI); $42/project (non-LI)	EmPOWER Maryland (2023)	Applicable for projects with shell measures (insulation, air sealing); benefit accrue annually over measure lifetime

CBI	Resource Category	% Reduction to Levelized Cost	CBI Benefit Metric	Source	IRP Application Assumptions
Comfort (HVAC)	EE	**5%**	Average of $30/project (3%) and $100/project (7%)	MA Residential NEI Study (2023); EmPOWER Maryland (2023)	Applicable for HVAC replacements using heat pumps; benefits accrue annually over measure lifetime; assuming 2000 kWh annually, 18-year EUL, and project cost of $15,000.

The rCBI benefits PGE was able to identify and quantify required two key conditions: (1) access to existing research with adaptable, quantified benefits; and (2) available data across all applicable resources for a given benefit. This consistency requirement is key for maintaining balanced resource comparisons, as including monetized benefits with the levelized costs for only some eligible resources would create an uneven evaluation framework. The approach prioritized consistency, meaning CBIs through the rCBI pathway were only applied when complete data existed across all applicable resources. Otherwise, associated benefits are considered within the pCBI approach.

Portfolio CBIs: Proxy-based Benefits

Portfolio CBIs represent those benefits which are more challenging to quantify or monetize, or that may have insufficient available data for all eligible resources (and thus present an imbalance if included for some but not all resources). For this update PGE attempted to assign these benefits to resource bundles in line with the economic, equity, health, resilience, and environmental categories laid out in OPUC guidance. PGE applied pCBIs as proxy values at the backend of the IRP modeling sequence after resource bundles were established, to characterize and identify bundles that likely accrue specific CBI benefits. PGE then considers these CBIs as part of the scorecard approach for portfolio selection.

Examples of **pCBI Application**:

- **Economic Impacts**: Included economic development, increased access to jobs, economic well-being, increased property value, and increased productivity. Economic impact benefits are identified for a wider range of resources, not limited to demand response and CBREs. This includes supply-side resources as potential economic development and job creation opportunities exist across various resource categories.
- **Energy Equity**: Benefits such as improved affordability and reduced arrearages were assigned to CBRE, energy efficiency (EE), and demand response (DR) (specifically time-of-use rates), applicable to resources targeting disadvantaged communities and those with highest likelihood of yielding bill impacts.
- **Health and Well-being**: Proxy values for improved indoor air quality and household safety were applied to weatherization and HVAC measures.
- **Environmental Impacts**: Emissions reductions were reflected across CBRE and demand-side

resources to account for their role in mitigating climate change. In the development of the IRP, the availability of pCBIs remains limited for many resource options under consideration. While pCBIs have been identified for certain distributed energy resources, such as community-based renewables and energy efficiency programs–where benefits like energy equity, local economic development, and resilience can be reasonably quantified–many supply-side resources lack studies or assessments that would inform the application of pCBI benefit.

This is primarily due to the complexity of attributing broad community benefits to large-scale generation and transmission assets, as well as the absence of standardized methodologies for quantifying their indirect social and environmental impacts.[128] **Table 26** highlights how the five topic areas for pCBIs were mapped to resource bundles, this table excludes resources such as out-of-state wind and others that do not have associated pCBIs.

Table 26. pCBI Mapping

Resource Bundle	Economic Impacts	Energy Equity	Health/ Well-being	Resilience	Environmental Impacts
CBRE Solar	✓	✓		✓	✓
Energy Efficiency	✓	✓	✓	✓	✓
Demand Response	✓	✓		✓	✓
CBRE Microgrids	✓	✓	✓	✓	✓
Battery	✓	✓			
CBRE Hydro	✓	✓		✓	✓
Gas Turbine	✓				
CV Hybrid	✓				
Wind - PGE territory	✓				
Solar - PGE territory	✓				

There are detailed applicability requirements for all CBIs, therefore resource-specific applicability must be carefully considered. These requirements relate to factors including measure characteristics, program design, geographic targeting, and baseline conditions. For

[128] These results are consistent with PGE's statements in UM 2225 about the inability to create useful and rigorous estimates of community benefits indicators to be applied in IRP analysis.

example, CBIs unlocked through energy efficiency often relate to specific measures, such as weatherization or HVAC improvements. When IRP resource bundles include various end-uses and technologies, these CBIs may only apply to a subset of the energy savings. Additionally, some CBIs focused on equity outcomes require geographic considerations, such as savings occurring within locations designated as environmental justice or tribal communities. Other CBIs aimed at achieving customer-level economic impacts related to energy affordability will be contingent upon resources that can achieve higher levels of bill savings.

5.5.3 Challenges and next steps

PGE faces several challenges integrating CBIs into its IRP process. One significant issue is the limited availability of jurisdiction-specific studies to substantiate the valuation for certain CBIs. Local conditions such as weather, the characteristics of the residence, customer awareness, power generation mix and location, distribution grid infrastructure status, and more can influence the valuation of different types of benefits. PGE has identified a need for further primary research to reflect these local conditions and policy goals and looks forward to engaging with stakeholders on the method, scope, and objectives of this research. The company is conducting a CBRE Request for Offer (RFO) through November 2025, which serves as a valuable tool for market research on project costs and CBIs. The insights gained from this process, including evaluations by CBIAG and engagement with OPUC Staff, should be incorporated into future resource planning updates to demonstrate PGE's commitment to understanding and valuing community benefits.

Another challenge lies in the limitations of proxy metrics, which require a balance between precision and usability. These metrics must be refined to ensure they provide meaningful insights while remaining practical for use in resource planning.

PGE has identified the need for further research to fully capture the benefits of Distributed Energy Resources (DERs), particularly for those DR resources not associated with EE. This may include considering the development of a cost-test model that could potentially incorporate identified community benefits. The process may involve examining recent research methodologies for quantifying benefits. New York State Energy Research and Development Authority's (NYSERDA) Community Adder program was reviewed for concept insights, finding additional incentives for community solar projects benefiting disadvantaged communities.[129] In consideration of the principles outlined in HB 2021, PGE aims to evaluate potential strategies for improving clean energy accessibility, assess projects that may provide benefits to disadvantaged communities, and pursue clean energy and equity objectives, while maintaining a focus on meeting load requirements and striving for cost-effective solutions for customers.[130]

[129] NYSERDA. *Community Adder* webpage. Retrieved from https://www.nyserda.ny.gov/All-Programs/NY-Sun/Contractors/Dashboards-and-incentives/Community-Adder.
[130] Oregon House Bill 2021, Section 1(3)(a), 2021 Regular Session. https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2021/Enrolled.

5.5.4 Conclusion

Integration of CBIs provides an opportunity for PGE to extend resource planning to include the values and priorities of the communities PGE serves. CBIs offer a means by which to quantify benefits such as resilience, equity, environmental impact, public health, and economic development.

The challenges identified–including data gaps, proxy metric limitations, and diverse stakeholder priorities–highlight the need for continued research, collaboration, and refinement. As detailed earlier in the section, PGE believes continued stakeholder engagement, localized data development, and the adoption of advanced methodologies are necessary to overcome these challenges and enhance the impact of CBIs.

5.6 Long lead-time resources

This section provides an updated summary of Chapter 8.5 of the 2023 CEP/IRP regarding potential future resource options that PGE considered, including new generation and transmission expansion to other regions.

5.6.1 Post-2030 resource options

In 2024, in response to docket LC 80, PGE enacted a "Request for Information" (RFI), reaching out to WECC market participants to better understand post-2030 regional resource availability.[131] Using a comprehensive questionnaire distributed amongst a variety of developer communities and trade organizations, PGE gathered information on producers across key production regions in the WECC market and included a public/stakeholder workshop on these findings in late 2024.[132] That work has granted some insights that are relevant to post-2030 resourcing and is referenced in this section of the Update.

5.6.2 Hydrogen and ammonia

Included in the Inflation Reduction Act is a new 45V Clean Hydrogen Production Tax Credit (10-year duration). The tax credit provides up to $3.00/kg of hydrogen produced based on the emission intensity of the energy used to produce hydrogen. The law lays out a series of qualifying conditions in order to receive the credit, including a calculation of the lifecycle GHG emissions of the electricity, the age of the producing asset, and other considerations. Section 45V may yet serve as an additional incentive to the implementation of green hydrogen applications.

The federal government established a multi-billion-dollar grant for green hydrogen hub development nationally, with Oregon's Pacific Northwester Hydrogen Association receiving up

[131] Staff Report, recommendation #2, filed December 14, 2023, https://edocs.puc.state.or.us/efdocs/HAU/lc80hau325590032.pdf.
[132] PGE RFI Key Insights presentation, December 2024, https://assets.ctfassets.net/416ywc1laqmd/2GF5BwVt9cR1MXtEpn6fli/e719ec6879183abd984928db360fe410/RFI_slides_jdg_web_1197.pdf.

to $1 billion for four DOE-defined development phases spanning nine years. PGE has participated in this consortium to identify an opportunity to make this additional incentive available for customers, though there is currently some uncertainty of funding under the new Trump Administration.

5.6.3 Nuclear

In Oregon, Measure 7 prohibits the construction of a new nuclear power plant in the state without a federal long-term nuclear waste repository and a statewide popular vote. However, there is growing national interest in nuclear power as a non-emitting resource with active projects appearing in neighboring states.

In their 2021 IRP, PacifiCorp identified a sodium cooled fast reactor nuclear power plant with molten salt storage as a demonstration of the commercialization of this new, potentially safer, nuclear technology. Construction on the plant began in 2024, in conjunction with TerraPower, and incorporates a storage unit that will allow the production of 500 MW for short durations, with an anticipated online date in 2030. In PacifiCorp's 2023 CEP/IRP, the company announced two other nuclear power plants to be built in Utah, on the sites of soon-to-be-retired coal plants, both to be natrium plants producing 500 MW each. However, PacifiCorp communicated its intention to pull back on these two new plants in an IRP revision in mid-2024.

In Washington, small modular reactor (SMR) projects have also moved forward as Energy Northwest has partnered with X-energy to design a program of 12 small plants, each producing 80 MW. As of Q4 2024, Amazon Web Services agreed to partner on four advanced SMRs, generating 320 MW on the Columbia River, with the plants expected to enter service in the early 2030s. Once partnerships and funding are found for the other eight SMRs, 640 MW of nuclear power may come online in Washington.

It remains to be seen if next generation nuclear technology can lower the cost, safety, and political hurdles faced by traditional nuclear power.

5.6.4 Geothermal

PGE's 2024 RFI gained information on few geothermal projects developing inside Oregon. The projects utilize experimental technology and are expected to enter service in 2030-onward. The projects together will generate approximately 75 MW of continuous non-carbon-emitting power, a sizeable addition to Oregon's current geothermal operations, but a very small fraction of the total potential geothermal energy available in the State.

Future improvements in drilling technologies will result in reduced development time and costs. Developments in EGS stimulation technology and higher success rates will also reduce costs and development timelines.

5.6.5 Post-2030 wind/solar generation

PGE's 2024 RFI reflected a potential 6 GW of wind and solar projects at various stages of development, to come online between 2030-2034. Of these 6 GW, ~2,7 GW are being produced

in Oregon, primarily in the form of wind projects with varying degrees of feasibility. With another 3.1 GW in neighboring states, also mostly in the form of wind projects (although some 300 MW of Nevada stand-alone solar are also coming online).

5.6.6 Long-term hybrid resources

The 2024 PGE RFI produced information about future hybrid projects coming online in 2030 and after. According to the RFI, some 4 GW of hybrid projects are to come online between 2032-2034: 2.5 GW in Oregon, incorporating both wind and solar resources; and the other 1.5 GW in neighboring markets. In particular, 1 GW of solar + storage units coming online in Nevada, access to which could be improved through transmission expansions options discussed in **Chapter 4**.

5.6.7 Long-duration storage

Long Duration Energy Storage (LDES) is defined as any electricity storage with greater than six hours of duration. In early 2025, the U.S. Department of Energy's (DOE) Office of Electricity announced a Notice of Funding Opportunity for up to $8 million seeking to accelerate energy storage manufacturing through pre-production design innovations to ultimately scale this technology faster to meet the nation's growing energy storage needs.

Currently lithium-ion batteries are the most common storage options on the market, but other chemical storage options include flow batteries. Longer duration batteries may soon be more widely available.

Another potential technology for longer-duration storage relies on pumped air/iron-air storage, wherein energy expended in oxidation and de-oxidation constitutes a storage technology. Organized in large battery packs, this technology permits 100+ hours of storage in testing environments and is demonstrably cost-effective when compared to lithium-ion battery storage technology. Form Energy, a company founded in 2017, is pioneering this technology across the United States.[133] For example, Great River Energy, a Minnesota Utility, is working to develop a multiday iron air battery.

As more variable energy resources are expected to arrive on both the PGE system and the greater Western Interconnection, there may be increased opportunities to use storage to shift energy from oversupply hours to hours of greater need and value.

[133] https://formenergy.com/form-energy-secures-405m-in-series-f-financing-to-expand-iron-air-battery-business-and-operations/.

Chapter 6. Resource plan

This report updates PGE's comprehensive and robust 2023 CEP/IRP portfolio analysis. The analysis presented in this chapter incorporates updates to key inputs and advancements to PGE's modeling capabilities. The portfolio analysis in the 2023 CEP/IRP identified a Preferred Portfolio based on the insights gained from the evaluation of transmission need, GHG glidepaths, the role for additional EE and DERs, CBRE's, emerging technologies, and optimization assumptions. Portfolio analysis in this Update carries forward those insights where applicable, while updating key inputs and incorporating modeling advancements to determine a new Preferred Portfolio.

This portfolio analysis incorporates PGE's most recently available forecasts of energy and capacity needs and updated resource cost information. This analysis incorporates updated characterization of the state of the existing transmission system and a comprehensive set of options to increase transmission access through upgrades or expansion. PGE also incorporated modeling advancements to GHG emissions accounting, granularity of energy accounting, and CBI reporting.

The updated modeling inputs and methods were used to inform the creation of a new Preferred Portfolio, which is described in detail in **Section 6.2 Preferred Portfolio**. The Preferred Portfolio is analyzed from multiple angles to consider annual cost impacts, resource adequacy, hourly emissions reporting, and SSR compliance. Multiple sensitivities are conducted on the Preferred Portfolio, exploring key topics of interest regarding large industrial customer growth, resource adequacy planning assumptions, the availability of federal tax credits, and the availability of non-emitting market purchases for hourly emission accounting.

Key Highlights

- The updated Preferred Portfolio demonstrates a least-cost, least-risk approach to meeting resource adequacy needs while decarbonizing in accordance with HB 2021, including 1362 MW of wind, 1089 MW of solar, 1750 MW of storage, 83 MW of NCE EE and DERs, and 155 MW of community-based renewable energy (CBRE) resources by 2030.
- Hourly emissions analysis confirms the Preferred Portfolio can comply with HB 2021 emissions limits in 2030, with thermal generation concentrated in winter months when non-emitting energy is scarce.
- Resource adequacy testing reveals winter adequacy challenges requiring substantial storage resources, suggesting the need to identify different capacity resources better suited to meet ongoing winter capacity needs.

Developments Since 2023 IRP

The 2023 IRP Update incorporates significant methodology improvements including: monthly energy accounting (versus annual in 2023 IRP), updated resource cost information, comprehensive transmission upgrade options, enhanced GHG emissions

accounting, and greater CBI reporting granularity. An expansive set of portfolio sensitivities were developed to explore key planning questions that have increased in prominence since the filing of the 2023 CEP/IRP.

Strategic Implications

The analysis reveals the critical importance of transmission options for meeting system needs, with all seven transmission options being added between 2032-2038, unlocking 6927 MW of off-system renewables. Winter adequacy challenges are more precisely identified, showing short-duration storage has limited effectiveness in winter capacity needs (seven percent ELCC) compared to summer (53 percent ELCC), highlighting the need for alternative capacity resources with greater energy storage capability or on-demand production.

Staff Recommendations Incorporated

The Update directly addresses Order 24-096 directives through updates to portfolio analysis. PGE addresses Staff Recommendation #3 by conducting hourly production cost simulation of the Preferred Portfolio to separately track hourly purchases and sales. Resulting GHG emissions impacts better demonstrates HB 2021 compliance and reveals key planning insights while allowing PGE to revise GHG emissions forecasts accordingly and provide narrative explanations of key planning insights from this exercise. Additionally, Staff Recommendation #5 is addressed through the inclusion of an SSR compliance analysis, in which PGE's compliance position is identified and potential cost impacts of compliance are considered using a SSR proxy resource in portfolio analysis.

6.1 Portfolio analysis design and scoring

PGE evaluated portfolios using the capacity expansion model, ROSE-E, over a 20-year time horizon from 2025 through 2044. Portfolios must satisfy all the constraints described in the sections that follow throughout the analysis timeline using the addition of available resources at the minimum possible cost. Portfolios are analyzed across 351 future scenarios representing combinations of conditions for need, price, and technology costs.[134] Where not otherwise stated, inputs, assumptions and methods are consistent with those described in the 2023 CEP/IRP.[135]

6.1.1 GHG emissions

PGE enforces compliance with HB 2021 GHG emissions targets in ROSE-E for the Preferred Portfolio and all scenarios except the 'Reliability Needs Only' analysis. Emissions decline according to the linear GHG glidepath described in **Section 3.5.1 HB 2021**.

[134] [39 Price] x [3 Need] x [3 Technology Cost] = 351 Future Scenarios
[135] See Chapter 11 Portfolio Analysis of the 2023 CEP/IRP, available here: https://edocs.puc.state.or.us/efdocs/HTB/lc80htb8430.pdf

6.1.2 Energy need

In the 2023 CEP/IRP, PGE required portfolios to meet energy needs on an annual basis, ensuring portfolios had sufficient energy on average throughout each year. For the first time in this Update, portfolio analysis uses a more-detailed monthly energy accounting to establish energy need, ensuring that portfolio add sufficient resources to meet projected energy needs in every month of the planning horizon. PGE's annual and monthly energy-load resource balances are presented in **Section 3.3 Energy need**.

Monthly energy accounting allows the interactions between seasonal variation in PGE's load and existing portfolio, and the generation profiles of proxy resources to be accounted for in resource selection. These seasonal dynamics can influence the optimal quantity and mix of resources in the portfolio. By increasing the granularity of accounting of energy-load resource balance from annual to monthly, ROSE-E is able to make more-optimal resource selections.

To incorporate monthly variation in energy from dispatchable sources, the monthly allocation of GHG-emitting energy is determined within ROSE-E by co-optimizing it with the selection of new resource additions. ROSE-E receives the maximum annual generation by each emitting source as an input from PGE's Intermediary GHG model (IGHG) and allocates that energy across the months of each year in a manner that minimizes the costs of new resource additions.

6.1.3 Capacity need

PGE updated forecasted summer and winter capacity needs for this analysis and they are described in **Section 3.4 Capacity need**. Portfolios are constrained to meet PGE's resource adequacy requirements in summer and winter every year. Capacity needs must be met through the addition of new proxy resources, as determined by their estimated ELCC. Proxy resource ELCCs are described in **Section 5.1.6 Resource capacity contribution**.[136] As a backstop source of capacity when the capacity from available resources is not sufficient to meet need, the model has access to a perfect capacity-fill resource (100 percent ELCC in summer and winter) to meet needs on a year-to-year basis.

6.1.4 Resource availability

ROSE-E has access to a variety of resource types to meet energy and capacity needs. These resources include renewables, storage, CBREs, distributed energy resources (DERs), and energy efficiency (EE). The variety of proxy resource types available for selection in portfolio analysis are described in **Chapter 5 Resource options**. To account for the time required for procurement through a request for proposals (RFP) process, the earliest that traditional supply-side resources can be added to the portfolio is 2029. The timing and available quantity of off-system resources is also a function of transmission availability, as described in **Section 6.1.5.1 Transmission constraints**. There is also a 500 MW annual limit on the addition of batteries to smooth the

[136] The State RA Requirements scenario relies on different capacity needs and proxy resource capacity contributions.

cadence of resource additions and prevent the model from relying on very large additions of storage in certain years.

CBREs and non-cost-effective (NCE) DERs and EE are available for selection beginning in 2026. Quantities available for selection of NCE demand response and energy efficiency have been updated for the Update and are described in **Section 5.2.3 Non-cost-effective demand response** and **Section 5.3.2 Non-cost-effective energy efficiency**. The quantity of CBRE's available for selection is unchanged from the 2023 CEP/IRP.[137] Prior to 2029, energy and capacity-fill resources are also available on an annual basis to allow the model to meet PGE's energy and capacity needs until sufficient quantities of supply-side resources become available for addition to the portfolio.

6.1.5 Transmission constraints and options

Assumptions about transmission represent one of the most impactful determinants of resource availability in portfolio analysis. These elements were incorporated into PGE's portfolio analysis for the first time in the 2023 CEP/IRP. This Update includes updated assumptions regarding constraints on the existing transmission system and the options to increase transmission capacity through upgrades and expansion. Off-system renewable resources must have associated transmission to be added to PGE's portfolio in ROSE-E. Transmission capacity can come from either estimated available regional transmission capacity (described in **Section 6.1.5.1 Transmission constraints**), or investment in additional transmission options (described in **Section 6.1.5.2 Transmission options**).

6.1.5.1 Transmission constraints

PGE's estimates of existing regional transmission availability are described in **Section 4.4 Assessment of available BPA point-to-point transmission**. Prior to 2032, when the first transmission option becomes available, the total quantity of off-system renewables available to be added to PGE's portfolio is limited to 2451 MW based on the quantity of available regional transmission capacity.

6.1.5.2 Transmission options

As part of a holistic transmission study for the Update, PGE has developed an updated set of options for transmission upgrades and expansion. The updated and expanded set of options includes three transmission upgrade options and four transmission expansion options. The quantity, timing, cost, and type of resource accessed are described in detail in **Section 4.6 Transmission options for portfolio analysis**. Both transmission upgrades and expansion increase the quantity of resources available for selection in ROSE-E. In portfolio analysis the two types of transmission actions allow access to additional resources in different ways. Transmission upgrades increase the capacity of PNW renewable resources that PGE can access across the

[137] See Chapter 7 of the 2023 CEP/IRP. Available here: https://edocs.puc.state.or.us/efdocs/HTB/lc80htb8430.pdf. PGE plans to update information about the cost and availability of CBRE resources for the 2026 CEP/IRP, leveraging information gained through the CBRE RFO described in **Section 7.1.2 CBRE action**.

regional transmission system. Transmission expansion options allow access to renewable resources and capacity markets outside of the PNW. Resources accessed through either transmission upgrades or expansion incur the cost of both the resource itself and the transmission required to deliver the energy to PGE's system.

6.1.6 Portfolio scoring

Portfolios are evaluated based on the traditional scoring metrics described in **Table 27** and the portfolio community benefits indicator (pCBI) metrics described in **Table 28**. The traditional scoring metrics for cost, variability and severity are the same that were used in the 2023 CEP/IRP and continue to provide valuable insights that ensure the Preferred Portfolio and Action Plan represent the best combination of cost and risks.

Table 27. Traditional portfolio scoring metrics

Metric	Description	Units
Cost	Net present value of revenue requirement (NPVRR), calculated for each of the 351 future scenarios for the analysis timeline (2025-2044). IRP costs consist of only those associated with existing and incremental generating resources (including associated transmission costs) and do not include other PGE costs (e.g. administrative costs, wildfire costs, etc.).	Million 2025$
Variability	Semi-deviation of NPVRR across all futures, relative to the Reference Case. This metric captures the potential variation in cost outcomes across futures, considering only futures in which NPVRR exceeds the Reference Case. Portfolios with low variability scores tend to provide more cost certainty and lessen the customer's impacts of higher-than-expected cost conditions.	Million 2025$
Severity	The tail value at risk (TailVAR) at the 90th percentile of the NPVRR across futures. This metric measures the potential magnitude of very high-cost outcomes across all futures. Portfolios with low severity scores tend to have less costly worst-case scenarios for customer cost impacts.	Million 2025$

The pCBI scoring metrics represent a substantially more thorough and detailed approach to measuring the level of community benefits provided by each portfolio than has been used in the past. pCBIs are unitless indicators that accrue for each MW of eligible resource that is added in a portfolio. A detailed description of the pCBI development, including a mapping of which proxy resources generate each of the pCBIs, is provided in **Section 5.5 Community benefits indicators (CBIs)**. Scoring outcomes for pCBIs of each portfolio analyzed are described in **Section 6.5 Portfolio CBIs.**

Table 28. Portfolio Community benefits indicator (pCBI) metrics

Metric	Description
pCBI 1 Economic Impacts	Economic development, increased access to jobs, economic well-being, increased productivity
pCBI 2 Energy Equity	Improved awareness and access to clean energy programs by environmental justice and tribal communities; increased affordability; increased efficiency of housing stock; reduced arrearages and disconnections
pCBI 3 Health and Community Wellbeing	Increased comfort; improved public health outcomes, particularly for environmental justice communities; reduced local emissions; improved home health and safety (including indoor air quality)
pCBI 4 Resilience / Reliability	Improved grid resiliency; increased resilience/reliability in environmental justice communities, including reduced recovery time and frequency of outages
pCBI 5 Environmental Impacts	Reduced air emissions, including CO_2 and criteria pollutants

6.2 Preferred Portfolio

PGE's updated Preferred Portfolio demonstrates the least-cost, least-risk, set of resources needed to meet resource adequacy needs while decarbonizing in accordance with HB 2021 through the year 2044. **Table 29** shows the optimized resource additions made in ROSE-E as well as cost-effective quantities of EE and DERs and the 2023 RFP proxy, through the year 2030. The supply-side energy and capacity resources added in ROSE-E represent generalizations of resources that may become available for acquisition through an RFP process in which actual projects will be compared on the basis of project-specific costs and benefits. Near-term non-emitting and capacity contracts represent opportunities that PGE could pursue through bilateral contract negotiations.

Optimized resource additions through 2030 include 1362 MW of wind, 1089 MW of solar, 1750 MW of storage, 83 MW of NCE EE and DERs, and 155 MW of CBREs. The 2030 resource mix also includes 190 MW of non-emitting contracts. This 4629 MW of incremental resource additions made through 2030 represents a 16 percent increase compared to the 3984 MW of resource additions in the final 2023 IRP Preferred Portfolio.[138] The bulk of the increase in 2030 resource additions is comprised of storage, which has roughly doubled compared to the 869 MW (including hybrid storage) in the 2023 CEP/IRP final Preferred Portfolio. The increase in storage additions is largely driven by a decrease in PGE's calculated capacity contribution of those resources. As described in **Section 5.1.7 Comparison of resource capacity contribution to**

[138] The final Preferred Portfolio from the 2023 CEP/IRP was published in PGE's response to Staff Round 2 Comments. Updated resource need reporting conventions introduce some complexities when comparing current projections of resource need to past disclosures. The comparison made here uses the updated convention of identifying hybrid storage separately for the calculation of total resource need for both portfolios. PGE's response to Staff Round 2 Comments is available here: https://edocs.puc.state.or.us/efdocs/HAC/lc80hac154444.pdf

2023 CEP/IRP, the ELCC of the 4-hr battery proxy resource has decreased by 33 percent in summer and 50 percent in winter compared to the 2023 CEP/IRP.

The selection of 68 MWa of NCE EE in optimized portfolio construction highlights the potential for accelerated procurement of EE to lower portfolio costs in a transmission-constrained planning environment over the long-term. However, as discussed in Section 11.4 of the 2023 CEP/IRP, including additional quantities of EE in the portfolio has the potential to create near-term customer cost impacts because of unique policy factors associated with these resources. Unlike other assets, additional EE is not financed or securitized, which can increase near-term cost impacts relative to other resource options. As discussed in **Section 5.3.5 Energy efficiency program and policy**, PGE is committed to working with Energy Trust of Oregon on multiple potential avenues to address the cost and implementation challenges associated with accelerated procurement of EE.

Notably, this first year of transmission availability in 2032 is five years later than the 2027 date of first-available transmission option in the 2023 CEP/IRP. The reliance on some non-emitting contracts through 2031 highlights the impact of transmission constraints on off-system resource additions prior to the first opportunity for transmission upgrades in 2032.

Table 29. Cumulative resource buildout of the Preferred Portfolio 2026-2030 (MW)

Resource	2026	2027	2028	2029	2030
Wind	0	0	0	1362	1362
Solar (including hybrids)	0	0	0	1089	1089
Storage (including hybrids)	0	0	0	1250	1750
CBREs	66	85	110	133	155
NCE EE (MWa)	0	21	38	58	68
NCE DERs	3	8	12	13	15
Transmission	0	0	0	0	0
Non-Emitting Contracts*	16	422	120	33	190
Cost-effective EE (MWa)	104	138	173	208	245
Cost-effective DR	142	172	199	225	248
2023 RFP Proxy Solar (including hybrids)	0	0	375	375	375
2023 RFP Proxy Storage (including hybrids)	0	0	775	775	775

*** Values for contracts are annual, not cumulative.**

Post-2030 results show that all seven transmission options are added to the portfolio between 2032 and 2038, unlocking access to the energy and capacity of 6927 MW of off-system

renewables (**Table 30**).[139] The addition of all 6927 MW of transmission options illustrates the importance of evaluating and consider taking action on transmission opportunities, both through upgrades and partnering-on or investing-in proposed transmission expansion projects, in order to access off-system renewables and energy markets. This aspect of the Preferred Portfolio differs substantially from the content of the 2023 CEP/IRP Preferred Portfolio, which included only 1200 MW of available transmission options (all of which were added in the Preferred Portfolio) and instead relied heavily on generic capacity and renewable resources post-2030. The comprehensive and detailed list of most-appropriate transmission options potentially available to PGE, modeled in this Update provides a substantially more well-defined look at the mix of resources that may become available to meet energy and capacity needs in the 2030's and beyond. In contrast to the generic transmission options used in the 2023 CEP/IRP, the transmission options added to this Preferred Portfolio represent specific opportunities (modeled with somewhat generalized resource cost characteristics). The transmission options, identified with the help of consultant Energy Strategies, are described in detail in **Section 4.6 Transmission options for portfolio analysis**.

Table 30. Cumulative resource buildout of the Preferred Portfolio 2031-2038 (MW)

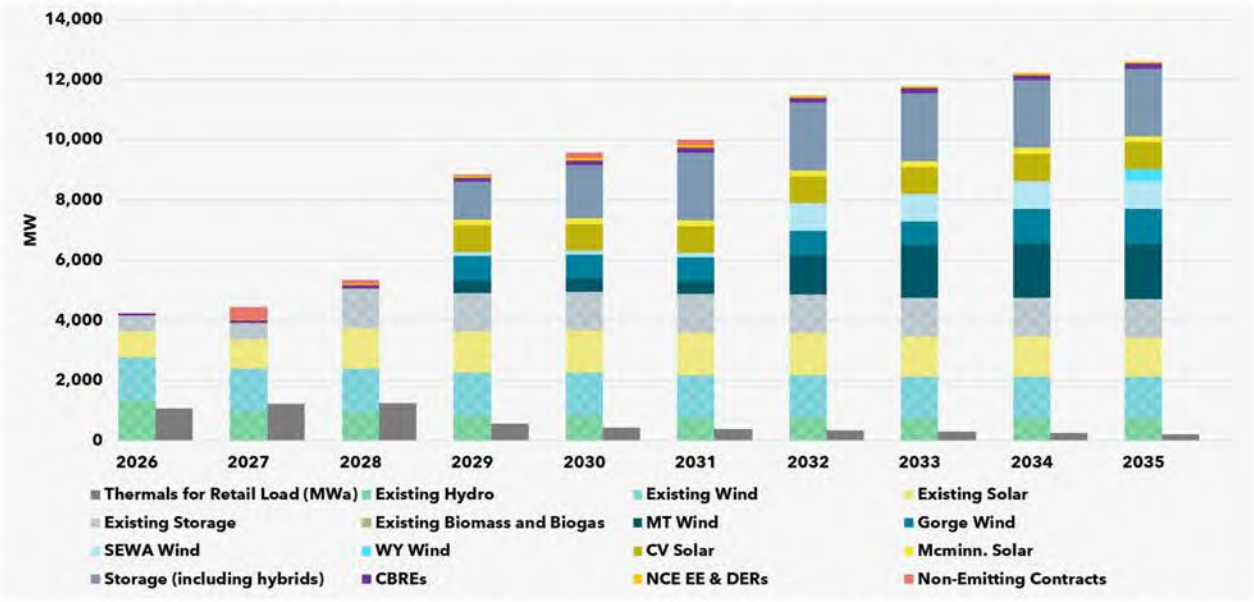
Resource	2031	2032	2033	2034	2035	2036	2037	2038
Wind	1362	2989	3420	3844	4274	4761	5352	5947
Solar (including hybrids)	1089	1089	1089	1089	1089	1089	1089	1089
Storage (including hybrids)	2250	2250	2250	2250	2732	3232	3732	4232
CBREs	155	155	155	155	155	155	155	155
NCE EE (MWa)	68	68	68	68	68	68	68	68
NCE DERs	16	16	16	16	16	16	16	16
Transmission	0	3000	3000	3000	5227	5227	5227	6927
Non-Emitting Contracts*	187	0	0	0	0	0	0	0
Cost-effective EE (MWa)	281	317	352	384	415	446	478	510
Cost-effective DR	266	284	299	312	325	336	348	356
2023 RFP Proxy Solar (including hybrids)	375	375	375	375	375	375	375	375
2023 RFP Proxy Storage (including hybrids)	775	775	775	775	775	775	775	775

*** Values for contracts are annual, not cumulative.**

[139] Some of the transmission options also provide additional capacity through access to diverse energy markets. In the 2023 CEP/IRP final Preferred Portfolio, transmission options did not provide additional capacity associated with diverse market access.

The cumulative addition of the Preferred Portfolio's incremental resources to PGE's existing resource portfolio are shown in **Figure 57**. The quantity of energy retained from existing emitting sources, in average Megawatts (MWa), can be seen to decline through time in accordance with the GHG glidepath that leads to compliance with HB 2021 emissions targets in 2030 and beyond. Incremental resource additions experience a large jump in 2029 when the first supply-side resources become available and another smaller jump in 2032, when the Bethel-Round Butte transmission upgrade unlocks access to 3000 MW of additional off-system renewable resources. The quantity of resources in PGE's existing portfolio varies through time, increasing in 2028 with the addition of 2023 RFP Proxy resources, and declining at various points in time as certain contracts expire. By 2030, the 4629 MW of incremental resource additions in the Preferred Portfolio are nearly equal to the nearly 5 GW of non-emitting resources already expected in PGE's existing portfolio at that time.

Figure 57. Preferred Portfolio Resource Additions (MW)[140]

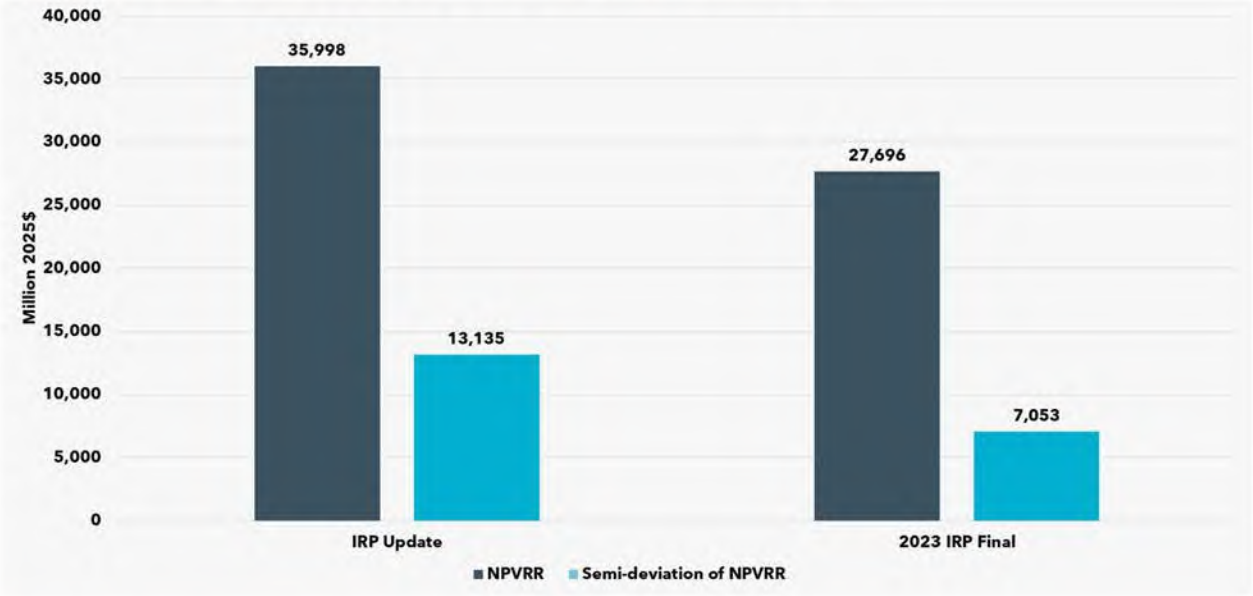


Costs of the updated Preferred Portfolio are larger than those of the final Preferred Portfolio from the 2023 CEP/IRP.[141] Across the full 20-year planning horizon the updated Preferred Portfolio has an NPVRR of $35,998 million, which is a $8,302 million increase from the $27,696 million NPVRR of the final 2023 CEP/IRP Preferred Portfolio (**Figure 58**).[142] The increase in portfolio cost is driven by a combination of increased quantity of resource additions and increased $/kW-yr resource costs projections for some types of supply-side resources, as described in **Section 5.1.2 Supply-side resource costs**. These drivers of increased cost outweigh the cost-reducing impacts of having a more well-defined set of transmission options that have reduced reliance on the expensive generic capacity and VER resources that were relied on heavily in the post-2030

[140] Existing resource quantities include 2023 RFP Proxy.
[141] The final Preferred Portfolio from the 2023 CEP/IRP was published in PGE's response to Staff Round 2 Comments. Available here: https://edocs.puc.state.or.us/efdocs/HAC/lc80hac154444.pdf
[142] Portfolio costs in the 2023 CEP/IRP were reported in 2023 $'s and have been adjusted to 2025 $'s for this comparison.

resource buildout of the 2023 CEP/IRP Preferred Portfolio. Additional detail on the annual costs of the Preferred Portfolio is provided in **Section 6.2.1 Yearly cost estimates**.

Figure 58. Cost and Risk Metrics of the Preferred Portfolio (MW)



6.2.1 Yearly cost estimates

The purpose of this section is to show yearly cost estimates of proxy new resource additions in the Preferred Portfolio under a set of utility ownership and tax credit assumptions. This section provides updated results compared to those presented in Section 11.3 of the 2023 CEP/IRP. The Preferred Portfolio was run through a version of the Annual Revenue-requirement Tool (ART) that contains updated input data. The ART uses reference load presented in **Chapter 3 System needs** and existing and incremental proxy resource costs described in **Chapter 5 Resource options**.

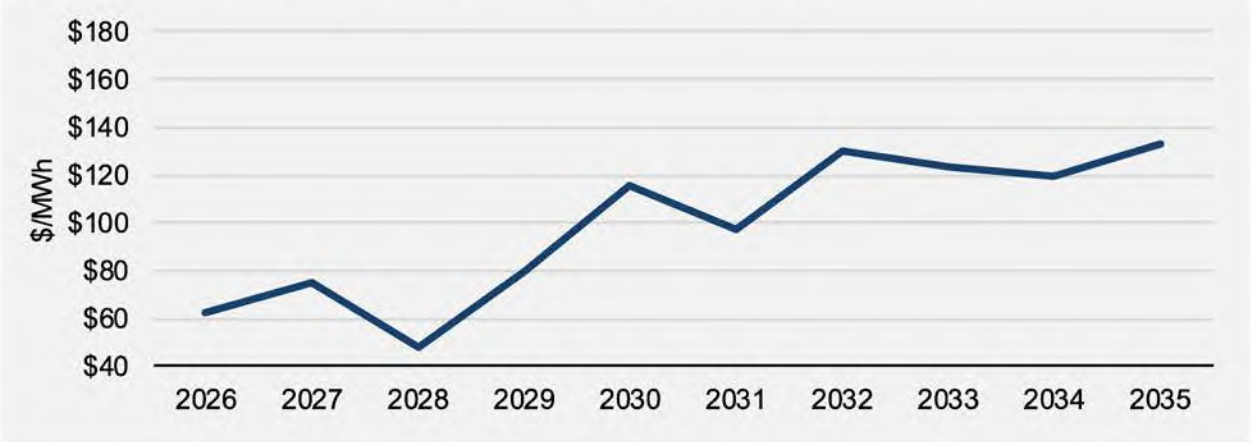
The model incorporates the impact of market sales on an annual basis and can evaluate different combinations of ownership structures and tax incentives for each portfolio.[143] Market purchases and thermal sales are calculated on an annual basis within the Intermediary GHG (IGHG) model and imported to ART. Further, ART only focuses on existing and new generating resources, including associated estimated transmission expansion costs. Estimates do not include costs from the rest of PGE, such as those associated with administrative costs, grid modernization, other transmission and distribution maintenance and upgrades, wildfire mitigation or actual generation costs. Caution is warranted in interpreting these estimates, as these values reflect a change in forecasted annual costs of real and proxy generating assets that only represent a subset of PGE's total annual cost. Accordingly, these yearly price impacts do not represent actual customer price impacts (expressed either as total or a percent) as they only focus on planned generation and transmission expansion cost changes and do not incorporate any other cost

[143] Modeling assumption of the ownership structures do not impact or reflect future procurement approaches nor prejudge outcomes of future procurement processes.

changes across PGE. Additionally, the cost impact uncertainty due to ongoing policy discussions regarding cost allocation to large industrial customers and the resulting unequal and evolving distribution of costs between customers classes is another factor making the results presented here not reflective of actual customer rate impacts. This topic is explored in more detail in through the sensitivity analysis presented in **Section 6.3.3 Large industrial customer growth**.

The price impacts can still be indicative for evaluating options to decarbonize reliably. Through an extensive analysis of resource additions amongst a variety of portfolios, PGE finds that while the incremental resource additions included in these estimates represent the least cost and risk manner to meet the emissions targets established in HB 2021, they are anticipated to raise the costs associated with generation resources relative to today. These Reference Case price changes are shown in **Figure 59** and include a 50 percent ownership assumption and full ITC/PTC tax credits available for relevant resources. This $/MWh annual price represents the modeled cost estimates divided by total PGE load described in **Section 3.1.1 Energy forecast**. Incremental resource additions, including the expansion of the existing transmission system, continue to increase the costs of generation resources through 2035 and beyond. While this analysis does not represent actual changes to customer prices, it is suggestive that, on a planning basis, system costs are likely to increase to comply with HB 2021.

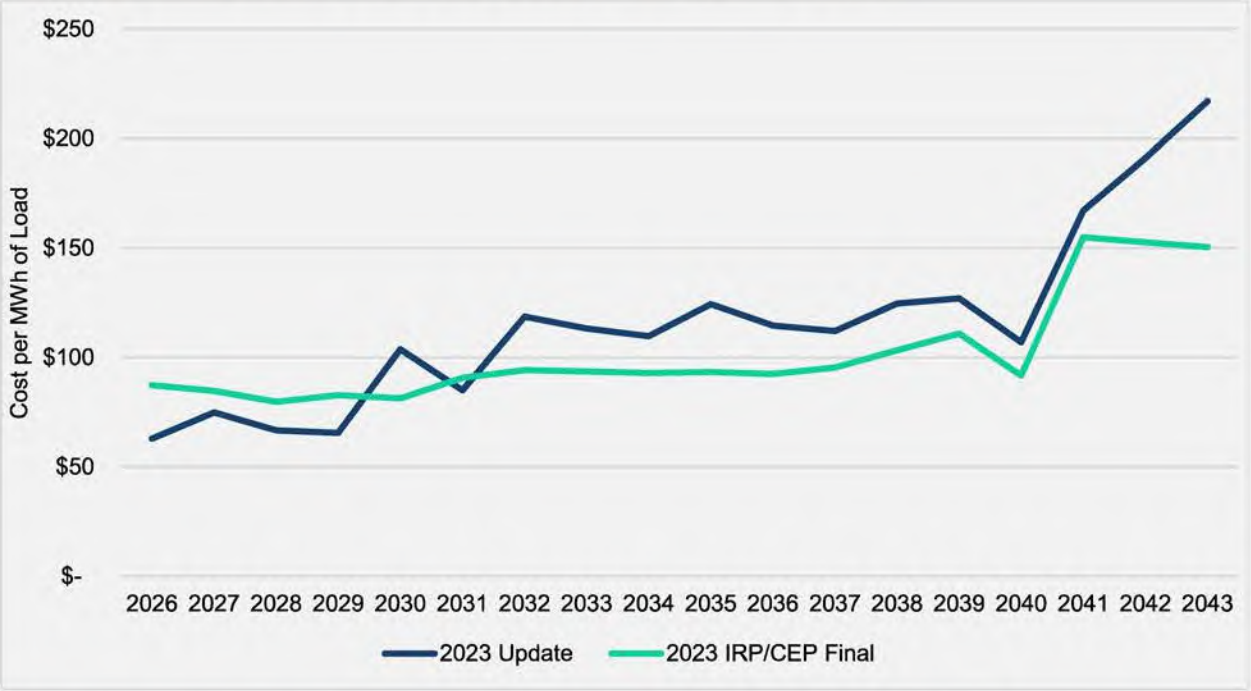
Figure 59. Reference Yearly Price Impacts ($/MWh) of the Preferred Portfolio



As discussed in previous chapters, the 2023 RFP procurement results are not yet final, but based on ongoing negotiations, no new non-emitting resources identified through this RFP can be contracted prior to a January 1, 2028 COD. Incremental resource additions (and associated costs) prior to 2029 are for CBREs and DERs. After this time, the models add much more non-emitting resources to reduce thermal generation serving retail load in order to meet HB 2021 compliance as well as maintain resource adequacy. The yearly cost forecast supports the finding described above and previously in the 2023 CEP/IRP that GHG emission reductions lead to cost increases. **Figure 60** compares the updated yearly price estimates to those presented for the Preferred Portfolio in the 2023 CEP/IRP updated for the final Preferred Portfolio. Total costs are a bit higher in the Update after 2035 and the updated retail load forecast is higher, allowing costs to be spread across more MWhs. In the updated analysis, PGE has replaced generic capacity and energy resources with actual modeled resources which are more cost effective than the generic

capacity and energy resources. These were unavailable in the 2023 IRP due to transmission limitations. While these transmission expansion options have costs associated with them, they are significantly cheaper than the generic capacity and energy resources. The overall increase in costs is due to increased resource additions and increased costs with some resource types.

Figure 60. Comparison of Reference Yearly Price Impacts ($/MWh)



Given the constraints in the planning environment associated with HB 2021 decarbonization goals, load growth, and transmission availability, the need for resource procurement identified in this Update continues to be large and is estimated to result in substantial cost impacts. Included in load growth expectations are significant increases in large new loads which account for between 30 percent to 80 percent of load growth forecast in any given year, averaging 47 percent over the 20-year period. These new large loads significantly increase PGE's need to acquire new resources, increasing total load by about 20 percent by 2044. PGE constructed a Preferred Portfolio that minimizes the costs and risk of new resource acquisitions and maximizes the provision of community benefits by thoroughly investigating key decision points with the potential to impact costs. This includes the selected GHG emissions-reduction pathway described in **Section 3.5.1 HB 2021** that complies with HB 2021 requirements while mitigating costs relative to more aggressive pathways and reducing risks compared to less aggressive pathways. Mitigating the impact of cost increases is critical and PGE will continue to study options that can help minimize costs for customers, including maximizing acquisition of cost-effective energy efficiency, continuing to explore the potential of emerging technologies as they develop and studying options to expand transmission access to cost-effective non-emitting resources.

6.2.2 Hourly energy and emissions accounting results

This section expands upon Chapter 5 of the 2023 CEP/IRP to reflect the hourly energy accounting and resulting GHG emissions impacts of the Preferred Portfolio. In the 2023 CEP/IRP, PGE demonstrated compliance with HB 2021 using annualized estimates of emissions of thermal generation and unspecified market purchases under a variety of GHG reduction glidepaths. In the December 14, 2023, Public Utility Commission of Oregon Staff report on docket LC 80, Staff identified that PGE's annual GHG emissions approximations neglected important aspects of system operations that may impact the Company's annual GHG emissions accounting. Staff highlighted the need for an hourly dispatch analysis to confirm PGE's GHG emissions projections and demonstrate its ability to comply with HB 2021. In Order 24-096, the OPUC directed PGE to resubmit a revised plan with its CEP/IRP Update in 2025 consistent with Staff Recommendation 3, stating that:

- PGE shall conduct hourly production cost simulation of its Preferred Portfolio under the reference case in a manner that separately tracks hourly purchases and hourly sales.
- PGE will use this analysis to revise its GHG emissions forecast to revise its submission to the DEQ.
- PGE shall update the Preferred Portfolio accordingly and provide a narrative explanation of the key planning insights derived from this exercise.[144]

In this Update, PGE addresses the requirements outlined above using a modified version of its PGE-Zone Model (PZM) to simulate hourly energy and emissions positions. This model is referred to as the Modified PGE-Zone Model (mPZM). The mPZM performs hourly production simulations under Reference case conditions in a manner that tracks hourly resource operation, market purchases, and market sales based upon supply and demand conditions.

The mPZM uses outputs from the PZM, the Brattle Clean Energy Surplus Model (CESM), Intermediate GHG Model (IGHG), and the Preferred Portfolio from ROSE-E portfolio development as inputs. Hourly and annual constraints are added to prevent emitting generation and unspecified market purchases from exceeding quantities specified by HB 2021 emissions limits. Additional details of how PGE applies the hourly energy and emissions accounting methodology are set forth in **Appendix D Hourly emissions methodology**. The results of this simulation indicate that, based upon forecasted market conditions, PGE's Preferred Portfolio can comply with HB 2021 emissions limits in 2030.

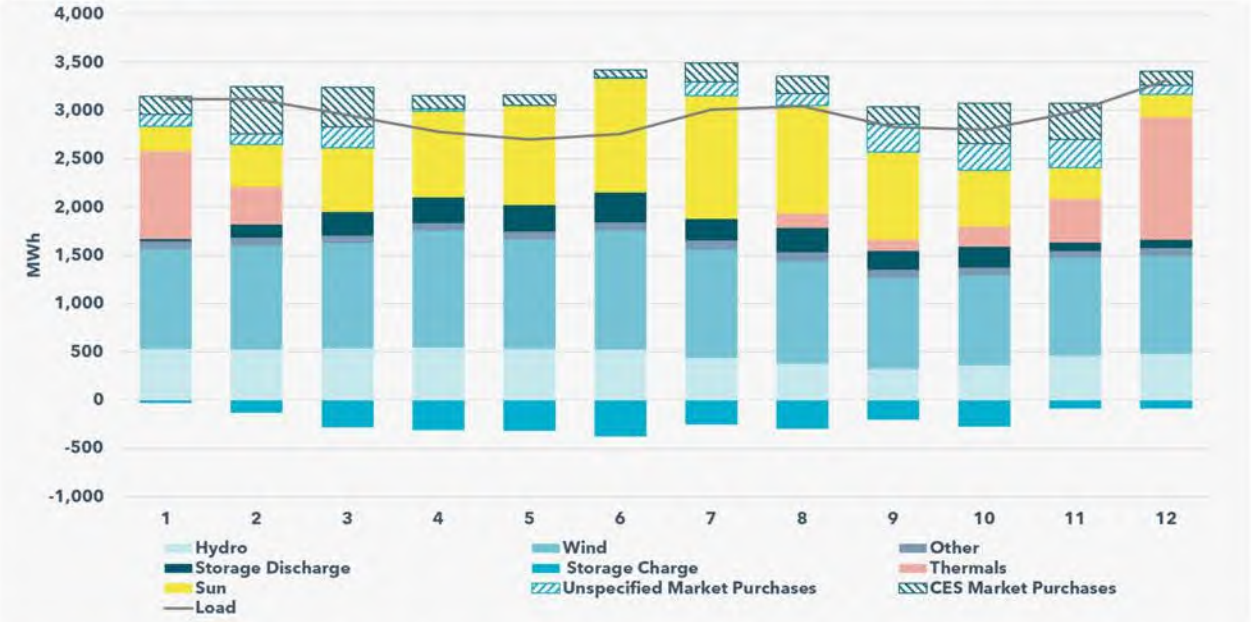
The following sections provide the results of this hourly mPZM analysis. First, a summary of monthly results demonstrates how emissions compliance is achieved; next, assumptions regarding market availability are detailed; generation from thermal resources are summarized; finally, example weeks in June and December provide greater detail on model results.

[144] https://apps.puc.state.or.us/orders/2024ords/24-096.pdf

6.2.2.1 Summary of results

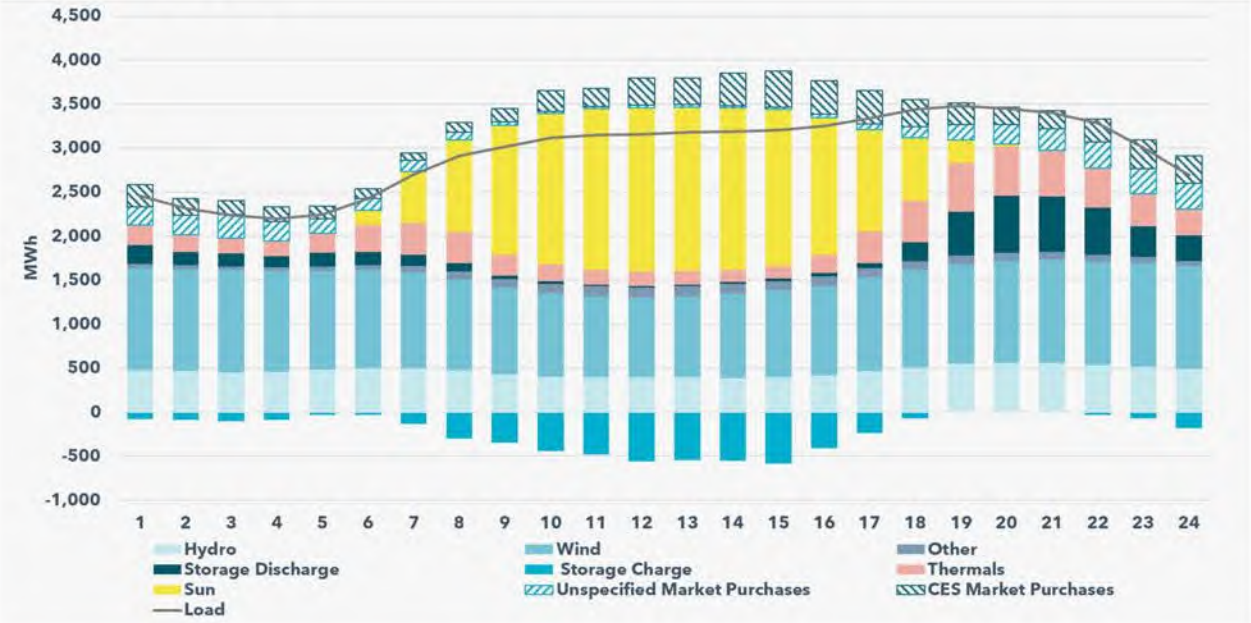
Figure 61 demonstrates the composition of supply used to meet demand for each month in 2030. Thermal generation is concentrated in the winter when non-emitting energy is scarce. Storage charging and discharging occurs in the spring, when storage opportunities to levelize net demand across the day is most present. Market purchases from non-emitting sources (clean energy surplus or "CES") are concentrated in the shoulder months across hours when the premium for such energy relative to the unspecified market (premium for clean energy or "PFC") is low. Unspecified market purchases are largley allocated outside of the spring months.

Figure 61. Monthly Modified PZM results show the simulated generation (MWh) by resource type across 2030



The composition of supply used to meet demand for the average day in 2030 is demonstrated in **Figure 62**. Thermal generation and storage discharge are concentrated over the peaks of the day. Storage charging occurs primarily during midday solar hours. Clean energy surplus market purchases are more frequent midday, during solar hours, as well, and unspecifed market purchases occur most frequently over the evening and early morning periods.

Figure 62. Hourly Modified PZM results show the simulated MWh by resource type across an average day in 2030



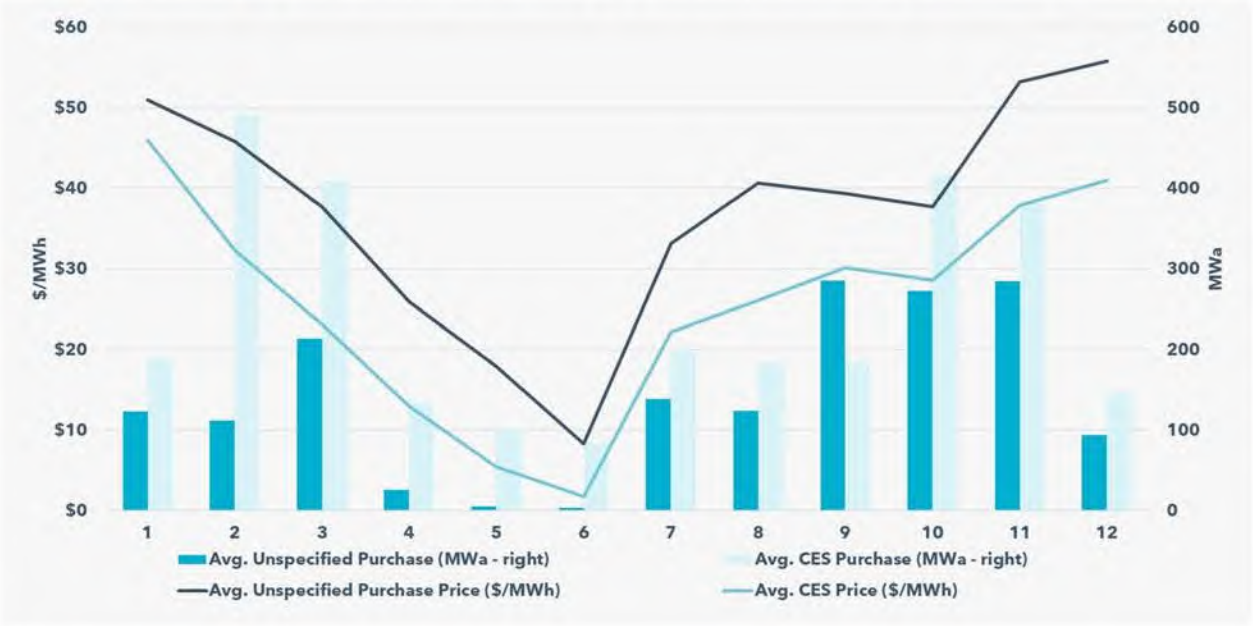
6.2.2.1 Assumptions of market availability

These simulations assume that when PGE's hourly position is long generation (supply exceeds retail demand), the excess generation contributes towards market sales. The thermal output dispatched by the Modified PZM optimization demonstrates the portion of thermal generation dedicated to serve retail load. Any additional wholesale sales of thermal generation will not be represented in the Modified PZM output. Any additional wholesale sales in the Modified PZM are a function of excess non-thermal resources such as periods of ample wind and solar generation and/or the presence of hydro must-run conditions. The periods in which the simulation results in PGE selling into the market are generally April–July. The timing of these long positions tends to align with periods of clean energy surplus across the WECC as the premium for clean energy is near zero during hours of most sales. This is demonstrated in **Figure 63** where the columns depict the average market sales volume (MWa) by month. The average realized price (the market price plus the premium for clean energy) is represented by the dark blue line, and the average premium for clean energy is shown as the red line. Given that non-emitting generation is greatest in the spring, as shown above, PGE market sales also tend to occur predominantly in the spring.

Figure 63. Average Hourly Revenue on Market Sales by Month

Figure 64 shows the timing of both unspecified and clean energy surplus market purchases in the mPZM simulation; the price of clean energy surplus market purchases includes the additional premium for clean energy. The methodology first assigns unspecified market purchases to hours with the highest premium, up to the portion of PGE's 2030 emission budget allocated to unspecified market purchases by the IGHG model. Clean energy surplus market purchases then fill remaining hours of need based on the quantity and timing of availability detailed in the Brattle report provided in **Appendix F Market for non-emitting energy**. Total market purchases average 382 MWa for the year, with 141 MWa allocated to unspecified purchases and 241 MWa allocated to CES purchases. Please see PGE's discussion of market developments in **Section 2.2.1 CAISO's Extended Day Ahead Market**.

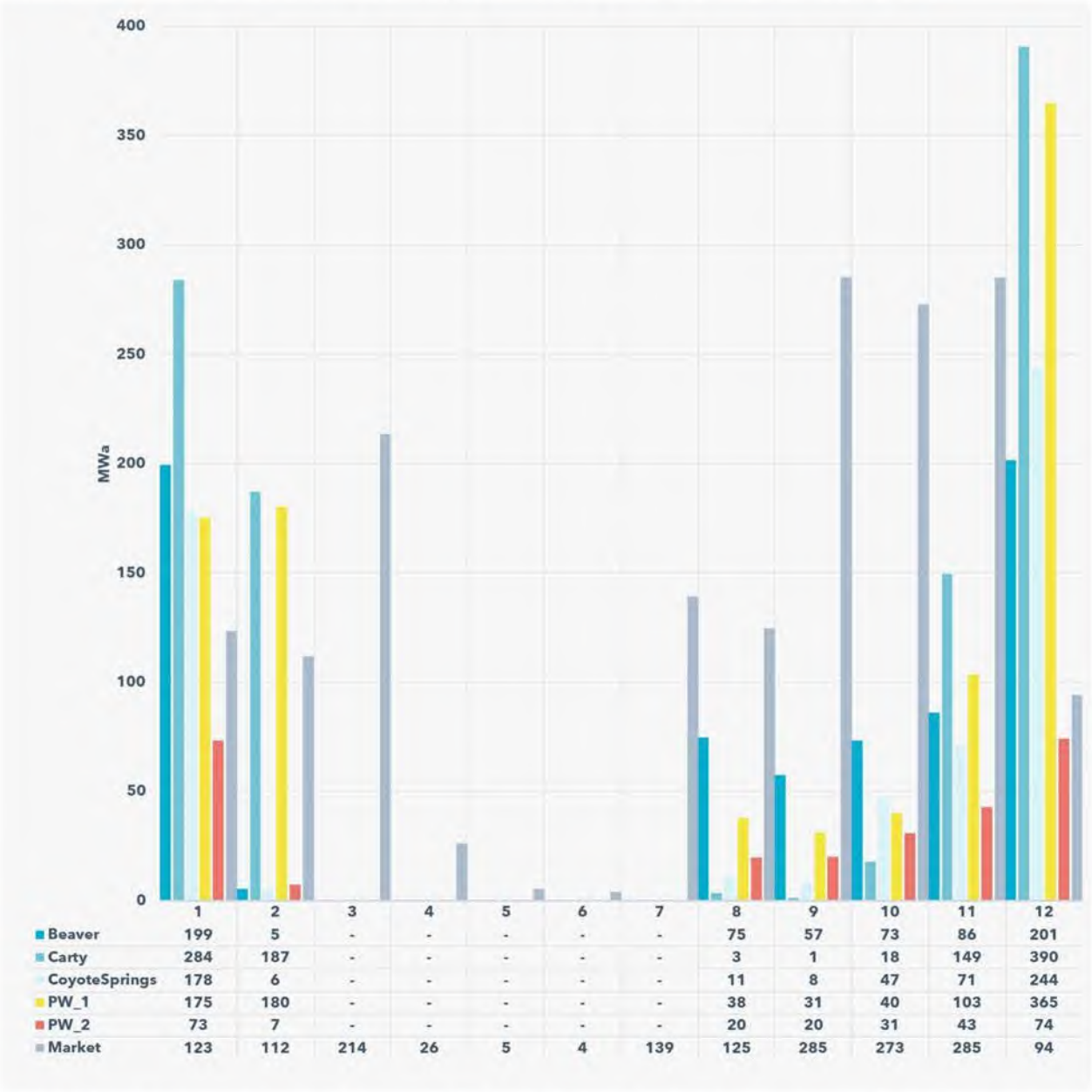
Figure 64. Timing of both unspecified and CES market purchases in the mPZM simulation



6.2.2.1 Thermal generation

Thermal generation allocated to serve PGE retail load is capped at the annual generation levels determined in the IGHG model. The mPZM optimizes emitting resource generation allocated to the retail portfolio across 2030 up to the IGHG limits. **Figure 65** shows the timing of emitting generation by month for the 2030 simulation.

Figure 65. Monthly generation (MWa) by emission source across 2030 forecast

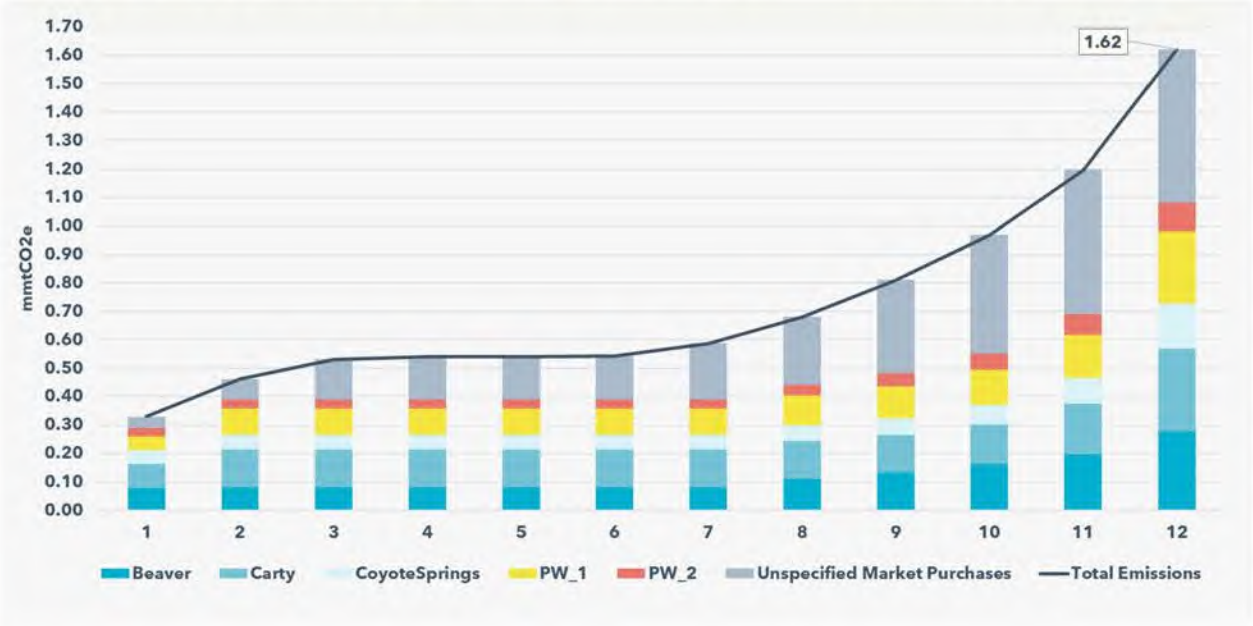


	1	2	3	4	5	6	7	8	9	10	11	12
Beaver	199	5	-	-	-	-	-	75	57	73	86	201
Carty	284	187	-	-	-	-	-	3	1	18	149	390
CoyoteSprings	178	6	-	-	-	-	-	11	8	47	71	244
PW_1	175	180	-	-	-	-	-	38	31	40	103	365
PW_2	73	7	-	-	-	-	-	20	20	31	43	74
Market	123	112	214	26	5	4	139	125	285	273	285	94

Since thermal generation and unspecified market purchases are capped, the emissions associated with serving retail load are designed to meet the HB 2021 emission limit of 1.62 million metric tons of CO_2 ($mmtCO_2e$). The timing of emissions is concentrated most heavily in the winter months as shown **Figure 66**. Approximately 60 percent of all simulated emissions occur in January, November, and December. This summary shows how PGE could use its emitting resources in a planning context, given the Preferred Portfolio and market assumptions detailed above, to meet portfolio needs within the 2030 emission targets. While the Update's simulation thermal operations in 2030 identifies how thermal output can be forecasted, PGE recognizes that many operational considerations and market complexities are challenging to

fully incorporate into planning. These differences prevent precise estimates of future operating conditions.

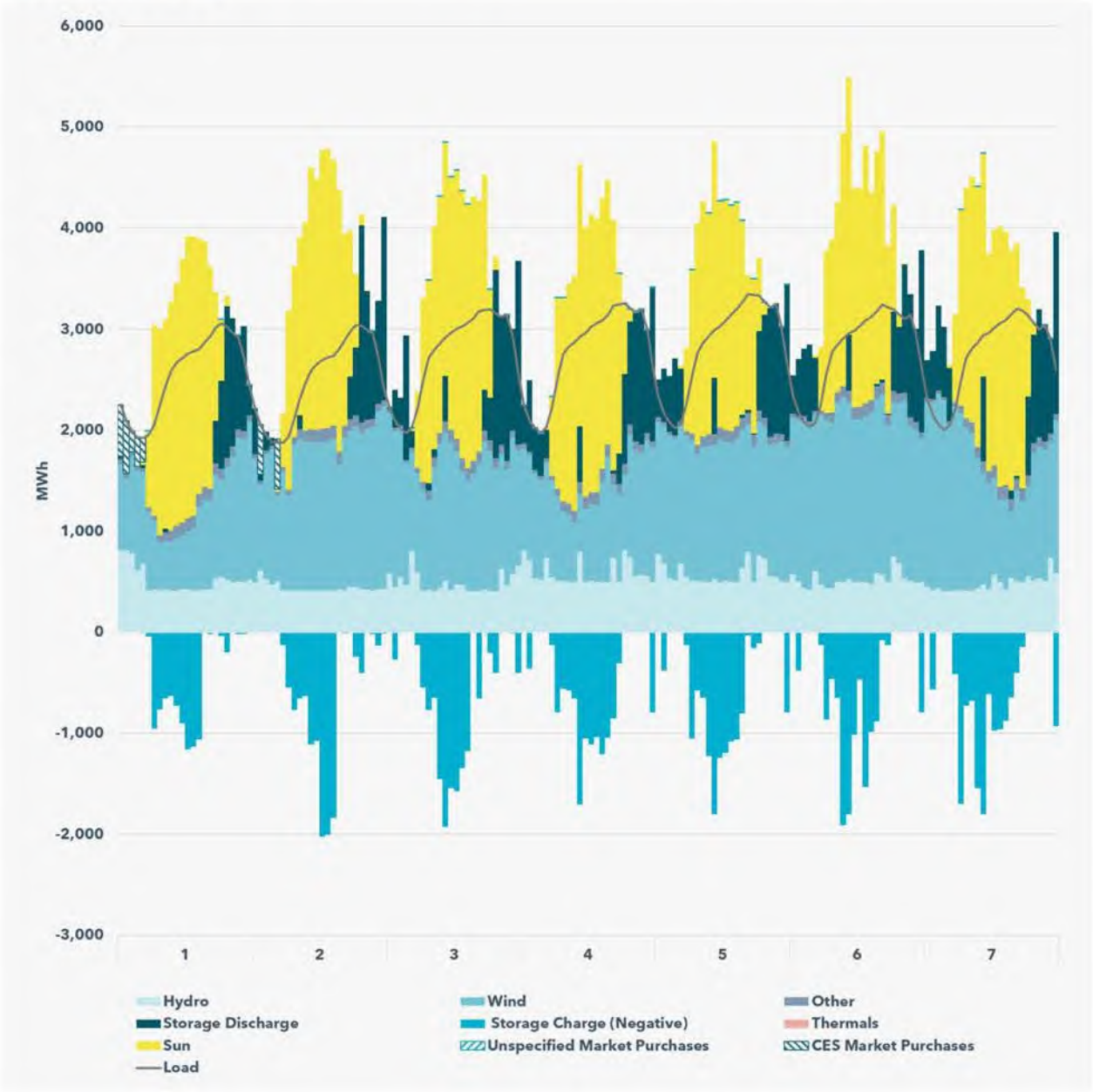
Figure 66. mPZM simulated 2030 monthly cumulative emissions (mmtCO2e) by source



6.2.2.1 Hourly generation snapshots

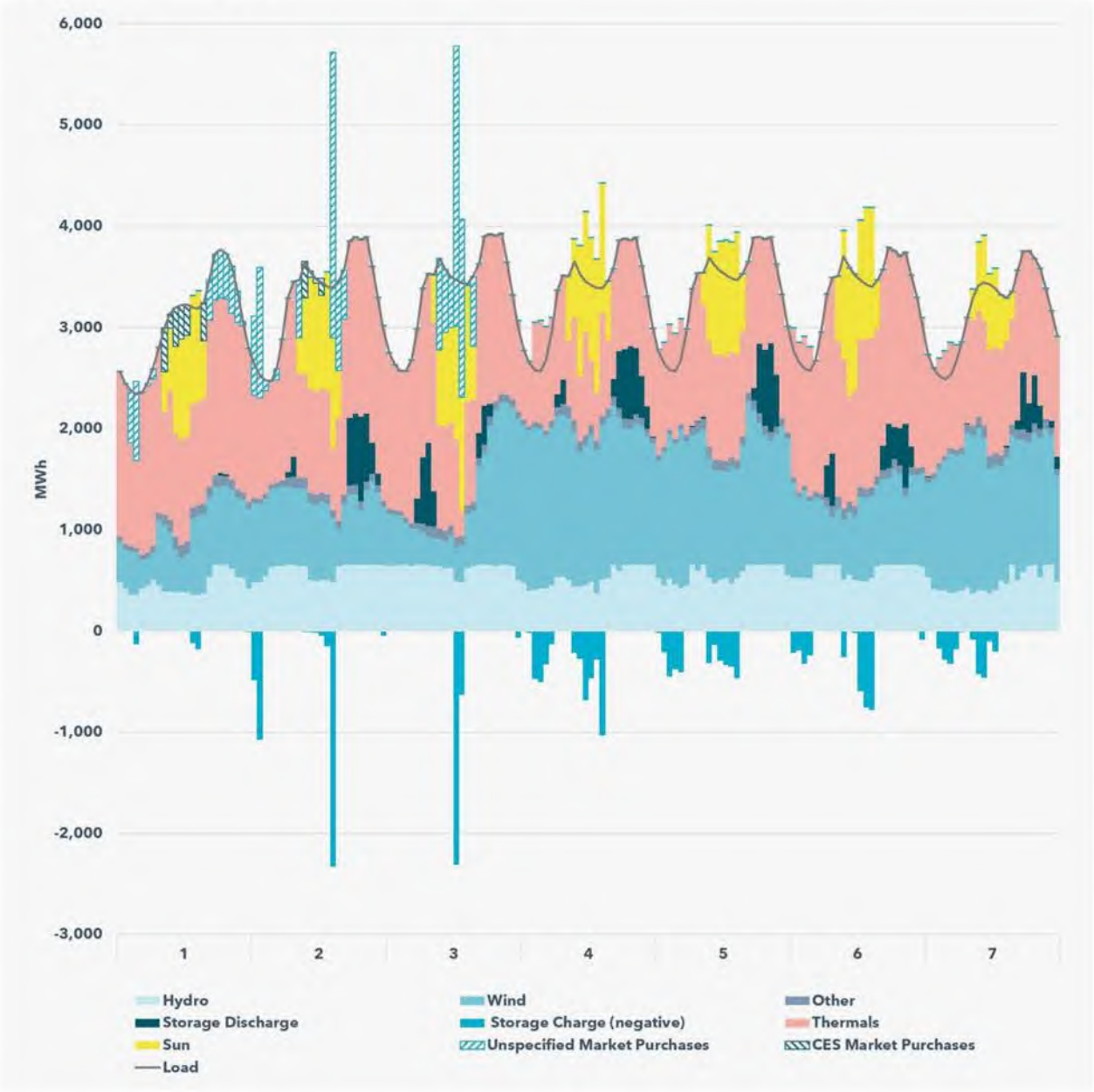
To demonstrate more granular representations of the mPZM results, sample weeks with hourly values by resource type are provided (**Figure 67**). The results include the first seven days of the month for June and December 2030 to demonstrate seasonal variation. June is punctuated by solar and wind generation with storage resources utilized to smooth the daily load-resource balance.

Figure 67. Hourly mPZM snapshots show simulated supply and demand positions by resource type in June 2030



In December 2030, thermal generation is deployed as PGE non-emitting generation is volatile and scarce while market premiums for clean energy are high (**Figure 68**). Unspecified market purchases are leveraged to charge batteries midday so they can be dispatched across evenings and early mornings.

Figure 68. Hourly mPZM snapshots show simulated supply and demand positions by resource type in December 2030



6.2.3 Preferred Portfolio resource adequacy testing

To ensure that the Preferred Portfolio can meet PGE's reliability needs, the Update analyzes the portfolio's specific resource configuration in the Sequoia adequacy model. This test evaluates how adequate the system is after including the Preferred Portfolio and assesses whether the ELCCs used in capacity expansion modeling remain valid when considering the dynamic system interactions present in a portfolio of resources.

The Company's capacity expansion model ROSE-E is constrained to meet system need (**Section 6.1.3 Capacity need**) utilizing an estimate of proxy resource capacity contributions or ELCCs

(**Section 5.1.6 Resource capacity contribution**). The estimation incudes two simplifications that PGE validates when assessing adequacy of the Preferred Portfolio. First, ELCCs are estimated in 2030 only, as estimating ELCCs in Sequoia is a computationally intensive and prolonged process. Second, ROSE-E interprets ELCCs as additive, where the addition of one resource does not affect the ELCCs of another. However, the capacity contribution of a resource is dynamic relative to system demand and supply across time. Including the Preferred Portfolio in Sequoia provides a more granular assessment of its effect on system reliability and appropriateness of the simplifications above. If abstractions used in capacity expansion modeling are representative of the dynamic system, the adequacy effect of the Preferred Portfolio would result in zero capacity need and a 2.4 loss-of-load hours (LOLH) adequacy metric.

Table 31 details the seasonal capacity need of PGE's system after including the Preferred Portfolio. These estimates show the portfolio is estimated as adequate in summer and winter seasons for 2026 through 2030, except a remaining capacity need in winter 2028 of 68 MW. As discussed in **Section 3.4 Capacity need**, structured or bilateral contracts that may be facilitated by State RA participation are tools PGE may use to procure capacity in the short-term.

Table 31. Reference Seasonal Capacity Need with Preferred Portfolio Resources

Year	Summer Need (MW)	Winter Need (MW)
2026	0	0
2027	0	0
2028	0	68
2029	0	0
2030	0	0

Analyzing the frequency of unserved energy events provides insight into how adequate the system is in future years. **Table 32** displays the LOLH metrics that correspond to the capacity need estimates above. Estimates greater than 2.4 LOLH indicate positive capacity needs. For example, the capacity need of 68 MW in winter 2028 represents a system with 2.01 hours of unserved energy per year greater than the threshold. Conversely, estimates less than 2.4 LOLH provide a measure of the degree of system adequacy. In 2030, the Preferred Portfolio additions result in an adequate system in both summer and winter. However, the higher LOLH metric in winter suggests that meeting reliability in the winter is the active constraint in PGE's capacity expansion.

Table 32. Seasonal LOLH of PGE system with Preferred Portfolio Resources

Year	Summer LOLH	Winter LOLH
2026	2.27	0.03
2027	1.45	0.20
2028	0.41	4.41
2029	0.00	0.06

Year	Summer LOLH	Winter LOLH
2030	0.06	2.25

The results above indicate that the ELCC simplifications used by ROSE-E are reasonably accurate for identifying an adequate portfolio, as shown by the approximately exact capacity built for winter 2030. Additionally, and as discussed further below, winter adequacy challenges appear to be the cause of significant resource additions in the Preferred Portfolio.

6.2.3.1 Energy sensitivity adequacy assessment of Preferred Portfolio

The Update includes an energy sensitivity analysis of the Preferred Portfolio to further PGE's understanding of cost and reliability implications driven by winter adequacy challenges. This analysis aims to identify the nature of PGE's capacity needs decomposed from PGE's energy needs.

To conduct the energy sensitivity assessment, all 4679 MW of nameplate resources in the Preferred Portfolio were partitioned into 2879 MW of resources required to meet ROSE-E's energy need including solar and wind (Energy Only Preferred Portfolio) and 1800 MW of storage resources.[145] The Energy Only Preferred Portfolio was added to the PGE system as modeled in Sequoia. Short duration storage resources were then incrementally added to examine their effect on capacity need.[146] **Figure 69** shows the changes to 2030 capacity need for winter and summer using this method.

The results indicate that short duration storage resources are effective at addressing PGE's summer capacity needs and inefficient at meeting PGE's winter capacity needs. The results clearly demonstrate the challenge of addressing winter adequacy with short duration storage resources under current system assumptions.[147] A 2030 winter capacity need of 123 MW persists after adding the Energy Only Preferred Portfolio and no additional storage resources.[148] This suggests that the 1800 MW of four-hour batteries in the Preferred Portfolio is required to resolve 123 MW of winter capacity need, a 6.8 percent ELCC. For comparison, the summer need

[145] Total value includes sum of nameplate for storage and energy resources associated with hybrids. Energy resources from hybrids were segmented and included in the base system with equivalent generation profiles. Additionally, the Energy Only Portfolio includes energy equivalent to the 123 MWa Non-Emitting Contract modeled as a hydro resource using parameters from recent hydro contracts.

[146] All incremental additions are modeled as 4-hour stand-alone energy resources with standard Sequoia assumptions, starting each simulated week fully charged. This assumption is consistent with how storage and hybrid resources are modeled in the above adequacy assessment. Additions were made in 100, 200, 400, 600, 800, 1000, 1400, 1800, and 2000 MW tranches then smoothed and interpolated using the same methodology as in the 2033 CEP/IRP and 2023 CEP/IRP Update.

[147] The Energy Only Preferred Portfolio plus 1800 MW of storage resources results in a winter capacity need of 0 MW and 2.21 LOLH, compared against the Preferred Portfolio's winter capacity need of 0 MW and 2.25 LOLH as shown in **Table 32.** The modest difference in modeling results relates to small differences in assumed charging behavior between hybrid and standalone storage resources and other portfolio modeling simplifications. Interpolation between the 1400 MW tranche an 1800 MW tranche of storage additions results in a curve suggesting approximately 1600 MW are required to achieve adequacy.

[148] As compared to the 978 MW and 886 MW capacity needs for summer and winter, respectively, prior to any additions from the Preferred Portfolio, **Section 3.4 Capacity need**.

remaining after energy additions is 213 MW. This need is resolved with an estimated 400 MW of storage additions, a 53 percent ELCC.

Figure 69. Capacity Need of Energy Only Portfolio and Cumulative 4-hour Storage Additions - 2030 Reference

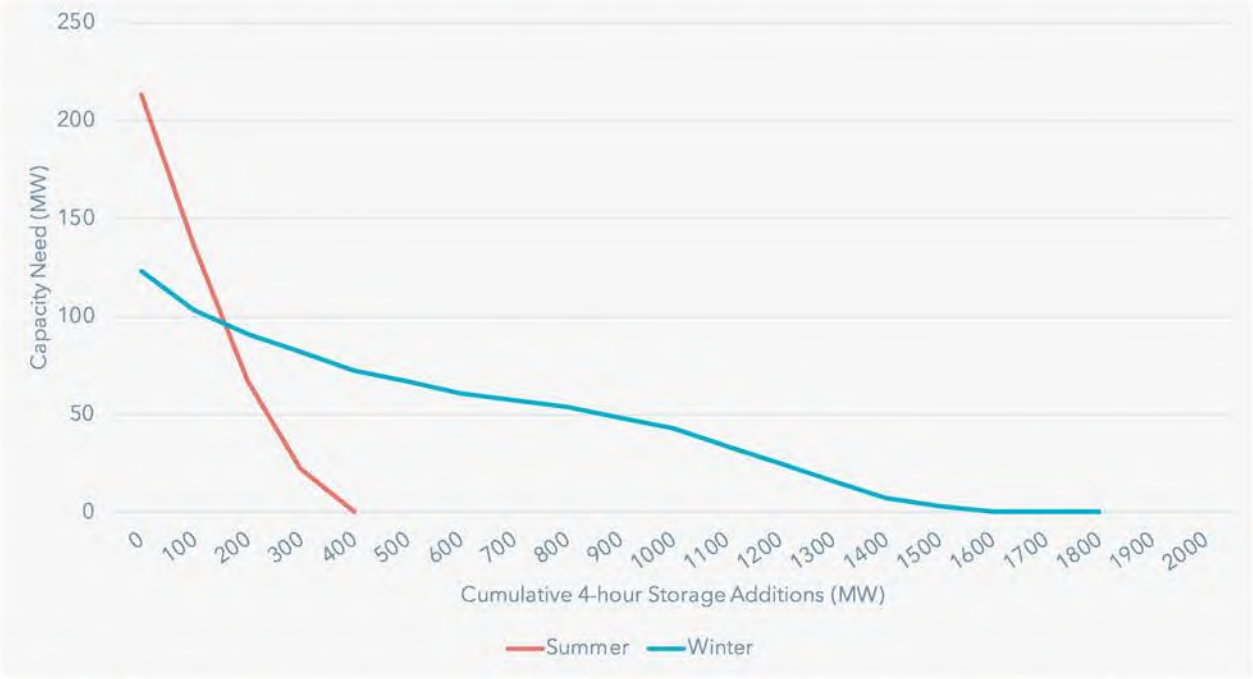
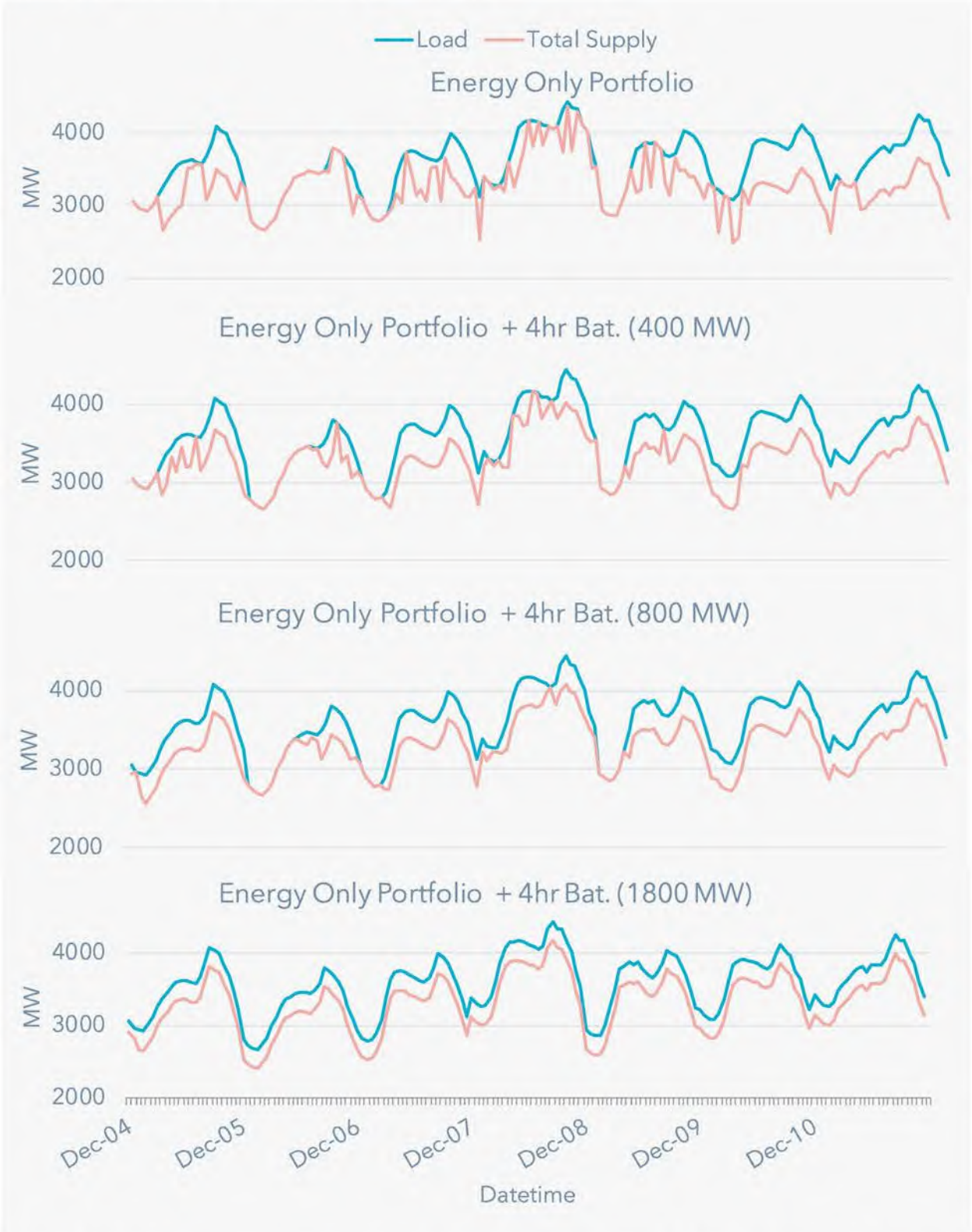


Figure 70 shows a Sequoia simulation of load and supply during a week in December 2030. This image highlights the challenge of trying to meet load in winter with short-duration storage resources. The first panel shows load and total supply in the base system with the Energy Only Portfolio, where gaps between total supply and load are unserved energy. As the quantity of storage increases the supply curve is shaped to reduce the largest hours of unserved energy. Due to insufficient energy, the optimal solution is to charge during periods of adequacy and lessen the size of unserved energy events in other hours, as is clear in Panel 4.[149] Panel 4 represents a tail event in the system, a week of energy shortfall where all 168 hours are short. Such a week has a 1 in 100,000 chance of occurring in an adequate system which includes the Preferred Portfolio. This inability of storage resources to resolve shortages when energy is short is representative of the declining marginal winter capacity curve shown in **Figure 69**.

[149] The objective function of Sequoia is to minimize the sum of the greatest hour of unserved energy of the week plus the average shortfall across the week.

Figure 70. December 2030 Weekly Adequacy Simulation



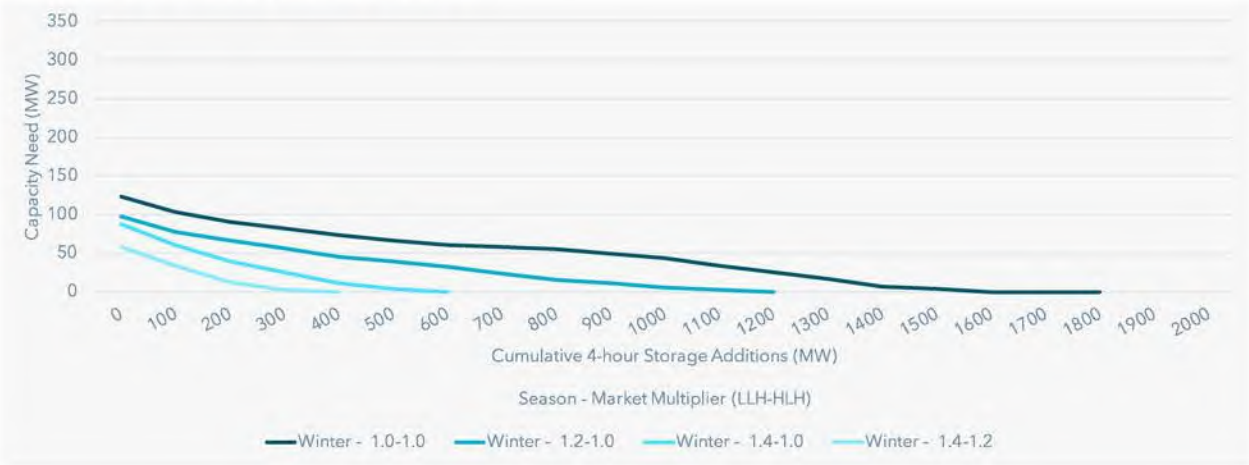
Previous regional resource adequacy studies have also reported on the challenges of meeting adequacy needs in the Pacific Northwest with short-duration storage. Energy and Environmental

Economics (E3) highlighted the steeply declining ELCC value of storage resources as a pattern that is particularly acute in the Pacific Northwest due to the quantity of hydro resources in the region.[150] This report concluded that firm capacity is an important component of a deeply decarbonized grid, and achieving decarbonization using only wind, solar, hydro and energy storage is impractical and prohibitively expensive. To compare the capacity value of dispatchable hydro resources against energy storage, the Company modeled the 2030 ELCC of the Non-Emitting Contract from the Preferred Portfolio based on parameters detailed in recent bilateral hydro agreements. The capacity value of this contract was estimated at 189 MW and when added to the system with the Energy Only Portfolio in 2030 resulted in ELCCs of 122 percent in summer and 115 percent ELCC in winter, as compared to 46 percent in summer and 22 percent in winter for 200 MW of 4-hour battery storage.

To test whether availability of energy is constraining the value of storage resources in winter, the same Energy Only Preferred Portfolio and incremental storage sensitivity analysis was conducted under various market availability assumptions. Adjustments were made by scaling Sequoia's market access assumptions for low-load hours (LLH) and heavy-load hours (HLH).[151] **Figure 71** shows the effect of this market sensitivity test on seasonal capacity need, where the market access multiplier represents the scalar for LLH and HLH, respectively. For example, in the 1.2-1.0 market access multiplier scenario an additional 20 percent (approximately 200 MW) is available during LLH and no change is assumed during HLH. In the 1.4-1.0 scenario, an additional 400 MW to the maximum availability in LLH results in winter adequacy at approximately 600 MW of incremental storage. This quantity of storage is equivalent to that included in the State RA Requirements Portfolio, 1200 MW less than the Preferred Portfolio.

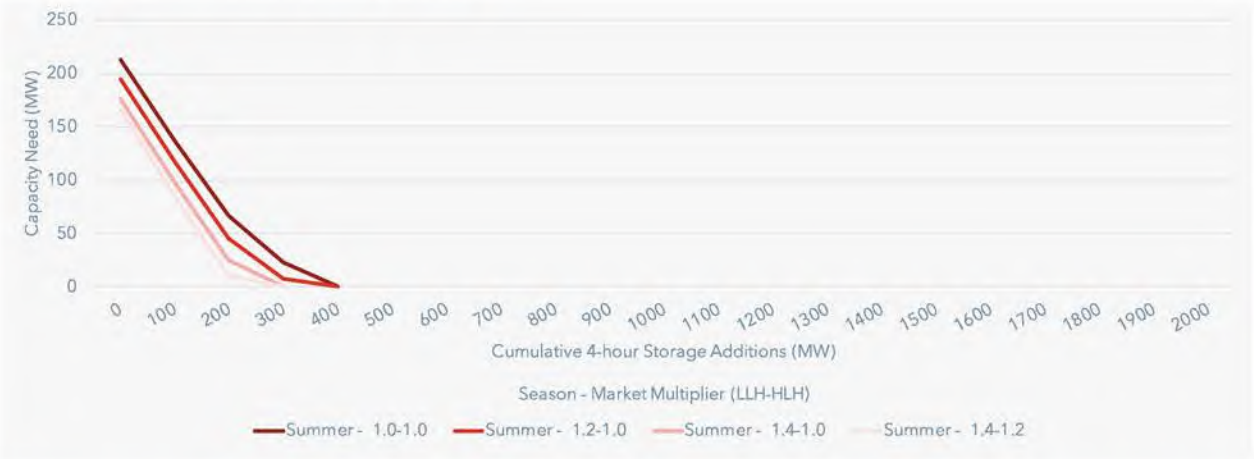
Figure 71. Capacity Need of Energy Only Portfolio with Incremental 4-hour Storage Additions and Variable Market Availability Assumptions - 2030 Reference

Panel A - Winter Capacity Need



[150] Energy and Environmental Economics. 2019. Resource Adequacy in the Pacific Northwest. San Francisco, CA.
[151] Sequoia's standard market assumptions vary by month, weekend/weekday, and hour (LLH/HLH) and are negatively correlated to load (i.e., greater load assumes less availability). In December, weekday values are limited to 999 MW and 150 MW for LLH and HLH, respectively. In August, values are limited to 999 MW and 0 MW for LLH and HLH, respectively.

Panel B – Summer Capacity Need



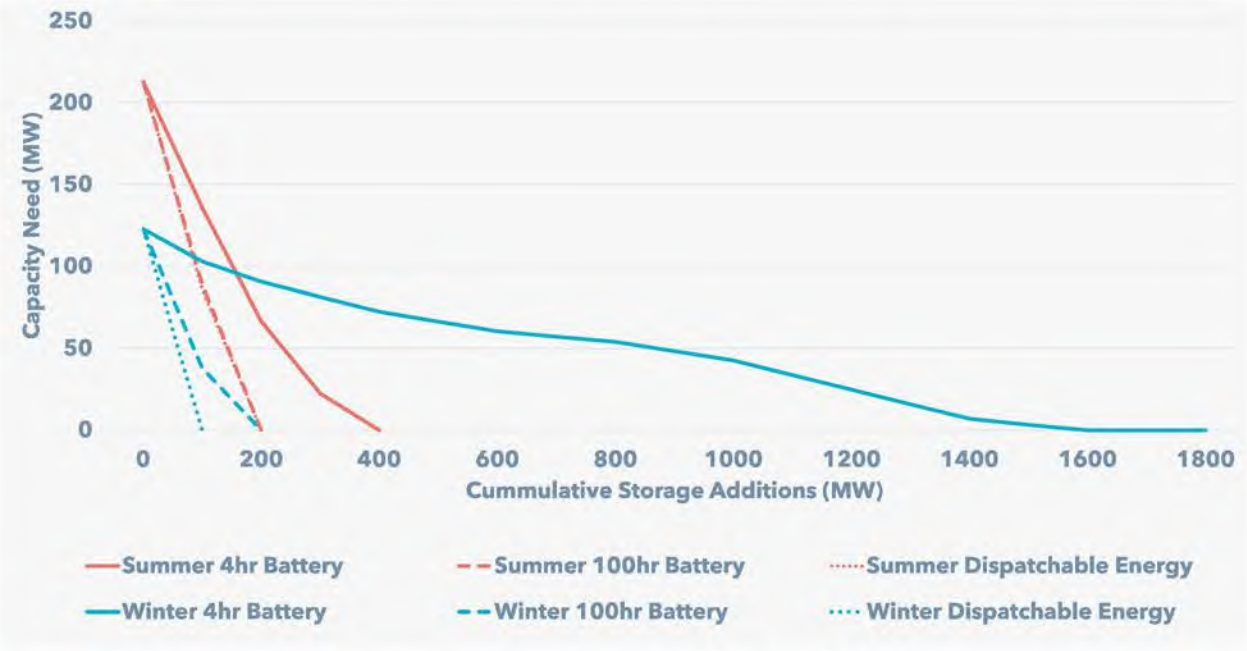
The above results highlight the sensitivity of the Preferred Portfolio to PGE's assumptions of access to regional markets. An estimated 66 percent of the 1800 MW of storage in the Preferred Portfolio is offset with approximately 400 MW of additional energy in LLH. Changing market access assumptions to arrive at a portfolio roughly equivalent to the State RA Requirement Portfolio reduces the NPVRR of resources by roughly $7 billion dollars across the planning horizon.[152] However, an Energy Only Portfolio with storage resources equivalent to the State RA Requirements portfolio is inadequate in winter 2030 as estimated in Sequoia. 60 MW of winter capacity need remain to achieve the 24-hours in 10 years metric. This capacity need equates to 3.73 LOLH, or 37 hours of unserved energy in 10 years for winter.

Finally, PGE estimated capacity contributions from emergent technologies as part of this analysis. These estimates are considered preliminary, and the Company intends to further refine them and EDAM market capacity contributions (see **Section 2.2.1 CAISO's Extended Day Ahead Market**) as part of the 2026 CEP/IRP. **Figure 72** compares capacity contributions of long-duration storage (LDS) and dispatchable energy technologies against those from 4-hour storage, as displayed in **Figure 69**.[153] This analysis suggests that approximately 200 MW of 100-hour storage and 100 MW of dispatchable energy provides effective capacity equivalent to 1800 MW of 4-hour batteries when added to the Energy Only Portfolio. Unlike 4-hour storage, the characteristics of these emergent technologies appear better suited to resolve the multi-hour reliability events characteristic to the winter season because of their ability to hold greater quantities of energy or generate energy on demand.

[152] Energy resources in the State RA Requirements Portfolio are roughly equivalent to those in the Preferred Portfolio. Value represents the difference between the NVPRR of the Preferred Portfolio and the State RA Requirements Portfolio presented in **Section 6.2 Preferred Portfolio** and **Section 6.3.5 State RA requirements**.

[153] LDS is modeled as a 100-hour battery with 35% round-trip efficiency, while dispatchable energy is modeled as perfect capacity. Long-duration storage is assumed to start each dispatch period fully charged, just as short-duration storage. Improved representation of the operational availability of LDS is suggested for the 2026 CEP/IRP.

Figure 72. Capacity Need of Energy Only Portfolio and Emergent Technology Additions - 2030 Reference



The results from this energy sensitivity analysis show that ELCCs for winter storage do not improve with additional energy availability and short-duration storage remains an inefficient marginal resource for meeting winter adequacy needs. Short-duration resources are inefficient primarily due to the length of constraining reliability events. This conclusion motivates **Section 6.7 Net cost of capacity resources**, where the Company represents the cost of marginal resource with a value that captures the capacity and energy costs required to ensure adequacy.

Further, this analysis provides insight into four considerations PGE intends to investigate in the 2026 CEP/IRP with respect to future capacity needs: (1) continue to rely on short-duration storage as the marginal resource, (2) evaluate the role of additional energy from expanded market access, (3) evaluate the role of an expanded regional sharing mechanism as part of the State Resource Adequacy requirements, and (4) review the viability of emergent technologies as the marginal resource. PGE expects it necessary to identify different long-term marginal capacity resources better suited to provide the energy and capacity necessary to meet ongoing winter adequacy challenges, such as long-duration storage, hydrogen storage resources, advanced geothermal, nuclear generation, carbon capture utilization and storage, and long-distance transmission access to geographically diverse trading hubs, such as the North Plains Connector.

6.3 Portfolio sensitivities

This section describes, and presents results for, the multiple sensitivities that are conducted on the Preferred Portfolio. Topics explored through these sensitivities include the quantity of emitting energy retained by PGE to serve retail load, large industrial customer growth, resource adequacy planning assumptions and the availability of non-emitting market purchases for hourly emissions accounting. Except where otherwise specified, PGE held the assumptions for each

sensitivity constant with those of the Preferred Portfolio in order to isolate the impacts to the topic of interest. Select results are presented for each scenario to highlight the findings of interest.

6.3.1 Reliability needs only

The 'Reliability Needs Only' scenario demonstrates how capacity and energy needs driven by load growth and portfolio composition changes. In this scenario, HB 2021 GHG emissions targets are not enforced. The quantity of thermal energy retained from PGE's existing fleet of resources to serve retail load is determined by recent historical plant operations. Additionally, thermal resources continue to provide capacity beyond 2039, unlike the Preferred Portfolio, in which the capacity from thermals must be replaced with non-emitting sources in 2040. Although not constrained to HB 2021 emissions reductions, the 'Reliability Needs Only' scenario is compliant with RPS requirements. As in all other portfolios analyzed in the Update, this portfolio does not contemplate the addition of new natural gas resources to PGE's portfolio.

Resource additions for the 'Reliability Needs Only' scenario are shown in **Figure 73**. Optimized resource additions through 2030 include 1262 MW of wind, 1189 MW of solar, 1745 MW of storage, 83 MW of non-cost-effective EE and DERs, 155 MW of CBREs, and 9 MW of non-emitting contracts. Total resource additions in 2030 are 95 percent of those in the Preferred Portfolio. The substantial incremental resource additions by 2030 without reducing thermals suggests resource adequacy, including the need to serve growing load in a reliable manner, is a main driver of PGE's resource needs.

Results differ more substantially from the Preferred Portfolio later in the analysis time-horizon when the ability to retain thermals for capacity impacts resource additions. By 2040, the resource additions of the "Reliability Needs Only' scenario are only 53 percent of those in the Preferred Portfolio. Driven largely by these later-year differences, the cost and risk of the 'Reliability Needs Only' scenario, shown in **Figure 74**, are substantially lower than the Preferred Portfolio. 20-year portfolio NPVRR for the 'Reliability Needs Only' scenario are $4,970 million lower than the Preferred Portfolio.

Figure 73. Resource Additions for Reliability Needs Only Scenario (MW)

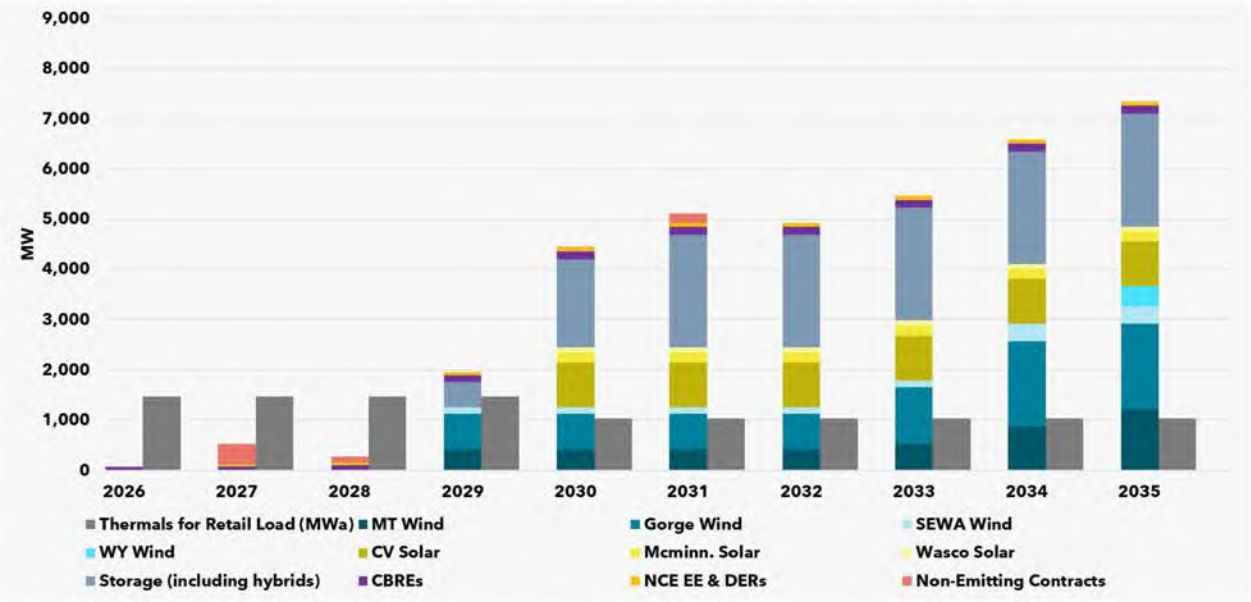
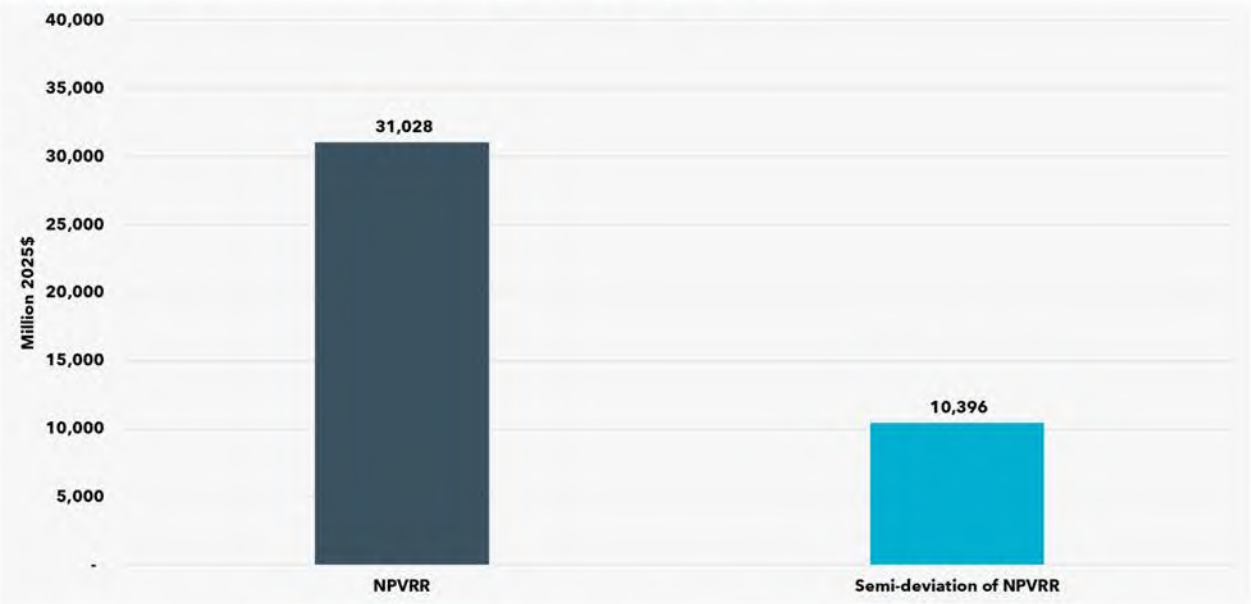


Figure 74. Cost and Risk of Reliability Needs Only Scenario



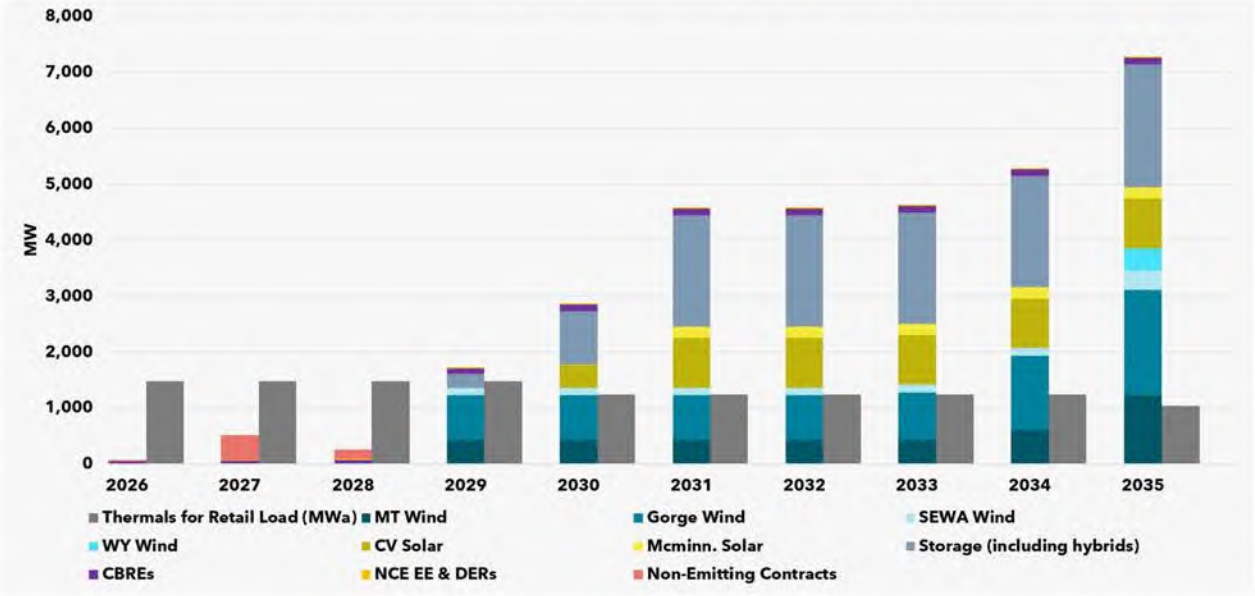
6.3.2 Further Reliability need sensitivities

The scenarios presented in this section expand upon the 'Reliability Needs Only' scenario by considering how needs are reduced assuming 1) that PGE extends a 250 MW contract for dispatchable emitting energy and 2) PGE extends a 250 MW contract for dispatchable emitting energy in addition to a 250 MW non-emitting hydro contract. These scenarios are named the 'Dispatchable Emitting Contract Scenario' and the 'Dispatchable Emitting and Hydro Contracts Scenario'. Both contract extensions are assumed to provide both energy and capacity from 2030 through 2034. Aside from the contract extension assumptions, these scenarios rely on identical

assumptions to the 'Reliability Needs Only' scenario. In contrast to the small impact on needs found when comparing the 'Reliability Needs Only' scenario, with its' reduced energy needs, to the Preferred Portfolio, the addition of capacity and energy from contract extensions in these scenarios produces substantial reductions in 2030 resource needs, as illustrated in the results below.

Portfolio resource additions for the 'Dispatchable Emitting Contract Scenario' shown in **Figure 75**. Additional quantities of emitting energy can be seen as taller gray bars in 2030 – 2034. Through 2030, the portfolio adds 1362 MW of wind, 415 MW of solar, 952 MW of storage, 24 MW of NCE EE and DERs, and 119 MW of CBREs. Total resource additions are 2872 MW through 2030, which is 1571 MW, or 35 percent, lower than in the 'Reliability Needs Only' Scenario. The decrease in resources is driven largely by decreases in the quantity of solar and storage, with CBRE's, NCE EE, and NCE DERs are also reduced.

Figure 75. Resource Additions for Dispatchable Emitting Contract Scenario

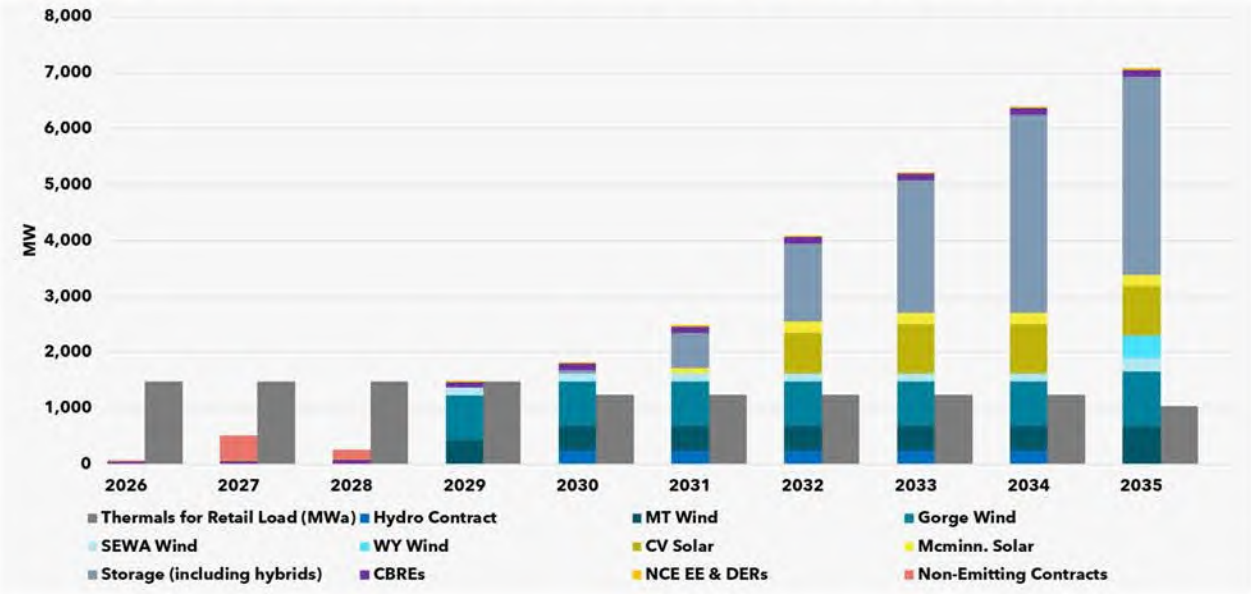


Portfolio resource additions for the 'Dispatchable Emitting and Hydro Contracts Scenario' shown in **Figure 76**. Through 2030, the portfolio adds 1362 MW of wind, 64 MW of storage, 24 MW of NCE EE and DERs, and 119 MW of CBREs. Total resource additions are 1569 MW through 2030, which is 2874 MW, or 65 percent, lower than in the 'Reliability Needs Only' Scenario. Consistent with the results of the previous scenario, the decrease in resources is driven largely by decreases in the quantity of solar and storage.

Notably, in the 'Dispatchable Emitting and Hydro Contracts Scenario' the need for transmission options is reduced, with the needs reduced enough during the 2030 – 2034 period of contract extensions that the 3000 MW Bethel-Round Butte transmission upgrade (BRB) is foregone when it becomes available in 2032. The impact of this outcome produces an initially unintuitive result when comparing the resource additions of the two contract extension scenarios in 2033 - 2034

reveals. Comparison of **Figure 75** and **Figure 76** reveal larger 2033 and 2034 resource additions in the 'Dispatchable Emitting and Hydro Contracts Scenario', which has 500 MW of contract extensions than the 'Dispatchable Emitting Contract Scenario', which has 250 MW of contract extension. Instead of investing in BRB, the 'Dispatchable Emitting and Hydro Contracts Scenario' lowers costs by relying on additional quantities of storage to meet needs in these years and delaying the addition of any transmission options until 2035.

Figure 76. Resource Additions for Dispatchable Emitting and Hydro Contracts Scenario



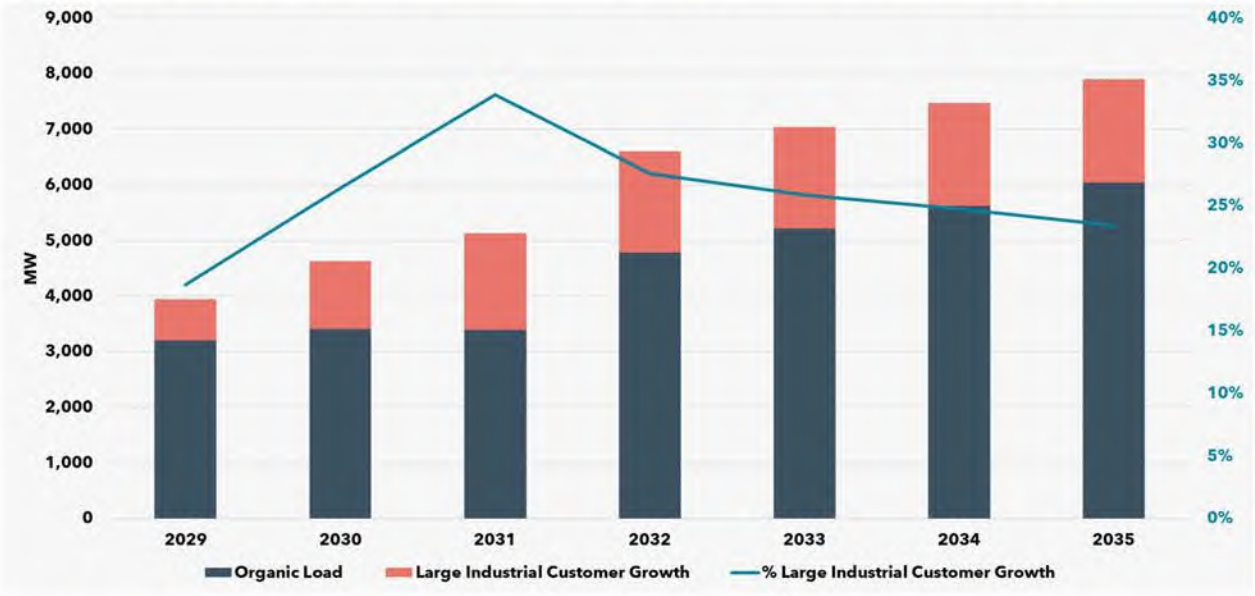
6.3.3 Large industrial customer growth

As described in **Section 2.4 Industrial load growth**, substantial electricity demand from large industrial customers is projected in the PNW in coming decades and will have implications for utility planning. PGE is taking steps to mitigate the risk of inequitable customer cost impacts associated with large industrial load growth, including through its filings in UE 430 and UM 2377, in which PGE has proposed a change to its tariff regarding cost allocation amongst customer classes. In addition, the Oregon legislature is considering law that would place data centers into a specific customer class. The Update analysis is illustrative of how new resource costs are driven by all large and growing industrial customers. There remain important differences in methodology and purpose between the IRP Update analysis and methodology that may result from UM 2377 which may limit the applicability of these results which should be considered illustrative only.

As an initial exploration of the impacts of this projected growth on PGE's planning, an analysis was conducted to identify what the quantity of resource additions in PGE's Preferred Portfolio are associated with meeting the needs created by the growth of large industrial customers. To do so, PGE created a load forecast sensitivity that excludes large industrial customer growth. This forecast and the methodology used to develop it are described in detail in **Section 3.1.3 Load forecasts – excluding large customer** . The load that remains to be served after removing the

impact of large industrial customer growth is referred to here as 'organic load'. Using this load forecast, a scenario was created that produced a portfolio of resource additions that provides sufficient energy and capacity needs to meet organic load growth and is compliant with HB 2021. The resulting capacity need for the 2030 reference case is estimated at 497 MW and 473 MW for summer and winter, respectively, roughly 50 percent of the estimated capacity need for the Preferred Portfolio. The quantity of resources associated with serving large industrial customer growth can be estimated by taking the difference in the resource buildout of the Preferred Portfolio and the 'No Large Industrial Customer Growth' scenario, which adds resources to meet organic load only. **Figure 77** shows the total cumulative resource additions in each year for the Preferred Portfolio and the 'No Large Industrial Customer Growth' scenario and shows that by 2030, about 26 percent resource additions can be attributed to growth in large industrial customer load. Resource additions associated with large industrial customer growth reach as high as nearly 34 percent in 2031.

Figure 77. Cumulative Resource Additions for Large Industrial Customer Growth



6.3.4 Market scenarios

PGE developed three market scenarios to analyze uncertainties in the potential availability of low- and non-emitting power for purchase. These scenarios vary assumptions in PGE's IGHG model which impact the quantity of emitting energy that PGE is ultimately able to retain to serve retail load. Compliance with HB 2021 is assumed for each alternative market scenario. The three market scenarios are described in **Table 33**.

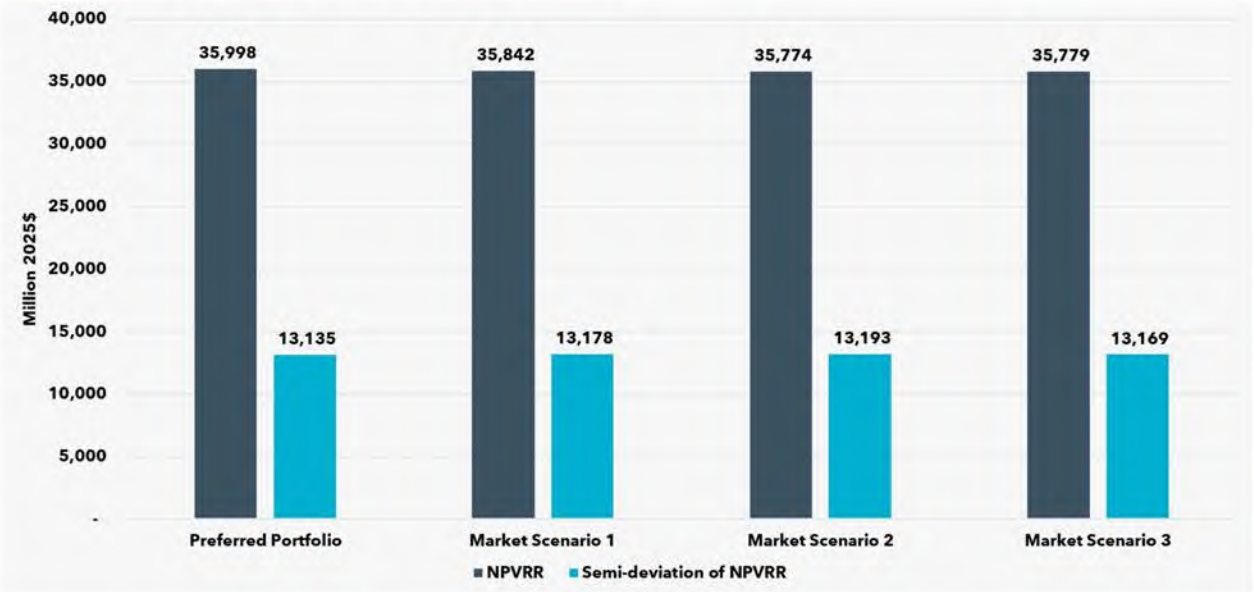
Table 33. Market Scenarios

Scenario	Description
Market Scenario 1: Specify More Power Purchases	Specify 50% of the assumed unspecified market purchases (informed by historical data) serving retail load in the IGHG

Scenario	Description
	model as non-emitting with the remaining 50% assigned the market unspecified emissions rate.
Market Scenario 2: Extend Low-Emitting Existing Purchases	Extend known low-emitting short-term specified purchases that would otherwise expire in the IGHG model.
Market Scenario 3: Lower Emission Rate	Reduce the emissions rate of unspecified market purchases in the IGHG model by 30%.

Because the assumptions in the market scenarios allow PGE to retain more emitting energy and thus reduce the energy need, resource additions are lower than in the Preferred Portfolio. However, because capacity need is unchanged, the impacts on resource buildouts and portfolio cost and risk are modest. Portfolio cost and risk metrics for the market scenarios are shown in **Figure 78**. Relative to the Preferred Portfolio, Market Scenario 1 lowers portfolio cost by $156 million, while Market Scenarios 2 and 3 produce costs $224 million and $219 million lower than the Preferred Portfolio, over the 20-year analysis time-horizon.

Figure 78. Cost and Risk of Market Scenarios



6.3.5 State RA requirements

The 'State RA Requirements' scenario models PGE's resource adequacy needs using methods from the WRAP instead of using the PGE resource adequacy methods that are standard in the Preferred Portfolio and all other scenarios. The alternative methodology used for this scenario impacts capacity need and proxy resource ELCCs, as described in **Appendix I Inputs for state RA requirements portfolio**. Because of the assumed sharing of resources by regional entities, the WRAP methodology generally produces a lower estimated capacity need than PGE's standard IRP methods. As a result, the resource additions in the 'State RA Requirements' scenario are substantially lower than in the Preferred Portfolio and portfolio cost is $6,817 million lower

over the planning horizon. Resource additions for the 'State RA Requirements' scenario are shown in **Figure 79**, and cost and risk metrics are shown in **Figure 80**.

Figure 79. Resource Additions in State RA Requirements Scenario (MW)

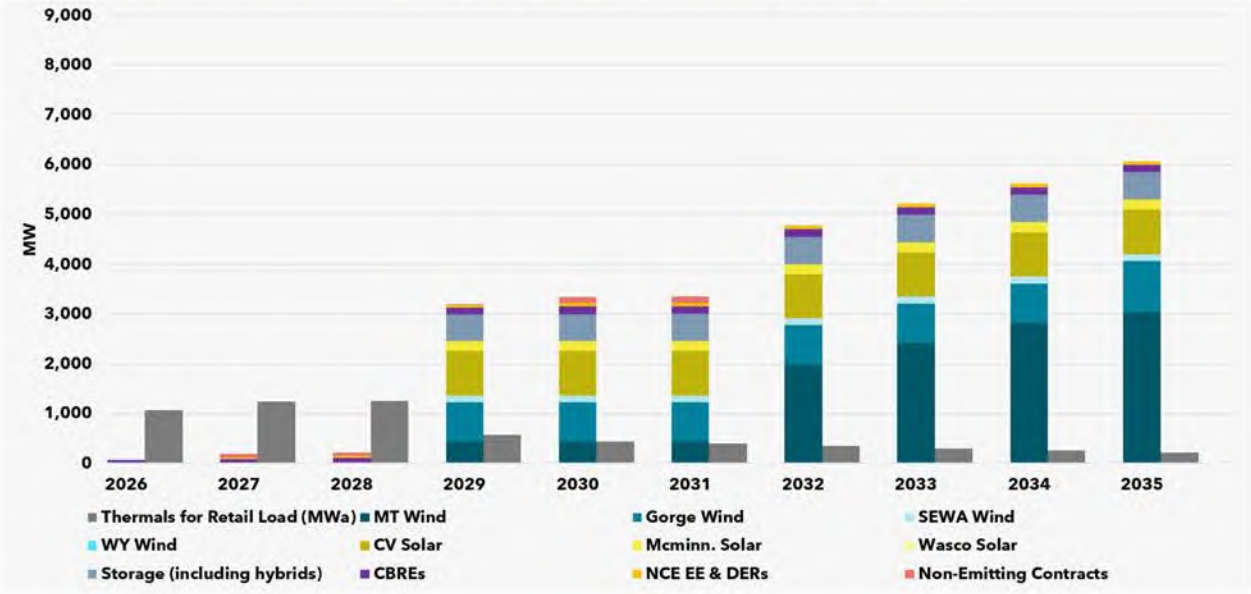
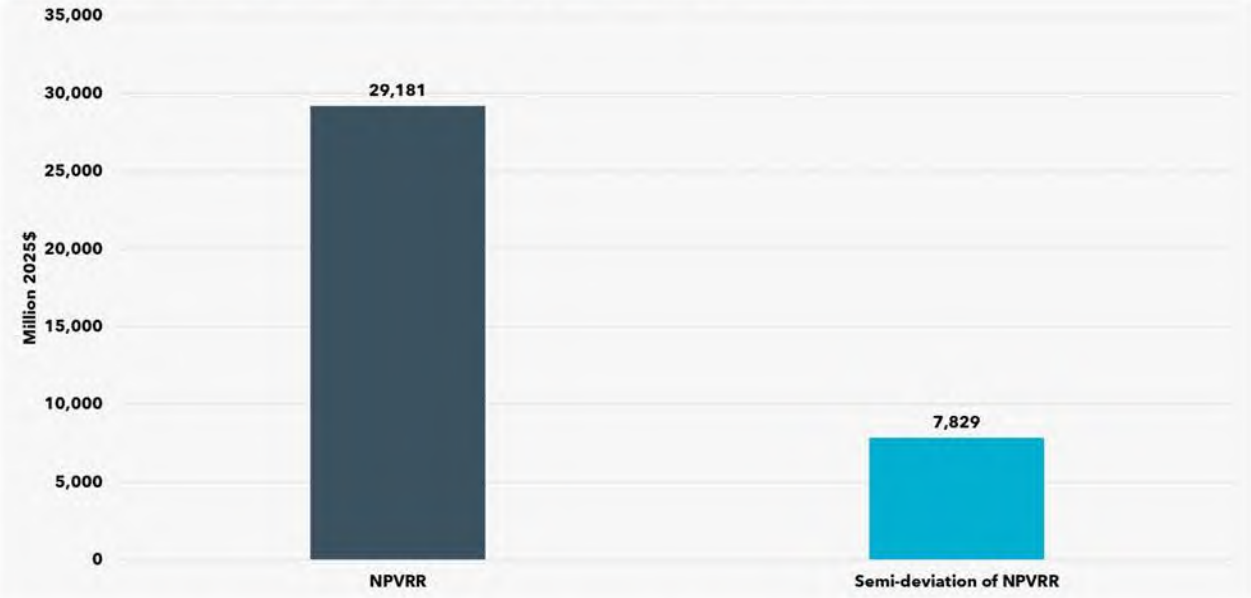


Figure 80. Cost and Risk of State RA Requirements Scenario



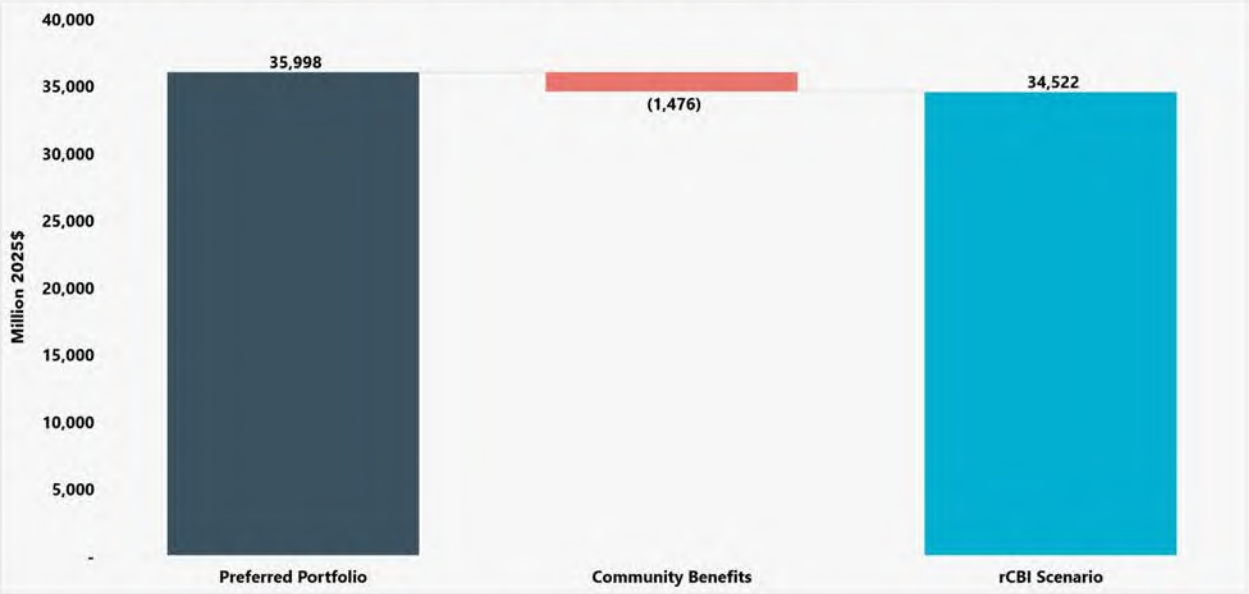
6.3.6 Resource Community Benefits Indicator (rCBI)

The 'rCBI' scenario applies reductions in fixed costs to certain CBRE, NCE DR, and NCE EE resources to reflect the societal value of community benefits associated with these resources, as described in **Section 5.5 Community benefits indicators (CBIs)**. Because the majority of NCE EE and DR, and the entirety of CBRE resources available, are added in the Preferred Portfolio,

differences in resource buildout between the 'rCBI' scenario and the Preferred Portfolio are minimal. The reduced fixed costs did result in the selection of an additional 2 MW of NCE DR resources.

The lower costs associated with these resources lowered portfolio NPVRR by $1,476 million compared to the Preferred Portfolio (**Figure 81**). This reduction in NPVRR represents the value of localized community benefits provided by the resources in the portfolio. The $1,476 million in community benefits reflects the societal benefits provided by the resources in the portfolio and does not represent a decrease in the monetary cost of the portfolio or suggest that the 'rCBI' portfolio would result in lower customer bills than the Preferred Portfolio.

Figure 81. NPVRR of Preferred Portfolio and rCBI Scenario



6.3.7 Absence of non-emitting market

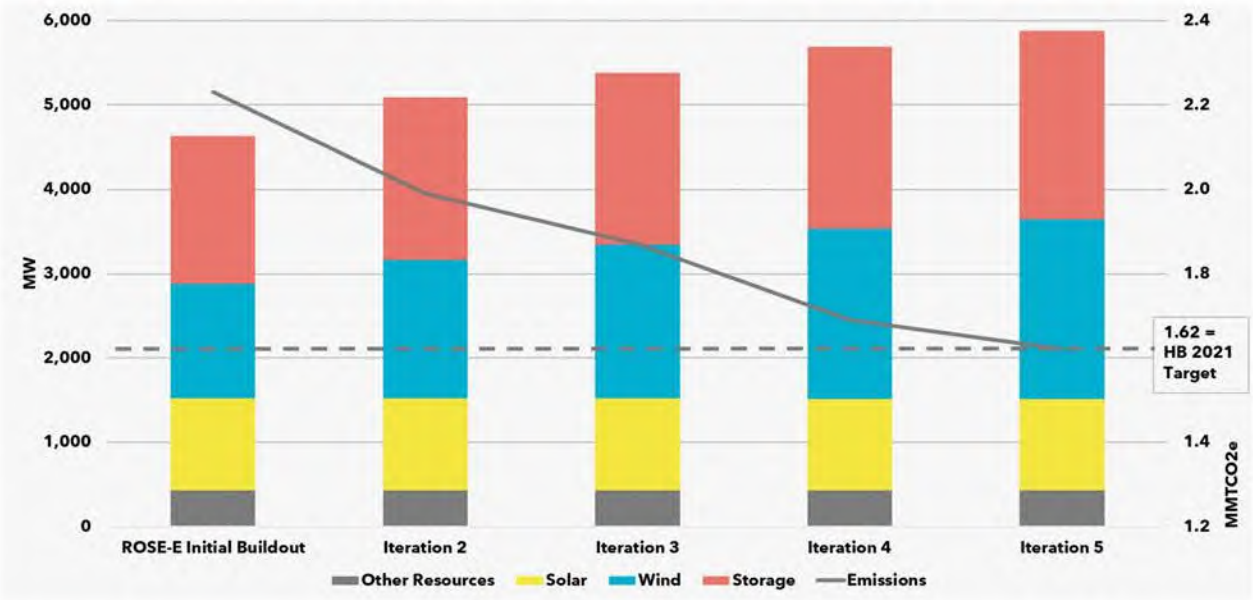
The 'Absence of Non-Emitting Market' scenario contemplates the quantity of resource additions that would be necessary to meet HB 2021 emissions targets using hourly energy accounting if PGE didn't have access to the non-emitting market energy that is available in the analysis reported in **Section 6.2.2 Hourly energy and emissions accounting results**. A detailed description of the iteration method is provided in **Appendix D Hourly emissions methodology**. In brief, the question is answered using the following approach:

1. ROSE-E determines the resources required to meet resource needs based on monthly energy sufficiency.
2. The modified PZM estimates what hours in the year would PGE be short (and by how much) under average conditions.
3. An outboard workbook creates a new energy constraint to be met and resource options are assigned a weighted capacity factor that encourages the addition of resources that are most useful in meeting that need. The new constraint is fed back into step 1 until a portfolio that meets all hourly needs is produced.

Because transmission constraints would make it impossible to add sufficient resources to meet the hourly emissions requirements in 2030, the resource additions in iterations subsequent to the initial ROSE-E buildout are not subject to transmission constraints.

Over the course of five iterations between ROSE-E and the modified PZM, incremental additions of renewable and storage resources are added until the portfolio achieves emissions of 1.62 MMTCO2e when evaluated at an hourly time-step (**Figure 82**). When the portfolio achieves emissions targets, the quantity of resource additions has increased by 1249 MW, from 4629 MW in the initial ROSE-E buildout to 5881 MW in the fifth iteration. This 21 percent increase in the quantity of resources in the portfolio illustrates that for PGE to decarbonize in isolation, substantial additional resources would be required that may exacerbate procurement challenges and cost pressure. The findings underscore the importance of access to market opportunities to purchase non-emitting energy from entities within the region.

Figure 82. Resource Addition Iterations in Absence of Non-Emitting Market Scenario



6.4 Small scale renewables plan

As required by ORS 469A.210, PGE has a 10 percent small-scale renewable requirement, requiring that 10 percent of electrical generating capacity come from renewable resources smaller than 20 MW or qualifying biomass generators starting in 2030.[154] Per Staff Recommendation #5, approved via LC 80 Order 24-096, PGE has included a SSR compliance analysis as part of this Update. This compliance analysis provided in this section assesses the forecast SSR need, resource contributions, costs, and acquisition/compliance actions. This will include results from portfolio analysis using a SSR proxy resource. It will also include a discussion of how PGE plans to acquire the needed resources to achieve compliance and a discussion on the current status and potential future status of customer sited resources for SSR compliance.

[154] Oregon ORS 469A.210 can be found at https://www.oregonlegislature.gov/bills_laws/ors/ors469a.html.

6.4.1 SSR needs assessment

The SSR need is a function of the nameplate capacity of resource in PGE's baseline portfolio and new resources added through capacity expansion modeling. In the Preferred Portfolio, PGE forecasts an aggregate SSR need of 769 MW in 2030, growing to 1292 MW by 2040 (**Table 34**).

Table 34. Total SSR Compliance Requirement by Year

Year	Preferred Portfolio
<2030	No min. requirement
2030	738 MW
2035	991 MW
2040	1314 MW

6.4.2 Contributions from baseline resource acquisition

Several ongoing resource acquisition pathways contribute to SSR development, including the Oregon Community Solar Program projects, QF development, and CBRE acquisition:

- CSP capacity in 2030: 93 MW
- QF capacity <20 MW under contract to PGE in 2030: 260 MW
- CBRE acquisition forecast for 2030: 155 MW
- Other PGE owned or contracted SSR-eligible projects modeled in 2030 portfolio: up to 51 MW

Per OPUC Order 21-464, net metered (NEM) renewables do not contribute to SSR compliance (or to PGE's aggregate electrical capacity). However, the role of net metered solar in PGE's planning has continued to evolve since 2021 as interconnected NEM solar more than doubled in three years. Improvements in inverter capabilities, increasingly common storage pairing, and advancement of grid planning and management as discussed in Distribution System Plans and PGE's Virtual Power Plant activities all have contributed to the value of solar to PGE's system. PGE's SSR compliance assessment considers NEM solar as a sensitivity. Customer solar deployment by 2030 is forecast to be 675 MW (see **Section 5.2.1.1 Distributed solar (PV)**).

6.4.3 Remaining SSR need

Table 35 summarizes PGE's 2030 SSR compliance position, with and without contributions of NEM. With NEM ineligible to contribute to compliance, PGE's forecasted incremental compliance requirement in 2030 is 179 MW of SSR resources. With all NEM solar considered as an eligible resource there is no incremental compliance need in 2030 (in this case, the first year in which an incremental need arises is 2036).

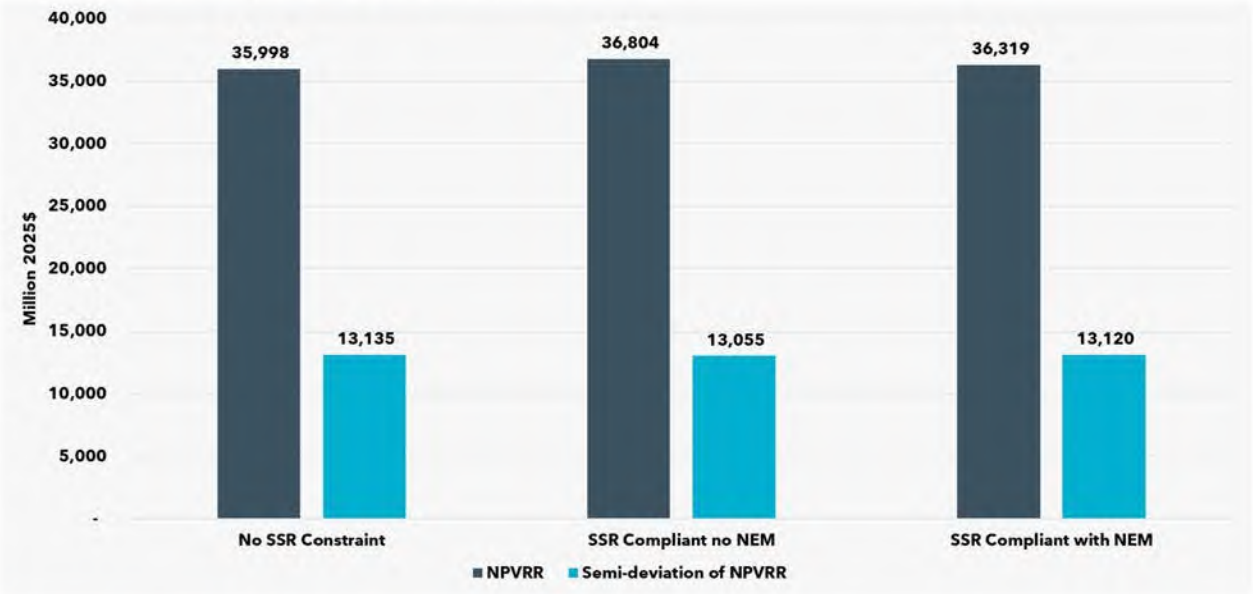
Table 35. SSR Compliance Position, 2030

Compliance Position	All NEM Remains Ineligible	All Customer Sited Eligible
2030 Compliance Need	738 MW	806 MW
Baseline Resource Contribution	560 MW	560 MW
Customer-Sited Contribution	0 MW	675 MW
Incremental Compliance Requirement	179 MW	0 MW

6.4.4 SSR compliance cost assessment

As discussed in **Section 5.4 SSR resource**, PGE used a modeling assumption that SSR resources cost eight percent more and have identical resource characteristics to utility-scale renewables. In order to assess the cost impacts of complying with SSR requirements in every year of the portfolio analysis time-horizon beginning in 2030, two portfolios were constructed. The first portfolio assumes that NEM is not eligible to contribute to compliance ('SSR Compliance No NEM'), and the second assumes that NEM is eligible ('SSR Compliance NEM'). Pairing of NEM solar with storage can increase the value of NEM resources and could plausibly be a consideration in future assessment of SSR eligibility; however, the 'SSR Compliance NEM' scenario does not incorporate any assumptions regarding storage addition. The costs of these portfolios, along with a portfolio that does not enforce SSR compliance, are shown in **Figure 83.** The cost of compliance in each of the two SSR scenarios can be illustrated by comparing the cost of these portfolios against that of the 'No SSR Constraint' portfolio. Results show that over the full analysis time-horizon, procurement of sufficient volumes of SSR resources increases net present portfolio costs by $806 million when NEM is not eligible and $321 million when NEM is eligible (due to costs incurred for compliance after 2036).

Figure 83. Cost Impacts of SSR Compliance



6.4.5 SSR acquisition strategy

As shown in **Figure 83**, significant customer benefit can be realized by reassessing the SSR eligibility of NEM capacity. This change would be fully consistent with Oregon statute as most recently revisited in HB 2021 and require only a Commission order, with no changes to administrative rules. As described in PGE's recent 2024 Distribution System Plan, PGE also is prioritizing deployment of a virtual power plant in which customer resources are harnessed for system benefit, akin to traditional supply-side resources. PGE looks forward to further progress on this topic as a key component of the SSR acquisition strategy.

In addition, PGE is pursuing the following resource acquisition actions, as discussed in the Action Plan:

- CBRE Acquisition
- All-Source Energy and Capacity procurement, in which PGE encourages offers from SSRs

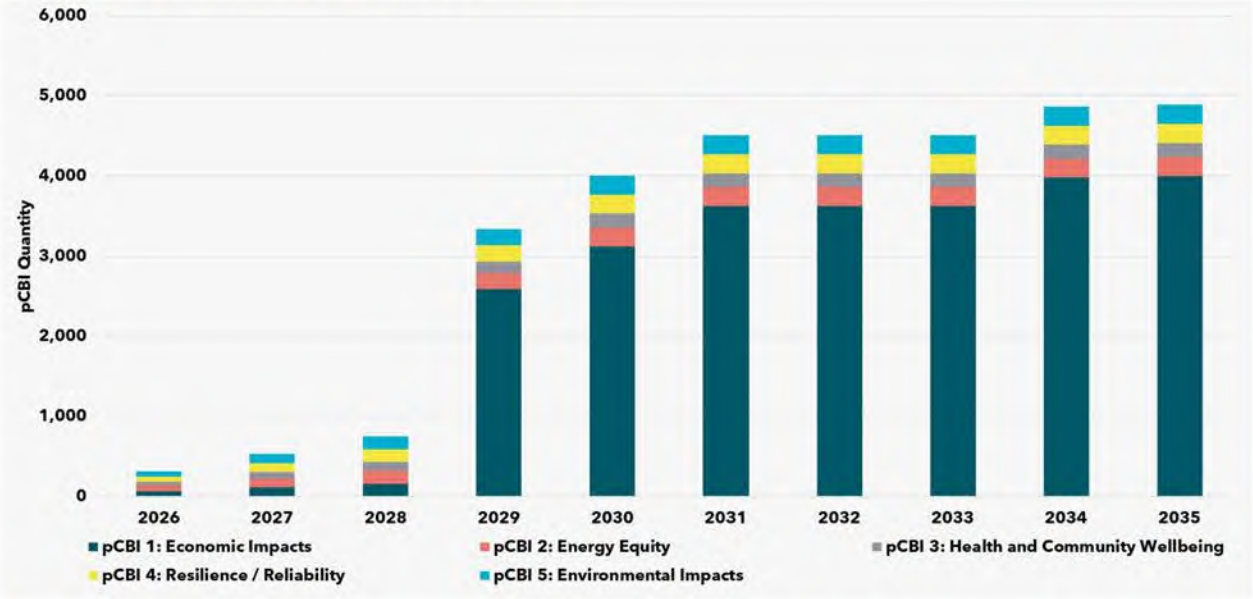
PGE believes incremental SSR procurement should only be pursued to the extent SSRs provide unique community benefits aligned with the CBRE acquisition pathway.

6.5 Portfolio CBIs

The cumulative quantity of each of the five pCBI scoring metrics through 2035 for the Preferred Portfolio are shown in **Figure 84**. A large increase in pCBIs generated can be seen in 2029, driven by the addition of substantial quantities of renewable resources, which generate economic community benefits (pCBI 1) when sited in OR. pCBIs 2-5 are generated by NCE EE and DERs and CBREs only and their quantities can be seen to increase through 2030 as additions of these resources are made to the portfolio. Because NCE EE and DERs and CBREs resources are not available for addition beyond 2030, the quantity of pCBIs 2-5 generated by the portfolio

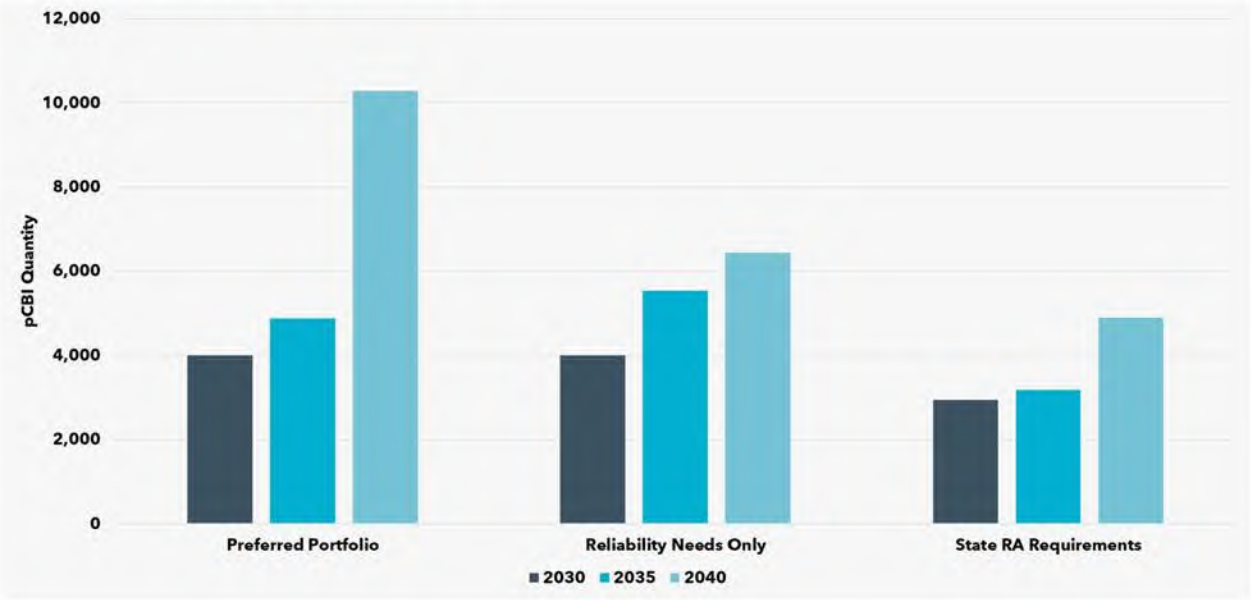
do not increase after 2030. Because of their very similar resource buildouts, the pCBIs generated by the 'rCBI' and three 'Market' scenarios are nearly identical to that of the Preferred Portfolio.

Figure 84. pCBIs of the Preferred Portfolio



Because pCBIs are unitless measures of community benefit, they are most useful in comparing the provision of benefits across alternative scenarios than as an absolute measure of community benefits. The total pCBI quantities of the Preferred Portfolio, and 'Reliability Needs Only' and 'State RA Requirements' scenarios are shown for 2030, 2035, and 2040 in **Figure 85**. Because the Preferred Portfolio has larger quantities of renewable resource additions, it generates more pCBIs than the 'Reliability Needs Only' and 'State RA Requirements' scenarios throughout the study period. In 2030 however, the 'Reliability Needs Only' portfolio generates more pCBIs than the Preferred Portfolio because it has a larger quantity OR renewables, which provide economic impact benefits (pCBI 1) than the Preferred Portfolio which relies more heavily on MT wind (which does not provide economic impact benefits due to it's out of state location). Intuitively, because larger quantities of resource additions generate more pCBIs, more expensive scenarios tend to generate more pCBIs.

Figure 85. Total pCBI Comparison

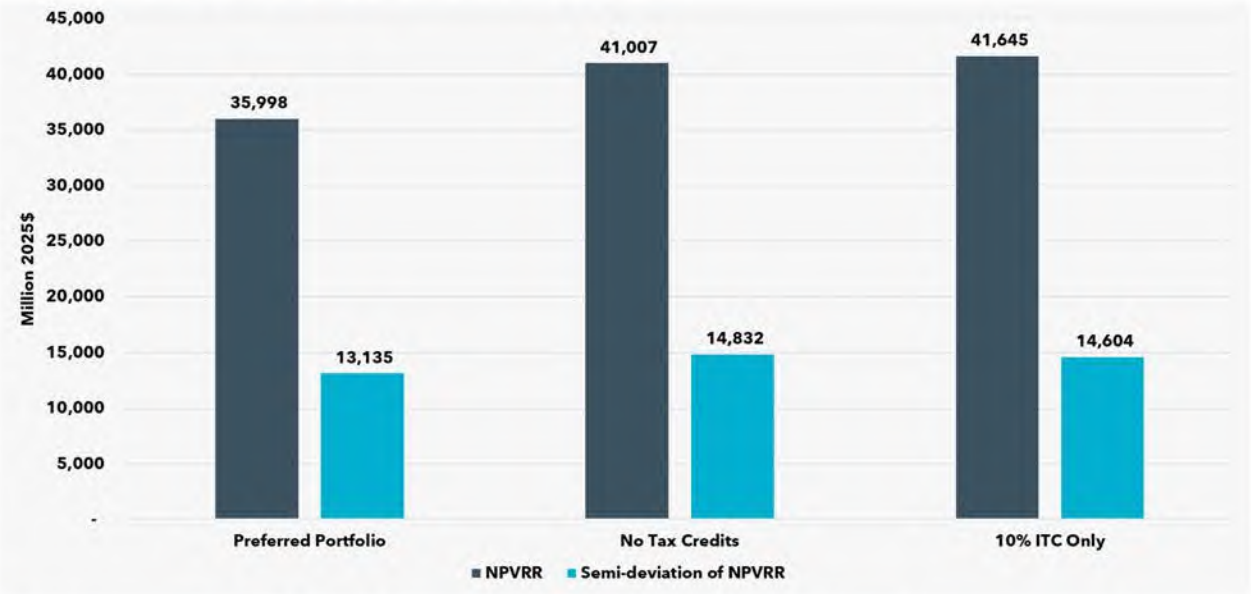


6.6 Federal tax credit availability scenarios

As noted in **Section 5.1.3 Tax credit sensitivities**, PGE's baseline resource cost assumptions assume the same tax credit environment for generation and energy storage resources as described in PGE's 2023 CEP/IRP. To help understand the potential impact on portfolio outcomes of changes to this set of assumptions, two sensitivities are considered: '10 percent ITC Only' and 'No Tax Credits'. In both scenarios, the costs of certain resources are increased relative to baseline assumptions. The impacts on resource costs of the change in assumptions in each of these scenarios are described **Section 5.1.3 Tax credit sensitivities.** The impact on portfolio composition and cost are explored through portfolio sensitivities in this section.

Both tax credit availability scenarios are modeled with identical assumptions to the Preferred Portfolio in every respect except for the changes to resource costs. The impact on portfolio costs and risk over the 20-year planning horizon in these two scenarios is shown in **Figure 86**. Intuitively, because resources are more expensive, portfolio NPVRR of each tax credit scenario is larger than the Preferred Portfolio. Relative to the Preferred Portfolio, NPVRR is $5,647 million larger in the '10 percent ITC Only' scenario and $5,009 million larger in the 'No Tax Credits' scenario. Reduction or removal of federal tax credits also increases the risk of costly outcomes outside of the Reference Case future, with increased semi-deviation of NPVRR across the 351 futures analyzed relative to the Preferred Portfolio.

Figure 86. Cost and risk of tax availability scenarios



Resource additions of the '10 percent ITC Only' and 'No Tax Credits' scenarios are shown in **Figure 87** and **Figure 88**, respectively. Portfolio resource buildouts of the scenarios are nearly identical to the Preferred Portfolio prior to 2032, with resource additions being driven by transmission constraints and the quantity of transmission available to the individual transmission zones. After 2031, the most notable changes associated with the re-optimized resource selection in both scenarios is a substitution of additional MT wind for some of the SE Washington wind in the portfolio. This effect is driven by the fact that a similar absolute increase in costs for both proxy resources produces a smaller relative increase in the cost of MT wind because it is more expensive, making MT wind relatively more cost-effective. In the '10 percent ITC Only' scenario MT wind increases by 570 MW, and in the 'No Tax Credits' scenario MT wind increases by 430 MW. The increases in resource costs did not create a meaningful shift in the relative cost-effectiveness between wind, solar, and storage resources.

Figure 87. Resource additions in 10 percent ITC scenario (MW)

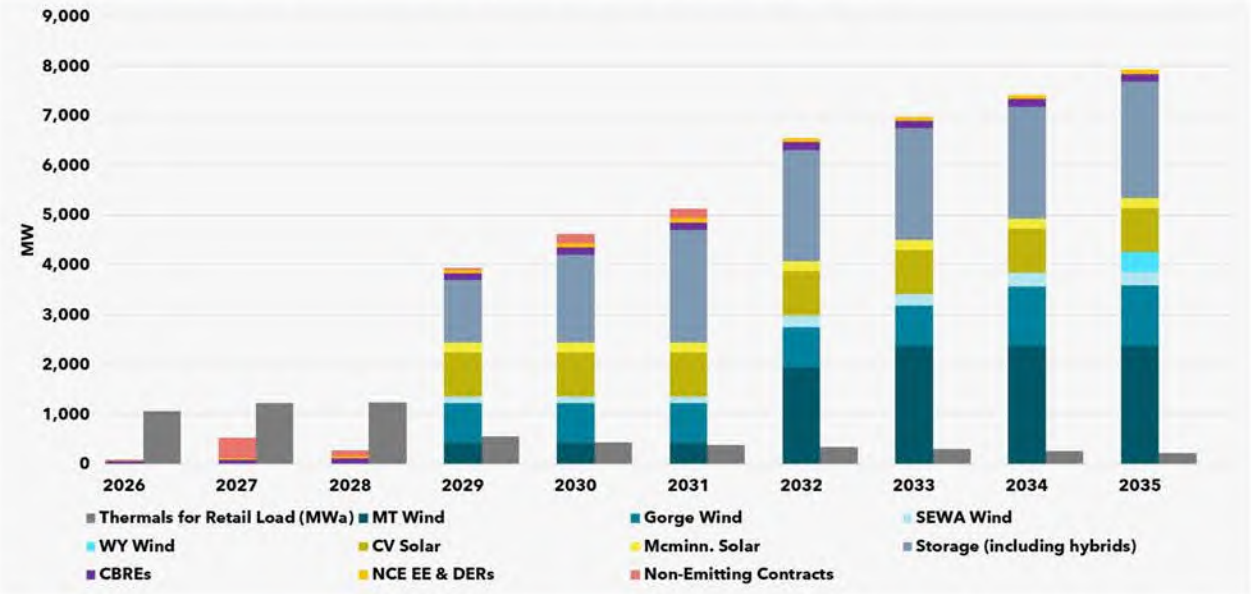


Figure 88. Resource additions in no tax credits scenario (MW)

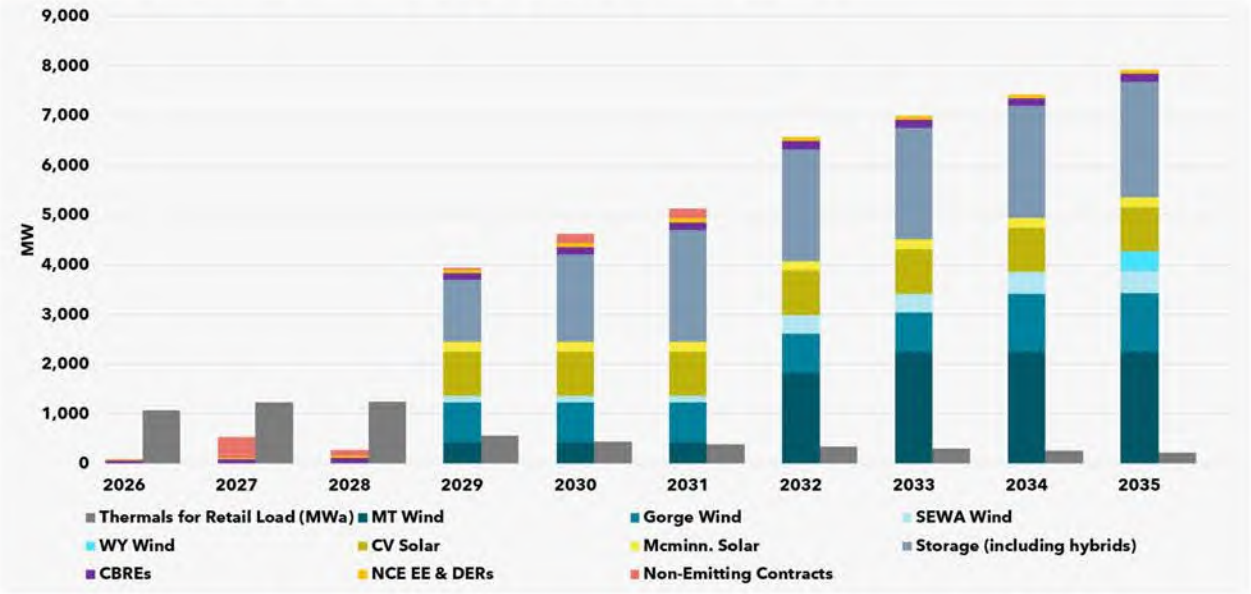


Figure 89 below reflects the annual change in the revenue requirement under all three tax scenarios. This is the incremental cost excluding the baseline existing resource costs. Those costs in addition to the existing portfolio costs results in the portfolio generation cost per MWh shown in **Figure 90**. The most notable changes occur in 2029 and 2040, where the Preferred Portfolio selects a large quantity of resources with large tax credits associated with them. Those cost savings are reduced or removed in the other scenarios.

Figure 89. Annual incremental revenue requirement by tax scenario ($k)

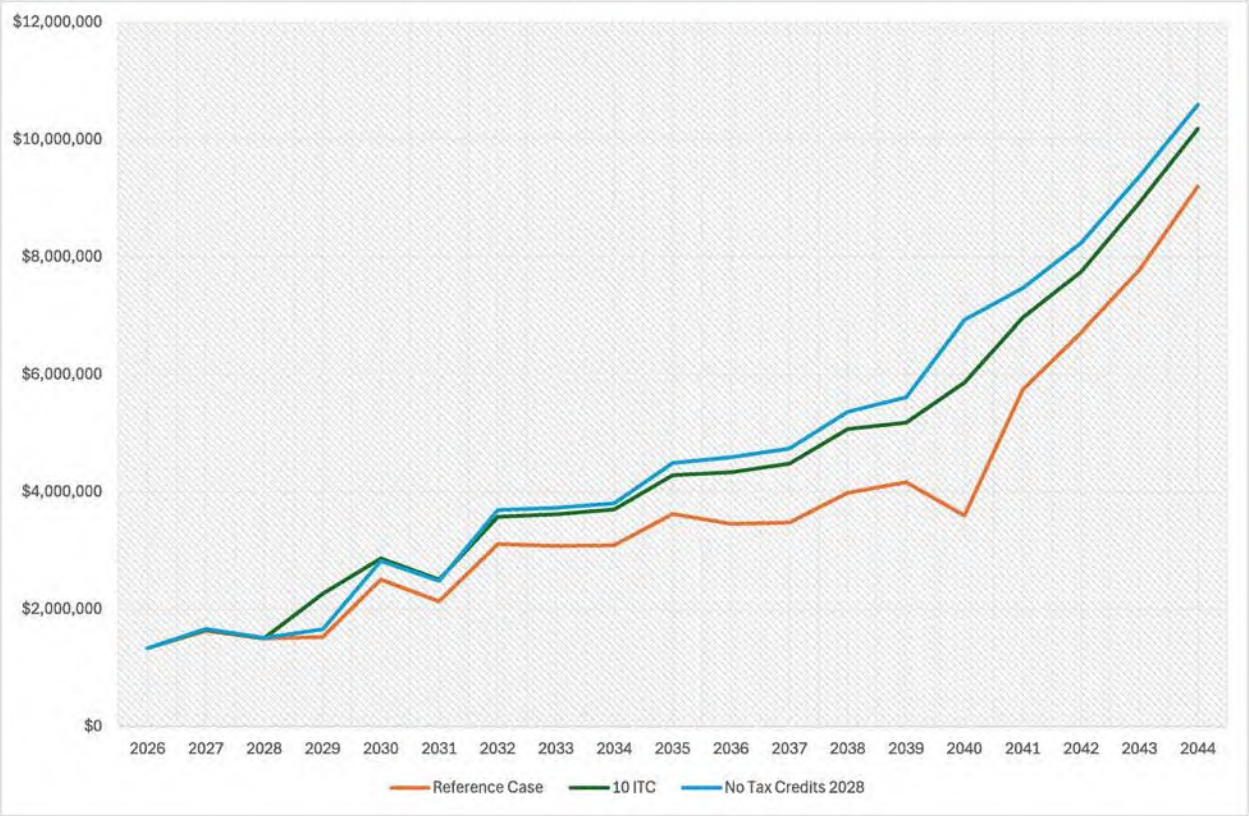
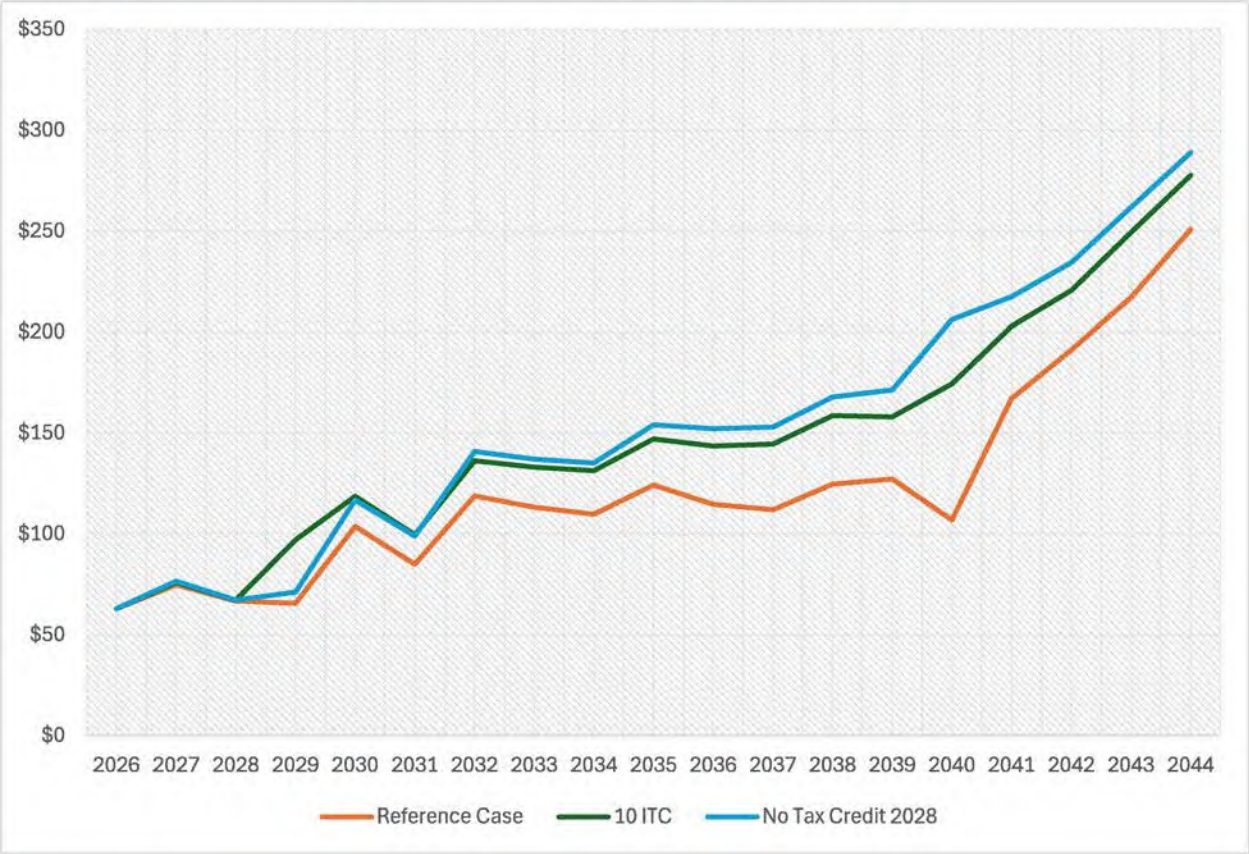


Figure 90. Annual portfolio generation cost by tax scenario ($/MWh)



6.7 Net cost of capacity resources

Candidate resources described in **Section 5.1 Resource economics** flow into the portfolio analysis as well as provide inputs to determine resource capacity values and net costs. Additional specific cost or value assumptions to inform net costs are described below. The resource net costs are not used directly in portfolio analysis, though the resulting capacity value is useful for the purpose of comparing resources or for calculating the administratively determined avoided cost payments for resources procured outside of competitive or negotiated processes. This section provides an overview of updates to Section 10.6 of PGE's 2023 CEP/IRP on the net cost of capacity.

The components previously used to derive the net cost of capacity aligned with a 4-hour battery. However, given PGE's growing capacity needs driven by demand growth, reliability, and decarbonization targets, a battery may not be the most representative new resource due to reliable capacity performance limitations, especially in winter months. PGE continues to investigate alternative resource assumptions to inform net cost results. Presented in **Figure 91** is a bridge approach that looks across costs and benefits for each supply-side resource and weights their contribution to a portfolio-blended value based on each resource's nameplate capacity additions by 2030 in the Preferred Portfolio. Dollar amounts are presented on a levelized basis in 2025 dollars.

- The blended net cost of 1 kW nameplate is $102/kW-yr.
    - This amount is calculated as the sum of all the applicable costs net of any benefits (including tax credits) and represents the cost of capacity to procure 1 kW nameplate of the portfolio-blended proxy resource.
- The blended ELCC of the Preferred Portfolio new resource additions in 2030 is 43 percent.[155]
- The net cost of capacity is calculated by dividing $102/kW-yr by the ELCC of 43 percent, resulting in $237/kW-yr.
    - This represents the Net Cost of Capacity.
- The "ELCC adjusted value" noted in **Figure 91** represents the difference between the net cost of 1 kW nameplate and the net cost of 1 kW of capacity contribution.

Figure 91. Deriving the blended cost of 1 kW of capacity contribution

As discussed in **Section 6.2.3.1 Energy sensitivity adequacy assessment of Preferred Portfolio**, long-duration energy storage appears to possess valuable attributes for meeting PGE's future reliability needs. Preliminary analysis indicates that the net cost of capacity for a 100-hour energy storage resource could fall below the $237/kW-yr threshold detailed above. The assumptions of this initial analysis are summarized in **Table 36**.[156]

[155] This ELCC of each individual resource is based on an average of summer and winter firm capacity additions. The portfolio-blended average ELCC weights each resource's ELCC by its nameplate capacity added in the Preferred Portfolio by 2030.

[156] Cost assumptions from: https://formenergy.com/wp-content/uploads/2025/01/Navigating-the-Pacific-Northwests-Energy-Challenges.pdf

Table 36. Proxy 100-Hour Battery Storage Parameters (2030 COD)

Item	Unit	Amount
All-in Overnight Capital	2025$/kW	2,808
Fixed O&M	2025$/kW	24
Real Levelized Fixed Cost	2025$/kW-yr	218
Round-trip Efficiency	%	35
Useful Life	Years	20

Given the framework and assumptions presented above, the Cost of Capacity for 1 kW nameplate of the Proxy 100-Hour Battery Storage resource is detailed in **Table 37**.

Table 37. Proxy 100-Hour Battery Storage Net Cost of 1 kW Capacity (2030 COD)[157]

Net Cost Component	Unit	Amount
Fixed Costs	2025$/kW-yr	218
Energy Value	2025$/kW-yr	0
Flexibility Value	2025$/kW-yr	0
Cost for 1 kW nameplate	2025$/kW-yr	218
Annual ELCC (100 MW)	%	106
Net Cost of 1 kW Capacity	2025$/kW-yr	206

PGE's preliminary analysis estimates the annual ELCC for the first 100 MW addition of 100-hour energy storage at 106 percent.[158] The resulting Net Cost of Capacity for 1 kW of this resource, given the assumptions, would be $206/kW-yr. As noted above, the net cost of capacity is calculated by dividing the cost for 1 kW nameplate by the ELCC ($218 / 106 percent = $206). The Net Cost of Capacity is less than the $237/kW-yr threshold for ELCC values greater than approximately 92 percent.

[157] Energy and Flexibility values are assumed to be zero for the purposes of this exercise.
[158] Annual ELCC is the average of summer and winter ELCCs as estimated in Sequoia for the 2030 Reference case.

Chapter 7. Action Plan

PGE developed the Action Plan for the 2023 CEP/IRP based on the key findings of the Preferred Portfolio in the 2023 CEP/IRP. Though the Preferred Portfolio has been updated several times since (including this Update), PGE is not making changes to the Action Plan from the 2023 CEP/IRP, as the actions included continue to represent the best combination of cost, risk, community benefit, and emission reductions.

Chapter highlights

- PGE is not requesting Oregon Public Utility Commission acknowledgement of this Update and is therefore maintaining the Action Plan that was acknowledged as part of the 2023 CEP/IRP.
- PGE continues to identify the need for more RFPs to procure additional resources for resource adequacy, reliability, and compliance with HB 2021 GHG emissions targets.
- Updated analysis described in this Update suggests resource need has increased.

7.1 Action Plan

The five actions, as acknowledged by the Oregon Public Utility Commission in the 2023 CEP/IRP, are described in the following sections, as are the potential directional changes suggested by the updated portfolio analysis presented in **Chapter 6 Resource plan**.[159] PGE is not requesting acknowledgement of this Update, and this Action Plan is consistent with that acknowledged as part of the 2023 CEP/IRP.

7.1.1 Customer resource action

- *Action 1A. Acquire all cost-effective EE plus additional quantities identified in the CEP/IRP analysis*

PGE planned to acquire all cost-effective energy efficiency, which was forecast to be a cumulative 182 MWa for 2024 through 2028.

PGE identified 53 MWa of additional EE by 2030 as beneficial for customers over the planning horizon. Within this Action Plan window, by 2028, PGE aims to acquire 32 MWa at lowest cost.

Updated ETO forecasts described in **Section 5.3 Energy efficiency** project cost-effective EE to be 173 MWa for 2025 through 2028. PGE will continue to explore opportunities to deploy

[159] In the Matter of Public Utility Commission of Oregon, PGE 2023 IRP and CEP, Docket No. LC 80, Order No. 24-096 (Apr 18, 2024), Appendix A, p.5, available at https://apps.puc.state.or.us/orders/2024ords/24-096.pdf.

sensible EE measures. PGE will also continue to engage with ETO as guiding principles and potential securitization mechanisms regarding utility rate impacts due to cost-effective EE measures that are developed.

- *Action 1B. Incorporate customer demand response*

  PGE planned to enroll distributed flexibility resources that customers choose to provide. By 2028, this is currently forecast to be a total enrollment of:[160]

  - *211 MW of summer demand response (Low: 173 MW, High: 343 MW)*
  - *158 MW of winter demand response (Low: 127 MW, High: 234 MW)*

Updated forecasts using PGE's AdopDER described in **Section 5.2 Distributed energy resources (DERs)** project increased program participation for a total of 1,269 MW on average from cost-effective DERs in 2030 (a 182 MW net increase from the 2023 CEP/IRP).

7.1.2 CBRE action

- *Action 2: Initiate a CBRE-focused RFP*

  PGE planned to conduct an RFP targeting 66 MW of CBRE resources to come online by 2026.

PGE is conducting a request for offers (RFO) for CBRE resources to support a trajectory towards achieving the target from the 2023 CEP/IRP of 155 MW of CBREs by 2030. PGE's approach to the CBRE RFO has been informed by engagement with and input from community representatives, PGE's CBIAG, potential bidders, and OPUC Staff. Since CBRE is a new type of resource acquisition, PGE has been providing information and exploring appropriate regulatory treatment through regular updates to OPUC Staff. The RFO is open through November 2025, with three rounds of evaluation. PGE anticipates more details and results to be available for the next full CEP/IRP (2026).

7.1.3 Energy action

- *Action 3: Conduct one or more energy RFPs*

  PGE planned to conduct one or more RFPs to add non-emitting resources to support progress toward meeting the 2030 emission targets established in HB 2021. The Reference Case need projected in 2030 was 905 MWa. Through 2028, PGE targeted acquiring 1,254 MWa, or one fifth of that need (251 MWa) per year in the Action Plan (2024-2028).

PGE's baseline portfolio, inclusive of proxy assumptions for procurement from the 2023 RFP, as well as increased EE and DERs, outweigh increased need associated with the new load forecast and other modeling updates. PGE's resulting energy need for 2030 described in **Section 3.3 Energy need** is estimated to be 1204 MWa. This could be thought of as 301 MWa of energy

[160] Demand response values include existing programs.

acquisition necessary in each of the next four calendar years to 2030. At the time of publication of this Update, PGE has two RFPs in progress.

7.1.4 Capacity action

- *Action 4a: Pursue capacity opportunities in the bilateral market*
- *Action 4b: Conduct one or more capacity RFPs*

PGE forecasted significant capacity needs in 2028: 905 MW and 787 MW in the summer and winter, respectively.

Updated analysis described in **Section 3.4 Capacity need** finds PGE's near-term capacity need through 2028 decreased due to supply side additions, namely bilateral contracts, and resource additions modeled as the 2023 RFP Proxy. The updated summer need is estimated at 47 MW in 2026, growing to 485 MW in 2027 with the expiration of hydro contracts with Grant PUD, then drops to 0 MW in 2028 as RFP Proxy Resources enter the modeled supply. In winter, there is 159 MW of need in 2027 that grows through the early years of the analysis period. Actual procurement from the 2023 and 2025 RFPs will seek to fill capacity needs, however, the forecasted near-term need cannot be met by RFP timelines and will therefore need to be addressed by commercial activity in bilateral market purchases.

7.1.5 Transmission expansion action

- *Action 5A: Develop a comprehensive transmission study regarding options to alleviate congestion on the South of Allston (SoA) flowgate*
- *Action 5B: Develop a comprehensive transmission study to explore options to upgrade the Bethel-Round Butte line (from 230 to 500 kV)*

Section 4.6 Transmission options for portfolio analysis describes modeled transmission expansion options through an approach that is consistent with the 2023 CEP/IRP and as informed by new third-party analysis described in **Section 4.5 Third-party assessment of PGE regional transmission options**. Continued study of transmission options will be critical to evaluating access to additional cost-effective clean energy resources ad capacity markets outside of the PNW.

7.2 Conclusion

The 2023 IRP Action Plan, as well as the 2023 and 2025 RFPs are designed to reflect PGE's values and commitment to serving customers with low-cost and clean technologies while mitigating future risks. The Action Plan was developed by estimating system resource needs using forecasts of long-term demand and projections of generation from existing and contracted assets. The difference between that estimated demand and existing supply forms the basis of forecasted system need. To fill that need, all available options and their potential costs and benefits in PGE's system were evaluated. The portfolio analysis was then tailored to answer the most critical questions PGE faces in long-term planning, comparing the relative performance of portfolios

with various combinations of supply-side options. A Preferred Portfolio was created with the best set of incremental resource additions that met system needs while minimizing cost and risk, while maximizing community benefits and considering emissions targets. Finally, an Action Plan was created to act on the key near-term drivers of the Preferred Portfolio. Concurrently with these actions, PGE will continue to work to specify sources of market purchases and accompanying emission rates, utilize funding opportunities to mitigate customer price pressure and implement transmission upgrades within PGE's Balancing Authority and connecting to BPA's system. These actions provide clarity on PGE's priorities and become a tool for future conversation with customers, communities, stakeholders and the OPUC.

Appendices

Appendix A Federal grant funding

The Oregon Public Utility Commission directed PGE to include a report on federal incentive implementation relevant to resource procurement and transmission development.[161] This section outlines the federal grant programs PGE has engaged with, including awarded grants, denied grants, grants still in application phase and instances where PGE withdrew from the application process. As noted in **Section 2.5.2 Grant funding**, changes at the Federal Administration increase uncertainty to the delivery of funding from grants detailed below.

A.1Grants awarded

Grid Services Demonstration Project - USDOE (GID01)

- Project partners: PGE (Lead), Bonneville Power Administration (BPA), Pacific Northwest National Laboratories (PNNL), Portland State University (PSU), University of Texas, Austin (UTA), GE Vernova
- Description: The proposed project will use technologies at the Wheatridge Renewable Energy Facility to create a demonstration concept to show how different types of active and reactive power controls can transform a renewable resource from a simple intermittent energy source to a resource capable of providing a wide range of grid services, such as inertia, voltage and frequency support. Thermal resources currently provide these services and the need to replace such grid stabilizing services will increase with thermal retirement.
- Areas of focus: Grid resiliency, grid modernization
- Project budget: $9-12 million **($4.5 million grant**; $4.5+ million match)
- Grant Phase: Execution

Park and Charge: Leveraging Utility Pole-Mounted Chargers to Increase Access to Overnight EV Charging in Portland, Oregon (GID13)

- Project partners: Portland Bureau of Transportation (PBOT) (Lead), PGE, Pacific Power, Forth, PSU, National Renewable Energy Laboratory (NREL), Columbia-Willamette Clean Cities Coalition
- Description: This project leverages PBOT's jurisdiction over parking policies and permitting of the public right-of-way (ROW) as well as PGE and Pacific Power's existing utility poles to offer an innovative charging solution that is low-cost, scalable, equitable, and accessible. This project will site and deploy 50 Level 2 EV chargers (40 by PGE) on utility-owned poles in the public ROW in existing on-street parking spaces with a focus on underserved communities who lack access to at-home charging.

[161] ORDER NO. 24-096 Staff Recommendation 8 available here: https://apps.puc.state.or.us/orders/2024ords/24-097.pdf

- Areas of focus: EV Adoption
- Project budget (PGE): $**40,000** PGE grant share
- Grant Phase: Execution

Quality Green Jobs Regional Challenge - Jobs for the Future (1st, 2nd , and 3rd phases) (GID14)

- Project partners: Oregon Clean Energy Coalition members (PGE applied on behalf of the Oregon Clean Energy Coalition)
- Description: The Quality Green Jobs Regional Challenge is an initiative that will invest nearly $5 million in communities across the country to develop and implement regional quality green job strategies reaching 25,000 individuals. The OCEWC was one of six regions chosen to participate in all three phases of the challenge. The first phase focused on engagement with key partners including labor, CBOs, employers, governments, and employers. The second phase of the grant focused on building a Quality Green Jobs Agenda included strategies for training and placing Oregonians into jobs within the clean energy sector as well as a statewide market assessment. Phase three will develop and implement an outreach and education model that will work with partners across the state to train and place 5,000 Oregonians in the clean energy sector.
- Areas of focus: Workforce development
- Project budget (PGE): $**10,000 (first phase); $75,000 (second phase); $750,000 (third phase). Pure grant,** no cost share requirement.
- Grant Phase: Execution

Bethel-Round Butte Transmission Line Upgrade (PGE a sub-applicant) - USDOE GRIP (GID05)

- Project partners: Confederated Tribes of the Warm Springs (CTWS) Lead, PGE
- Description: This project, a partnership between the CTWS and PGE, will upgrade the existing 230 kV Bethel-Round Butte Transmission line to 500 kV. The project will accelerate the much-needed development of transmission capacity, enabling new carbon-free generation in Central and Eastern Oregon to reach customer demand loads in Western Oregon, including PGE service territory. Grant funds will directly off-set PGE capital investment costs. The added capacity and associated upgrades will also increase resiliency of the transmission system as well as resiliency of the CTWS Tribal communities by increasing resources available to the Tribes to support adaptation and response strategies. Engineering studies are underway which may impact final project design. Project discussed in **Section 4.6.1 Bethel-Round Butte upgrade**.
- Area of focus: Grid modernization, reliability, decarbonization

- Project budget: ~$860 million ($**250 million grant,** $363 million match over 8 years)
- Grant Phase: Execution

Accelerating and Deploying Grid Edge Computing - US DOE GRIP Grant (GID02): DE-GD0000901

- Project partners: PGE (Lead), Oregon State University, Saturday Academy
- Description: The U.S. DOE selected Portland General Electric (PGE) for a $50 million matching funds grant to deploy Grid Edge Computing (GEC) at approximately 90,000 locations by 2029, across approximately 10 percent of its customer base. GEC is a combination of advanced computing power and software applications deployed on devices at the grid edge, accelerating PGE's grid transformation. The project will use near real-time information from edge computing devices to improve visibility of the electrical system, provide operational insights and improve outage response, and ultimately help to anticipate and mitigate the impacts of extreme weather on grid resiliency. Anticipated benefits include:
    - Local decision-making: Grid adjustments, like demand response, can potentially be made autonomously at the edge
    - Better integration of DERs: Seek to manage and optimize DERs such as EVs and storage at the grid edge
    - Near-Real-time monitoring and control: Detect and respond to grid issues, such as dynamic DER capacity constraints or issues with power quality
    - Improved reliability and resilience: Edge systems ensure critical functions are maintained even during network disruptions or cyberattacks. Customers benefit from fewer outages and more consistent energy delivery.

  Through edge computing and advanced algorithms that collect and analyze grid-edge data, this project will demonstrate how GEC can help accelerate the transformation of PGE's distribution system and help it meet clean energy targets. Advancements from this project that will accelerate grid transformation will be demonstrated through five technical use cases: 1. Real-time grid visibility, 2. Dynamic (near-real-time) DER local capacity insights, 3. DER integration and optimization, 4. Validating DER performance, and 5. Enhanced Grid Resiliency.
- Area of focus: Grid reliability, grid resiliency, grid modernization
- Project budget: Approximately $115 million ($50 million grant; $65 million match)
- Grant Phase: Post award execution

Renewable Hydrogen Production and Generation - USDOE (GID04)

- Note: June 4, 2025, PGE is withdrawing from this grant given the exit of an essential project partner, challenging project economics for utility customers, and potential federal policy changes. PGE does not see a viable path forward for the Boardman Hydrogen Project at a manageable cost.

  Note: PGE is withdrawing from this grant effective June 4th given the exit of an essential project partner, challenging project economics for utility customers, and potential federal policy changes. As a result, PGE does not see a viable path forward for this project at a manageable cost.

- Description: The project will install electrolyzers at PGE's Boardman site in Morrow County to produce hydrogen from renewable electricity, along with on-site storage and hydrogen-only peaker turbines to supply PGE customers with dispatchable non-emitting electricity. The project will also install a pipeline to the Port of Morrow to supply industrial hydrogen uses. Toward the end of the decade the project may add a hydrogen-only pipeline further east to the Port of Umatilla and Pendleton to supply additional uses of clean hydrogen. Project discussed in **Section 5.6.2 Hydrogen and ammonia**.
- Area of focus: Production of hydrogen from renewable electricity; energy storage; use of renewable hydrogen for industrial uses and power generation
- Project budget: $600K Phase 1 to PGE.
- Grant Phase: Execution

Critical Sector Job Quality - USDOL (GID03)

- Project partners: Oregon Clean Energy Workforce Coalition (PGE applied on behalf of the coalition), Clackamas Workforce Partnership, East Cascades Works, Oregon Building Trades and Construction Council, Bricklayers Local 1, Ironworkers Local 29, Cement Masons Local 555, Oregon Department of Corrections, CTWS, Oregon Higher Education Coordinating Commission
- Description: The Coalition's demonstration projects will support building the much-needed clean energy workforce in two distinct areas of the state – Clackamas County and Central Oregon. The first demonstration project will provide a 12-week pre-apprenticeship construction program to adults in custody that are getting ready to transition out of the correctional system. The second demonstration project will provide career learning and career exposure opportunities to opportunity youth (those not connected to work or school).
- Area of focus: Workforce development
- Project budget: Approximately **$3 million** from US Department of Labor; no cost share requirement
- Grant Phase: Execution

Proactive Human-Machine Teaming Enabled Cybersecure Technologies – USDOE Cybersecurity, Energy Security, and Emergency Response (CESER) (GID25)

- Project Partners: Pacific Northwest National Laboratory (PNNL) (Lead), University of Central Florida (UCF), New Jersey Institute of Technology (NJIT), Siemens Technology, PGE, and Florida Power & Light
- Description: The project will develop, validate, and field demonstrate (via red-team testing) human-machine teaming enabled AI/ML tools and algorithms (acronym: 'PROTECT') for operators to perform real-time detection, precise localization, and appropriate mitigation for a wide range of cyber-attacks on DER operations data. The proposed solutions primarily target the cybersecurity enhancement in a DER Operations Center (e.g., DMS/ADMS, DERMS, and DER Aggregators).
- Area of focus: Cyber security
- Project budget: $3.5 million over 3 years; $**200K** PGE no cost share
- Grant Phase: Execution

Forecasting Load and Demand Response during Heat Waves through Large-Scale Sensing and Data Fusion – USDOE (GID35)

- Project Partners: Lawrence Berkeley National Laboratory (LBNL) (Prime), PGE, NREL, AutoGrid
- Description: This project aims at developing novel methods and applications – based on large-scale sensing and data fusion techniques – to estimate the system load during heat waves, provide better forecasts for DR resources, unlock building demand flexibility, and provide information to utilities and ISOs on the process of planning emergency rotating power outages.
- Area of focus: Grid Resilience, Grid Modernization
- Project budget: $1.6 million, PGE In-kind only and no cost share
- Grant Phase: Close Out

Western-based Analysis of Distributed Battery Storage System Emission Benefits and Tradeoffs – USDOE (BENEFIT) (GID34)

- Project Partners: Johns Hopkins University (Prime), PGE, NREL, Columbia University, Arizona Public Service, Rocky Mountain Power, Mandalay Homes, SolarEdge, Sonnen
- Description: This team will evaluate the dispatch and emissions impacts of over 3,000 BESSs associated with residential utility programs in operation across three western-based utilities: APS, RMP, and PGE. The project team will also rely on product manufacturing partners (i.e., Sonnen, Mandalay Homes, and SolarEdge) to gather complementary data on the dispatch,

lifecycle emissions, and related impacts of over 20,000 BESSs nationwide. This information can be used to validate the existing emission benefits/opportunities for BESS, while modeling pathways to co-optimize emission reductions with benefits to the homeowner and utility grids.

- Area of focus: Grid Resilience, Grid Modernization
- Project budget: $1.6 million, PGE In-kind only and no cost share
- Grant Phase: Execution

Sensor Placement, Monitoring, and Data Analytics Platform (Sensor-MAP) - USDOE SETO (GID42)

- Project Partners: NREL (Prime), PGE, Duquesne Light Company (DLC), Open Systems International (OSI), Virginia Tech, Oakridge National Labs (ORNL)
- Description: National Renewable Energy Laboratory (NREL), in collaboration with Portland General Electric (PGE), DLC, OSI, ORNL, and Virginia Tech, proposes to develop and demonstrate Sensor Placement, Monitoring, and Data Analytics Platform (Sensor-MAP), and develop an extensible open-source software suite to perform multistage probabilistic optimal sensor selection and placement that includes observability quantification at both the system and individual state levels; steady-state and dynamic state estimation applications for distribution grids (D-SSSE and D-DSSE) with high levels of distributed energy resources (DERs), including solar photovoltaics (PV); and dashboards for enhancing situational awareness.
- Area of focus: Grid Resilience, Grid Modernization
- Project budget: $3 million, PGE In-kind only and no cost share
- Grant Phase: Negotiation

North Plains Connector - USDOE GRIP (GID20)

- Project Partners: Montana Department of Commerce (Prime), North Plains Connector LLC, Allete Inc, Standing Rock, Northern Cheyenne, Crow Agency, NorthWestern Energy, Basin Electric Power Cooperative, Montana-Dakota Utilities, Minnkota Power Cooperative, PGE, Puget Sound, Avista Utilities, Otter Tail Power Company, Berkshire Hathaway
- Description: NPC is a transformative transmission project that will establish a new 3,000 MW connection between Montana and North Dakota and the eastern and western electrical grids. Project discussed in **Section 4.6.5 North Plains Connector**.
- Area of focus: Grid modernization
- Project budget: Approximately $3.7 billion ($700 million grant (10 percent apportioned for Colstrip Transmission System upgrade); $140 million grant benefit to PGE)

- Grant Phase: Negotiation

Hydropower Incentives - USDOE (GID07, GID37, GID38, GID40)

- Project partners: PGE (Lead), Confederated Tribes of the Warm Springs
- Description: Hydropower facility resiliency, dam safety, and environmental projects at multiple facilities that meet the requirements of the FOA for improvements. Projects proposed at Pelton-Rd Butte, Blue Heron and TG Sullivan plants, and Faraday. Each FERC licensed area is eligible for up to $5 million in grants (70 percent cost share required). Administrative costs incurred by existing PGE staff.
- Area of focus: Hydropower operations
- Project Budget: **$11.3 million** from US Department of Energy for 4 sites
- Project Phase: Negotiation

A.2 Full applications submitted

Oregon Dept of Energy (ODOE) IIJA Resilience Grants - USDOE and ODOE (GID55)

- Project partners: PGE (Lead)
- Description: State formula grants from USDOE to ODOE to enhance electrical grid resiliency and mitigate impacts of wildfires. PGE proposes to expand the microgrid at the Salem Smart Power Center to enhance reliability to several City and State facilities.
- Areas of focus: Grid modernization, Grid resiliency, wildfire mitigation
- Project Budget: Up to $5.54 million ($5.54 million match)

Geothermal with Confederated Tribes of Warm Springs (CTWS) - USDOE (GID63)

- Project Partners: CTWS (Lead), PGE
- Description: Geothermal Resources' Value in Implementing Decarbonization
- Area of focus: Grid Resiliency, Grid Modernization
- Project budget: Grant $1.5M, No cost share requirement

A.3 Application interviews

Distribution System Operator with Virtual Power Plants, Dynamic Operating Envelope, and Competitive Market-Choice (DSO+3) - USDOE STRIVES Topic 1 (GID59)

- Project partners: PNNL (Lead), PGE, Oregon State University (OSU), University of Nevada, Reno (UNR)
- Description: Demonstration of a distribution system operator (DSO) model using (1) virtual power plants (VPP) operating in different modes with different parameters by different entities, (2) a topology- and physics-based dynamic operating envelope (DOE) function managed by the DSO, and (3) competitive market choice (CMC) for consumers through VPP selection and VPP diversity.
- Area of focus: Grid Modernization
- Project Budget: $3 million max grant

A.4 Grants not awarded

Bethel-Round Butte Middle Mile Fiber Project - NTIA (GID33)

- Project partners: PGE (Lead), Peak Internet, Link Oregon
- Description: The project will install a new fiber optic communications cable on the Bethel-Round Butte 230kV transmission path. Peak internet is partnering with PGE to provide broadband services to underserved communities along the transmission path and other partners will benefit from increased communications capabilities for university networks. PGE and BPA will partner to swap fibers for the benefit of both organizations in protecting critical generation and transmission infrastructure.
- Areas of focus: Broadband communications, grid resiliency
- Project budget: $65 million ($30 million grant; $35 million match)

Cybersecurity for Distributed Energy Resources - USDOE (CESER) (GID29)

- Project partners: NREL (Lead), PGE, Iowa State University, Portland State University, OpenEGrid, Avangrid, Xcel Energy
- Description: Develop a cyberattack-resilient DER infrastructure and communications architecture to comprehensively address confidentiality, integrity, and availability requirements in DER communications.
- Area of focus: Grid modernization

Carbon Optimization Framework for Energy Emissions (COFFEE) Grant (Non-IIJA) - USDOE

- Project partners: PGE (Lead), NREL, PSU

- Description: The COFFEE project aims to create a usable and repeatable guide for how to operate and optimize Battery Energy Storage Systems (BESS) and Electric Vehicle (EV) programs for decarbonization.
- Area of focus: Decarbonization
- Project budget: ~$1.5 million ($1.2 million grant, $300,000 match)

Distribution Grid Modernization for Reliability and Wildfire Risk Reduction – USDOE GRIP (GID08)

- Project partners: PGE (Lead), EPRI, PNNL
- Description: The Distribution Grid Modernization project will accelerate the modernization of the distribution grid with the implementation of a variety of technologies like distribution automation and early fault detection along with hardening techniques such as undergrounding of high voltage lines and the installation of covered conductors where appropriate within PGE's High Fire Risk Zones.
- Areas of focus: Wildfire mitigation, grid reliability, grid modernization
- Project budget: Approximately $213 million ($100 million grant; $113 million match)

Enhanced Wildfire Awareness Technologies and Visualization Platforms to Support Public Safety and Community Awareness Initiatives (PGE a sub-applicant) - USDOE GRIP (GID031)

- Project partners: EPRI (Lead), PGE, other confidential partners
- Description: The proposed project will enhance and unify situational awareness capability for wildfire incidents by deploying transformational technology solutions including AI enhanced imaging technologies and multi-purpose micro weather stations that would be integrated into a geospatially referenced data visualization system.
- Area of focus: Wildfire mitigation, grid modernization
- Project budget: Approximately $5 million ($2.5 grant; $2.5 million match)

Operation and Planning Tools for Inverter-Based Resource Management and Availability for Future Power Systems (OPTIMA) – USDOE (GID11)

- Project partners: WSU (Lead), PGE, Utilidata, SW Power Pool, Texas A&M, San Diego State University, Grid Protection Alliance
- Description: In this project, we propose the use of synchronized measurements, both synchrophasors and synchronized point-on-wave measurements, for deriving intelligence on the operational impact of IBRs on power grids.
- Area of focus: Grid modernization, Grid resiliency

Mt. Hood Corridor Resiliency Project (2022-2025) – FEMA (BRIC Grant) (GID16)

- Project partners: Clackamas County (Lead), City of Portland, PGE
- Description: The Mt. Hood Corridor Resiliency Project is a multi-phased critical infrastructure project supporting the resiliency of community lifelines in the northern region of the state. Stage 1 would underground the transmission and distribution lines that power the Bull Run Watershed, which is the primary drinking water supply for nearly one million people in the cities of Gresham, Portland, Fairview, Sandy, and Tualatin. This is the third attempt at this grant.
- Areas of focus: Wildfire mitigation, grid resiliency, grid modernization
- Project budget: Approximately $88 million ($50 million grant; $38 million match)

Undergrounding Powerlines to Reduce Wildfire Risk in National Forests 2024 – IFNF (GID46)

- Project Partners: PGE (Prime), USFS
- Description: Portland General Electric proposes partnering with the U.S. Forest Service to underground powerlines to reduce potential fire starts in a high wildfire risk zone of the Mt. Hood National Forest.
- Area of focus: Wildfire Mitigation
- Project budget: $500,000 (No Match)

Powering Climate and Infrastructure Careers Challenge - Families and Workers Fund – Private (GID28)

- Project Partners: Confederated Tribes of the Warm Springs (lead), PGE, Oregon Clean Energy Workforce Coalition
- Description: The project will support training the workforce needed to enable the state's clean energy transition with a particular focus on providing opportunities for tribal members in pursuit of the tribe's renewable energy development goals on the reservation.
- Area of focus: Workforce development
- Project budget: $1.5 million

Western Bounty Transmission - USDOE GRIP (GID19)

- Project Partners: Nevada Governor's Office of Energy (Prime), ENGIE North America, PGE, Los Angeles Department of Water and Power

- Description: A transformational project that will substantially increase transmission capacity throughout the Western Interconnection on an inter-regional basis while unlocking and enabling between 15-29GW (or more) of otherwise inaccessible high-quality remote renewable resources. Western Bounty is a multi-terminal and bi-directional voltage source converter (VSC) high voltage direct current (HVDC) system in a "hub and spoke" arrangement.
- Area of focus: Grid modernization
- Project budget: Approximately $12 billion ($1 billion grant, $11 billion match) PGE support only, no matching funds

Scale Smart Managed Charging and Enhance Grid Resilience through Enriched Grid Edge DERMS (DSO+3) - USDOE Connected Communities Topic 1A

- Project partners: PGE (Lead), OSU
- Description: Enrich PGE's Grid Edge Distributed Energy Resource Management System (DERMS) integrations to scale Smart Charge Management to more EVs in PGE's territory and to inform investigation of scalable, utility-side load optimization strategies and grid resiliency support.
- Area of focus: Grid Modernization
- Project Budget: ~$3 million

An Energy Resilience Planning Tool for PGE - USDOE CESER

- Project Partners: PGE (Prime), PNNL
- Description: PGE and PNNL have assembled an integrated team driven by common goals, led by experts in the key research areas, and supported by PNNL's institutional capabilities related to data hosting, live data feeds, high-performance computing, cybersecurity, all aspects of grid operations, T&D modeling, and energy assurance planning. PGE's EGRASS platform will leapfrog current solutions by integrating varied multi-hazard impacts into a high-resolution T&D system. The statistical analyses and microclimate forecasts will lead to more accurate outage forecast in advance of actual outages, minimizing customer impacts.
- Area of focus: Grid Resilience
- Project budget: Approximately $3.5 million ($1.2 million grant, $1.3 million match)

Wildfire and All Hazards Modeling and Mitigation Consortium - USDOE GRIP (GID09)

- Project partners: Avista Utilities (Prime), PGE, Chelan County Public Utility District, City of Drain, City of Monmouth, Consumers Power, Forest Grove Light & Power, Blachly-Lane Electric Cooperative, Clark Public Utilities, Northern Lights, Inc., Douglas Electric

Cooperative, Puget Sound Energy, Inland Power & Light Company, Kootenai Electric Cooperative, Northwestern Energy, Lawrence Berkeley National Lab, Pacific Northwest National Lab

- Description: Avista Utilities is partnering with utility experts from across the Pacific Northwest, National Laboratories, universities, and private innovators to combat increased wildfire and all hazard threats to the electrical distribution system. The consortium will develop a granular wildfire risk model and methodology, and high-definition weather model, enhancing all consortium members' ability to assess wildfire risk and inform all hazards mitigation decisions. The weather model will enable consortium utilities to better assess impacts and minimize operating risks to the electrical system from extreme weather events, including fire weather, in both real-time and for the planning horizon.
- Areas of focus: Wildfire mitigation, grid resiliency, grid modernization
- Project budget: Approximately $507 million ($250 million grant; $257 million match)

Mobile Batteries for Adaptive Resilience - USDOE GRIP (GID17)

- Project Partners: Avista Utilities (Prime), PGE
- Description: DOE funding would allow the project partners to develop and deploy an innovative battery solution to provide a more adaptive and resilient grid. Each microgrid will include one or more interfaces for fast connection of mobile energy storage systems, plus allow for expansion to include solar, EV charging, and additional storage.
- Area of focus: Grid resilience
- Project budget: Approximately $40 million ($20 million grant; $20 million match)

West Coast Real-Time Inertia Measurement Project - USDOE GRIP (GID21)

- Project Partners: RT Technologies USA INC. (Prime), CAISO/RC West, Southern California Edison, PacifiCorp, PGE, and EPRI
- Description: RT has developed an innovative, first of a kind technology which provides operators with access to unique highly accurate, continuous and direct, real-time inertia measurement and analytics data for the grid. GridMetrix® uses this patented, world-first, breakthrough method to maximize the safe and reliable integration of renewable energy. Grid operators can now make informed decisions about inertia level and renewable grid frequency stability. With a stable grid and rapidly scaling up renewables and scaling down fossil fuels, a net zero carbon grid can be achieved safely, reliably, and faster.
- Area of focus: Grid modernization
- Project budget: Approximately $30 million ($15 million grant, $15 million match)

Grid Copilot for an Electrified, Decarbonized & Empowering Grid - USDOE (GID61)

- Project Partners: GE Vernova (Prime), Florida Power & Light, Duke Energy, Commonwealth Edison, Portland General Electric, Avista Utilities, Alfred University, University of Central Florida, University of California Riverside, Amazon Web Services
- Description: Grid Copilot is powered by a physics-informed artificial intelligence (AI)-based digital twin of the grid, overcoming limitations with traditional engineering techniques, in providing real-time and predictive monitoring and situational awareness analytics, robust recommendations and automated solutions for digital grid control, big data validation and cleaning, online simulation coach to train utility workforce, and an agent to engage developers and communities suggesting a diverse mix of energy resources for accelerated interconnection.
- Area of focus: Grid Resilience/Modernization
- Project budget: Approximately $200 million ($100 million grant, $100 million match)

Weavegrid - USDOE GRIP (GID62)

- Project Partners: Weavegrid (Prime), PGE, Avista, PSE, PG&E, SCE, BGE, Xcel, Alabama Pwr, Georgia Pwr, TEP, PEPCO, Orange & Rockland, Eversource, Luma
- Description: Managed EV charging to enhance grid resilience.
- Area of focus: Grid Resiliency, Grid Modernization

Vegetation-based ignition risk characterization and comprehensive near-term wildfire risk mitigation - USDOE CESER

- Project Partners: GE Vernova (Prime), WSU, PGE
- Description: GEVAR team is proposing to create a comprehensive framework and tools to mitigate wildfire risk with optimized vegetation management and Public Safety Power Shutdown (PSPS) events as well as minimize the impact of PSPS on the communities.
- Area of focus: Grid Resilience
- Project budget: Advisory Committee Only

Hydropower Incentives - USDOE (GID39, GID41)

- Project partners: PGE (Lead), Confederated Tribes of the Warm Springs
- Description: Hydropower facility resiliency, dam safety, and environmental projects at multiple facilities that meet the requirements of the FOA for improvements. Projects proposed at Pelton-Rd Butte, Blue Heron and TG Sullivan plants, and Faraday. Each FERC licensed area is eligible for up to $5 million in grants (70 percent cost share required).

- Area of focus: Hydropower operations
- Project Budget: $11.3 million across multiple sites

A.5 Pending grant opportunities awaiting federal guidance

Distribution Grid Technology and Modernization Partnership - USDOE GRIP (GID06)

- Project partners: PGE (Prime), Umatilla Electric Coop, Eugene Water & Electric Board, Clark Public Utilities, Pacific Northwest National Labs
- Description: This project concept aims to remove barriers to participation by leveraging the ADMS and DERMS system already in service at PGE's state of the art Integrated Operations Center (IOC). A new, replicated system will be stood up for consortium utilities to manage and operate their distribution networks, in a secure geofenced segment of the system.
- Areas of focus: Grid modernization, DER integration
- Project budget: Approximately $100 million ($50 million grant; $50 million match)

Data Center Flexibility as a Grid Enhancing Technology - USDOE GRIP (GID18)

- Project Partners: Virginia Department of Energy (Prime), Maryland Clean Energy Center, Oregon Department of Energy, North Carolina Department of Environmental Quality, Amazon, Rappahannock Electric Cooperative, PGE, Georgia Power, PacifiCorp, North Carolina Electric Cooperatives, (Exelon), Intel, LevelTen Energy, Grid Forward
- Description: Utilities will invest in a range of grid-enhancing technologies to expand transmission capacity and support the more flexible interconnection of large data center loads. DC operators will leverage on-site generation, storage and load control capabilities to support regional grid operations. The utilities, operators and state energy officials will collaborate on potential new tariff designs, utility programs and cost-benefit assessments to replicate the concepts and capabilities demonstrated.
- Area of focus: Grid modernization
- Project budget: Approximately $700,000,000 ($250 million grant; $450 million match)

Agentic AI for Automated Interconnections - ConnectWerx, USDOE (GID67)

- Project Partners: ThinkLabs AI (Lead), PGE, ISO New England, NYISO, National Grid, TVA, UC Riverside
- Description: This project is expected to provide guidance on existing interconnection process and bottlenecks, data needed for building the AI models, evaluate results of AI-assisted analysis and compare against existing approach, and potential deployment in appropriate Cloud environment for end-to-end testing.

- Area of focus: Grid Modernization
- Project budget: Grant $12M+, No cost share requirement

Connected Communities - TechWerx (USDOE) (GID68)

- Project Partners: Resource Innovations (Lead), PGE
- Description: Resource Innovations will develop a platform to take in AMI and program participation data and produce per-participant, hourly grid impacts for demand response and flexible load measures that account for load diversity.
- solutions to support decarbonization and grid modernization efforts.
- Area of focus: Grid Modernization
- Project budget: Grant $1M, No cost share requirement

Appendix B Sequoia methodological update

PGE made one methodological update in Sequoia as part of the 2023 CEP/IRP Update. The result of this methodological change allows Sequoia to model the most recent 30 years of historical load and generation data, shifting the analysis period from 1992-2021 to 1994-2023. This shift in analysis period allows Sequoia to model more recent weather effects on load and variable energy resources.

Updating the analysis period in Sequoia required redefining the day-type characterization, or load bins, of historical days.[162] Consistent with past versions of Sequoia, load-bins are five equally sized percentile ranges (i.e. 0^{th}-20^{th}, …, 80^{th}-100^{th}) of weather-dependent load used to match demand with variable energy resources (VERs). Load-bins allow Sequoia to simulate various plausible load and VER generation scenarios under the assumption that temperature, load and generation from VERs are correlated. The effects from the updated analysis period are reported in two steps: 1) changes to the method used to estimate the 1992-2021 weather-dependent load from which load-bins are calculated; and 2) redefinition of load-bins using 1994-2023 weather-dependent load as estimated from the updated methodology.

For PGE's resource adequacy modeling purposes, weather-dependent load for years 1980-2019 was estimated at hourly intervals one time using a neural network model produced by external consultant, E3. IRP analysts incrementally added hourly load shapes for years beyond 2019, backward adjusting the incremental load to remove the influence of population growth, economic changes, and other influences on load that are not weather-dependent. The manual approach used to detrend load motivated the development of a more rigorous and reproducible methodology.

For the Update PGE developed a regression model to estimate weather-dependent load using fixed effects and daily weather measurements as specified in **Equation 1**.[163] Where $\widehat{MW_t}$ is the estimated load in MW for hour t, given the daily temperature in degrees Celsius for midpoint, heating degrees, cooling degrees, maximum and minimum. X_{it} represents various fixed effects as indicator variables for: year, month, hour, day of week, holiday, and weekend.

Equation 1. Weather-dependent load using fixed effects and daily weather measurements

$$\widehat{MW_t} = \beta_0 + \beta_1 MidpointTemp_d + \beta_2 HeatingDegrees_d + \beta_3 CoolingDegrees_d + \beta_4 MaxTemp_d + \beta_5 MinTemp_d + \beta_i X_{it}$$

[162] For more information on day-type characterization see 2019 IRP Appendix K.1.1.

[163] The IRP elected to use a random-forest algorithm due to improved out-of-sample accuracy compared to ordinary least-squares (OLS) regression. Random-forest estimation explained 98 percent of load variability with a mean absolute error (MAE) of 57 MW, while OLS estimation explained 93 percent of variability with MAE of 124 MW. **Equation 1** is specified as an OLS regression for interpretation purposes only, covariate weights for random-forest algorithms are not calculated as coefficients as in ordinary least squares.

The model was trained on a sample of 361,849 observations and tested on an out-of-sample set of 178,225 observations. Accuracy metrics on the out-of-sample set showed 98 percent of the variability in load was captured, with an average absolute error of 57 MW. After training the model, weather-dependent load was estimated by simulating historical hourly demand from 1960-2023 in MW from year 2023. Estimated capacity need for the 2028 reference case using the updated weather-dependent load profile is 11 MW and 13 MW greater for winter and summer, respectively. Finally, shifting the analysis period forward 2 years (1994-2023) and re-calculating load-bins using the updated weather-dependent load shape results in an additional 3 MW of winter and 33 MW of summer capacity need for the 2028 reference case.

Appendix C QF capacity update

As part of this Update, Qualified Facility (QF) capacity estimates were updated in Sequoia to align with contracted and online resources. Sequoia uses monthly estimates of QF MW capacity as proxied by six distinct resources: Biogas, Geothermal, Hydro, PV East, PV West, and Wind. Individual QF resources are grouped into the above categories to simplify modeling assumptions. Two assumptions are included in the estimation of QF capacity based on Order 24-96. The first is that for those QF projects that are contracted but not yet operating, it is assumed that 75 percent of the MW will reach operation. Second, a 75 percent renewal rate of QF capacity is assumed after contract termination. Estimated MW for the 2028 Reference Case are listed in **Table 38**, in addition to a comparison to pre-update modeling assumptions.

Table 38. Modeled QF Resources

Modeled QF Resource	2023 IRP (MW)	2023 IRP Update (MW)	Change (MW)
PV West	139.65	134.66	-4.99
PV East	263.25	234.25	-29
Biogas	5.2	8.92	3.72
Geothermal	0	0	0
Hydro	4.04	7.19	3.15
Wind	29.15	29.15	0

There is a net 27.12 MW reduction in QF capacity for the 2028 Reference Case. The 35 MW decrease in modeled resources is due to a 29 MW and 4.99 MW reduction in capacity for PV East and PV West, respectively. An increase of 3.72 MW and 3.15 MW of Hydro and Biogas resources, respectively, account for the remaining differences in estimated QF capacity.

Appendix D Hourly emissions methodology

This section outlines the steps that PGE has taken to update its GHG emissions forecasting to incorporate hourly analysis of its energy and emissions accounting.

These steps make assumptions about thermal generation and market purchases specified in the IGHG model to produce an hourly system position and resulting emissions impacts using the following:

- An alternative approach to production cost modeling that balances the hourly system position in Aurora to produce an hourly allocation of IGHG-constrained thermal generation, hydro and storage dispatch optimized around serving PGE retail load and provide the final validation of the Preferred Portfolio by generating a resource dispatch output that results in a system position consistent with HB 2021 compliance.
- An allocation of IGHG-allocated market purchases across hours of remaining need.
- An hourly accounting of the availability and price premium associated with a WECC-wide clean energy surplus estimate. These estimates were estimated by The Brattle Group and are used to reflect the contribution that the non-emitting market can provide in supporting PGE's hourly energy position.

D.1Challenges with existing IRP emissions reporting

In the 2023 CEP/IRP, the PZM was used to simulate PGE existing dispatchable generation resources, contracts and new resources using economic dispatch based upon electricity prices[164]. The electricity prices contained risk variable inputs that vary across each of the 39 forecasts of electricity prices. When a resource is economically dispatched, market price exceeds the variable cost of operation.

The PZM simulation forecasts total resources generation but does not distinguish between generation associated with retail load and wholesale sales. This gap was addressed using the IGHG model. This step used the GHG emissions reduction glidepath and historical estimates of wholesale market transactions to estimate the amount of energy dedicated to wholesale sales and the amount of energy dedicated to PGE retail load service for each GHG-emitting source. The estimated amount of emitting energy used for PGE retail load service is incorporated into the capacity expansion model (ROSE-E).

By economically dispatching PGE resources to the price forecasts simulated by the WECC model, PGE is assuming the presence of a regional market in which PGE is a pure price taker. Relative to the size of the entire Western Interconnect, PGE comprises less than 3 percent of the total load as measured by peak loads. No quantity of PGE market purchases or market sales will change the WECC price forecasts. Adapting this methodology to demonstrate that PGE is compliant with HB 2021 emissions requirements is difficult given that partitioning emitting

[164] Outlined in Appendix H.1.2 of PGE's 2023 CEP/IRP.

energy to wholesale sales from retail load service is a complex modeling challenge. This is the original reason for using the intermediate IGHG Model as a bridge between production cost and capacity expansion models.

PGE can allocate thermal generation to serve retail load (up to the emissions target for HB2021 compliance) or sell it to the wholesale market. In prior analysis, PGE experimented with post-model adjustments to thermal dispatch that removed thermal dispatch directed to serve wholesale sales by prioritizing thermal generation for when retail load hours are shortest (deficit-sorting) and during hours when prices are highest (price-sorting).[165] Neither method allowed the model to co-optimize thermal generation with other dispatchable resources such as storage or hydro. The result presented an improvement in the hourly representation of PGE system, but the methodology leaned on out-of-model adjustments.

At this point there is no simple way to develop market logic in Aurora that would allow thermal units to choose between unconstrained wholesale sales and constrained retail load service within the PZM in time for the 2023 CEP-IRP update. The current methodology in the PZM uses WECC input price forecasts to dispatch resources. The methodology in which resources are dispatched to forecasted market prices is limited in its ability to represent the disaggregation of thermal generation into an unconstrained wholesale market and retail load service with an annual emissions cap.

The remainder of this appendix shows the methodology used to adapt PGE's production cost model to better represent PGE's hourly energy and emissions position in 2030. Section D.2 provides the change in model dispatch logic that addresses the challenges described in the previous section while discussing how thermal generation is allocated to retail load subject to the HB 2021 emissions constraint. Section D.3 discusses modifications to the dispatch of storage generation that result from the change in modeling logic. Section D.4 shows how non-emitting market availability is incorporated in the new hourly energy and emissions modeling.

D.2 Modifications to model dispatch logic and thermal dispatch

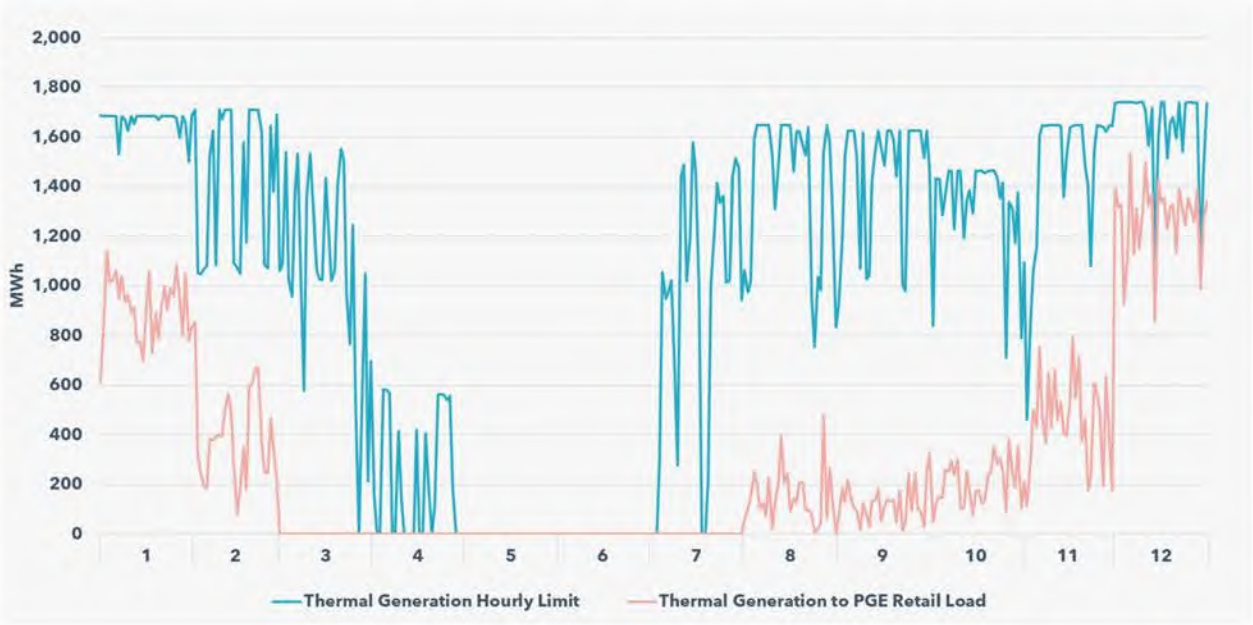
To solve the problem identified in **Section D.1**, PGE has modified the PZM to dispatch PGE resources at minimum cost subject to the constraint that retail load obligations are met with the HB 2021 annual emissions cap in place. This model is called the Modified PZM. The effect of changing the dispatch logic from dispatching resources to price to dispatching resources to meet retail load allows PGE to model how PGE's Preferred Portfolio can meet its hourly retail load requirements and comply with the annual GHG emissions limit. The model can choose the timing of the thermal dispatch from the total economic dispatch (both retail load service and wholesale sales) that is previously determined in the PZM. The Modified PZM will dispatch the portion of that thermal generation allocated to serve retail load service from the IGHG model. This is represented in the Modified PZM by an hourly cap on emissions (by thermal resource) determined by the total economic dispatch level set by the PZM. This allows the Aurora

[165] Portland General Electric Company. (2023, November 21). LC 80 – Portland General Electric Company's 2023 Clean Energy Plan and Integrated Resource Plan: Reply to Staff Round 2 Comments and Recommendations.

optimization to select the hourly profile of the total annual thermal energy dedicated to serve retail load as calculated in the IGHG Model.

Hourly thermal limits are also placed on thermal generation to prevent using thermals during hours deemed uneconomic in the PZM (where resources are dispatched against WECC-wide market prices). This is depicted as the blue line in **Figure 92**. The red line provides the timing of thermal output used to serve PGE retail load in the mPZM.

Figure 92. Thermal Generation Hourly Limits & Thermal Generation to PGE Retail Load by Month

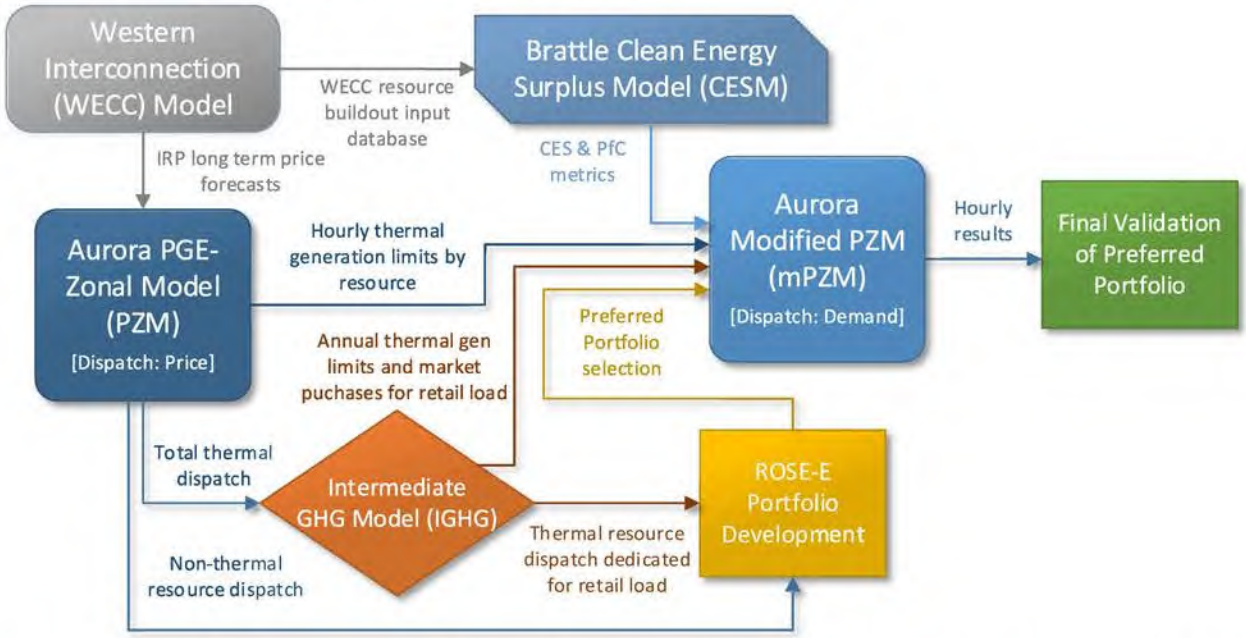


The results of the Modified PZM system dispatch are sent to the excel-based Hourly Energy and Emissions Accounting Workbook (Hourly Workbook). The Hourly Workbook is designed to apply the IGHG-allocated unspecified market purchases using the price-sorting methodology. Any remaining short energy position is applied the unspecified emission rate of 0.428 mmtCO2e in accordance with the Oregon DEQ reporting methodology in OAR Chapter 340, Division 215. From this, the emissions impact is calculated and the determination of compliance with HB 2021 is made based upon the modeled selected portfolio.

In addition, the Modified PZM incorporates hourly information about the availability of clean energy from the market and the corresponding price premium attached to this clean energy. **Section D.4 Incorporating non-emitting market generation** discusses how the market for non-emitting energy is incorporated into the Modified PZM.

Figure 93 below outlines the flow of data and connectivity between the models as it pertains to hourly energy accounting.

Figure 93. IRP modeling diagram Hourly Energy Accounting



The purpose of the Modified PZM Aurora model and hourly workbook is to (1) provide ROSE-E with information on the remaining short positions after applying the IGHG-allocated thermal generation and market purchases such that ROSE-E can weight its portfolio selection as outlined in Portfolio Analysis and (2) determine whether the portfolio of resources selected by ROSE-E provides sufficient resources to meet hourly retail load requirements and GHG-compliance needs. The Modified PZM model is focused on calculating the 2030 energy position to meet hourly retail load obligation and emissions compliance constraints and does not calculate energy values for purposes of minimizing net cost in portfolio optimization. That function remains the purpose of the PZM.

D.3 Change in storage dispatch logic

In the PZM, storage dispatch only considers the value of price arbitrage, or the ability to reshape energy across the day by charging when prices are low and discharging when prices are high. If the dispatch of thermal resources is not constrained by emissions, then this dispatch outcome is the lowest cost solution subject to the parameters chosen.

However, given the constraints imposed by HB 2021, the dispatch of storage resources should include the opportunity cost of emissions. Within any given emissions budget, an additional ton emitted from one generation resource requires a reduction of one ton from somewhere else. The opportunity cost of an additional emission is the cost of this offsetting reduction in generation. Since the cost of the offsetting reduction in generation is not included in the storage dispatch logic, the PZM results will be sub-optimal under the following outcomes:

- Storage discharged to provide energy in excess of retail load due to high prices. This energy could have been saved for another hour in which PGE is short and the market price is lower (displacing emitting resources or market purchases in future hours). The

price difference between the high-priced hour and the low-priced hour must be less than the opportunity cost of emissions.

- Storage is charged to consume energy in deficit of retail load due to low prices. This energy could have been consumed during another hour in which PGE is long and market price is higher (displacing emitting resources or market purchases in current hour). The price difference between the high-priced hour and the low-priced hour must be less than the opportunity cost of emissions.

This problem is solved by changing the model dispatch logic such that storage resources are dispatched economically to internally generated hourly prices that are solved by using model supply and demand conditions instead of by using externally-provided forecasted input prices as is used in the PZM. This change in logic prioritizes storage dispatch to move energy across the day from hours in which PGE has excess energy to hours in which PGE has excess demand instead of prioritizing storage dispatch logic to arbitrage market prices. This is useful in maximizing the displacement of emitting thermal generation using storage to meet system needs and provides a better representation at how well the Preferred Portfolio can meet PGE system needs when PGE's system is emissions constrained.

D.4 Incorporating non-emitting market generation

The yearly IGHG model in the 2023 PFC/IRP utilized an assumption that PGE was able to rely upon market purchases above the allocated market purchases in the IGHG model at times in which it was short. With this assumption, the average hourly position was 9 MWa long in 2030.[166] This conclusion relied on the assumption that PGE will be able to sell emitting generation at no price discount for market sales above those allocated by the IGHG model. Inversely, this conclusion also relied on the assumption that PGE will be able to access non-emitting generation at no price premium for market purchases above those allocated by the IGHG model.

- If this assumption was true, then this analysis indicated that meeting emissions targets with the Preferred Portfolio's set of incremental resource additions is possible under expected conditions.
- If this assumption was false, then both PGE and Staff's draft analyses were in alignment. Both pointed to a need for an increased quantity of non-emitting generation to be acquired between now and 2030 to ensure compliance with HB 2021 under expected average conditions.

PGE recognized that if there is no market to buy non-emitting energy in the hours that PGE is short, forecasted need required allocating additional emissions to those market purchases to balance. In the analysis provided in LC 80: PGE's Reply to Round 2 Comments, PGE

[166] Portland General Electric Company. (2023, September 6). *LC 80 - 2023 Clean Energy Plan and Integrated Resource Plan: Reply to Round 1 comments* (p. 53). Oregon Public Utility Commission. [https://edocs.puc.state.or.us/efdocs/HAC/lc80hac131341.pdf]

demonstrated that under the condition of no market for non-emitting generation, additional resource procurement would be needed to comply with annual cap on GHG emissions.

In response to these concerns, PGE contracted The Brattle Group to develop a high-level framework for estimating WECC-wide and regional analysis of the market for non-emitting energy to serve as an input into the hourly energy and emissions accounting modeling. The Brattle Group performed an analysis of the regional WECC market and provided PGE with forecasts of the availability and price premium of non-emitting or clean energy available to PGE in 2030. The Clean Energy Surplus (CES) is the clean energy available beyond that which is needed to meet annual state-level clean energy targets and the Premium for Clean (PFC) is the additional cost beyond the energy price associated with the purchase of surplus clean energy.

Brattle used PGE's IRP Aurora results from the Regional WECC model that is used to generate PGE's IRP Price Forecasts and other input parameters capturing regional data on state clean energy requirements to calculate the CES. After allocating the annual CES across hours of the year, Brattle applied deliverability constraints to determine how much CES is available to PGE in Oregon West for each hour of 2030. In addition, Brattle used the CES to calculate the PFC by hour in the analysis. For a detailed description of the Brattle Analysis, read **Appendix F Market for non-emitting energy**.

The Modified PZM incorporates the CES and PFC by including the CES as a market resource available up to the hourly deliverable energy to Oregon West Zone. This market energy is priced at the sum of the forecasted Oregon West hourly price plus the hourly PFC. The Modified PZM optimizes dispatchable generation and available non-emitting market purchases to leverage PGE's generation, contracts, and the regional diversity in clean energy to meet its HB 2021 compliance goals.

When the results of the Modified PZM analysis contains a summation of short hours less than the quantity of unspecified market purchases, the hourly workbook reallocates non-emitting market purchases to replace non-emitting market purchases to that extent that the full IGHG allocation is exhausted. This is accomplished by replacing the hours with the largest Premium for Clean first as ranked from highest to lowest. Given a budget of unspecified market purchases, total cost will be minimized by purchasing unspecified energy instead of clean energy from the market when the Premium for Clean is highest. This method is also indicative of the likelihood of finding energy in the clean energy market–it will be more difficult to procure clean energy when the Premium for Clean is non-zero.

Appendix E Energy Trust of Oregon (ETO)

Energy Trust of Oregon

PGE Energy Efficiency

2025 Resource Assessment Model

Energy Trust of Oregon Background

Energy Trust of Oregon, Inc. (Energy Trust) is an independent nonprofit organization dedicated to helping utility customers in Oregon and Southwest Washington benefit from energy efficiency and renewable power. Energy Trust operates under a grant agreement with the Oregon Public Utility Commission (OPUC).

As a result of state legislation, tariffs and other requirements, Energy Trust is funded by customers of Portland General Electric, Pacific Power, NW Natural, Cascade Natural Gas and Avista. Energy Trust's model of delivering energy efficiency programs unilaterally across the service territories of the five gas and electric utilities they serve has experienced a great deal of success. Since the inception of the organization in 2002, Energy Trust has achieved total annual savings of 1,025 aMW of electricity. Additionally, Energy Trust has saved 103 million therms since gas efficiency programs began in 2003. Combined, this equates to more than 40 million metric tons of CO2 emissions avoided, and Energy Trust has played a significant factor with relatively flat energy loads observed by both gas and electric utilities from 2014 to 2023, as shown in OPUC utility statistic books.[1]

Energy Trust, with support from PGE, serves residential, commercial and industrial customers in Oregon. In 2024, Energy Trust's service to PGE customers through energy efficiency programs achieved 37.8 aMW of electric savings achieving 132% of goal. Energy Trust achieved electric savings at a utility levelized cost of 0.035$/kWh, meeting OPUC performance measures to achieve electric savings at a levelized cost below 0.046 $/kWh.

PGE actively promotes Energy Trust offerings to its customers and supports their participation in Energy Trust efficiency programs. Also, when shared technologies and programs are mutually beneficial, PGE coordinates its demand response program activities with Energy Trust's energy efficiency programs. For example, smart thermostats are used by PGE for demand response, but also provide energy efficiency savings, which the Energy Trust counts towards its energy saving goals.

In addition to administering energy efficiency programs with support from PGE, Energy Trust also provides a 20-year demand-side management (DSM) resource forecast to identify cost-effective energy efficiency savings potential. This forecast examines how much of that potential is estimated to be achieved by Energy Trust over the 20-year period. The results are used by PGE and other utilities in Integrated Resource Plans (IRP) to inform the energy efficiency resource potential Energy Trust expects to acquire in their territory, helping to offset the need for new generating resources to meet projected load growth.

Energy Trust Forecast Overview and High-Level Results

Energy Trust developed a 20-year DSM energy efficiency resource forecast for PGE using Energy Trust's resource assessment modeling tool (hereinafter 'RA Model') to identify the total 20-year cost effective modeled energy efficiency savings potential. Energy Trust then deploys this cost-effective potential exogenously to the RA model into an annual energy efficiency savings projection based on past program

[1] OPUC 2023 Stat book – 10 Year Summary Tables: https://www.oregon.gov/puc/forms/Forms%20and%20Reports/2023-Oregon-Utility-Statistics-Book.pdf

experience, knowledge of current and developing markets, and future codes and standards. This final 20-year savings projection is provided to PGE for inclusion in their Integrate Resource Planning (IRP) forecasts. The 2025 IRP results show that PGE can save 171.7 average megawatts[2] (aMW) in the next five years from 2025 to 2029 and over 675 by 2043.[3] These results represent an 11% and 22% increase respectively in deployed cost-effective DSM potential over the prior IRP in 2023. The main drivers of this increased potential are:

1. Growth in the PGE load forecast, most notably in the commercial sector.
2. Growth in avoided costs.
3. Updated measure assumptions, new measures and updated market characterizations.
4. Lighting market transformation and HB 2531. While Energy Trust will not claim the bulk of these savings, they are still expected to come off PGE's system and thus savings are included in this forecast.
5. Residential electrification.

Figure 1 depicts the full suite of savings potential identified in the model by potential type (Technical, Achievable, Cost-effective achievable).

Figure 1 – 20-year Savings Potential by Sector and Potential Type

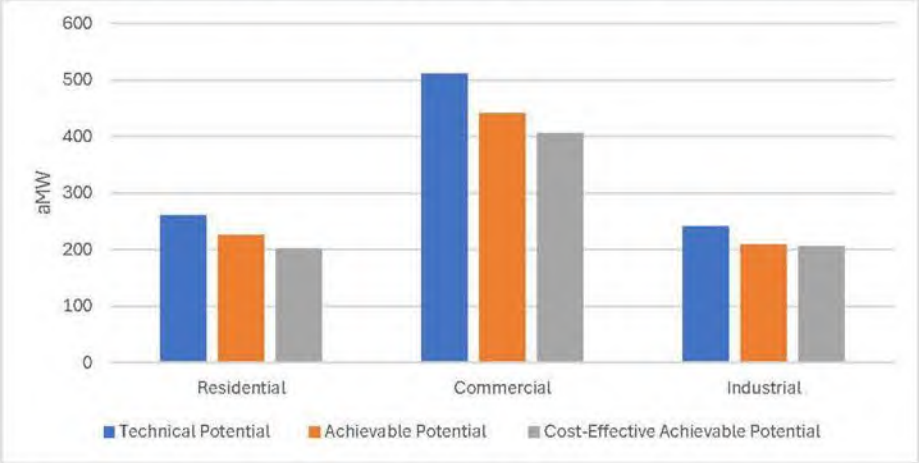


Figure 2 links actual historic savings going back to 2014 to the Energy Trust claimed savings projection for the 2025 IRP. It also compares the 2025 IRP forecast to the 2023 IRP forecast.

[2] All energy described in this report is measured at the generator.
[3] Includes 47.5 aMW of market transformation savings that Energy Trust will not claim resulting from residential and commercial lighting standards going into effect.

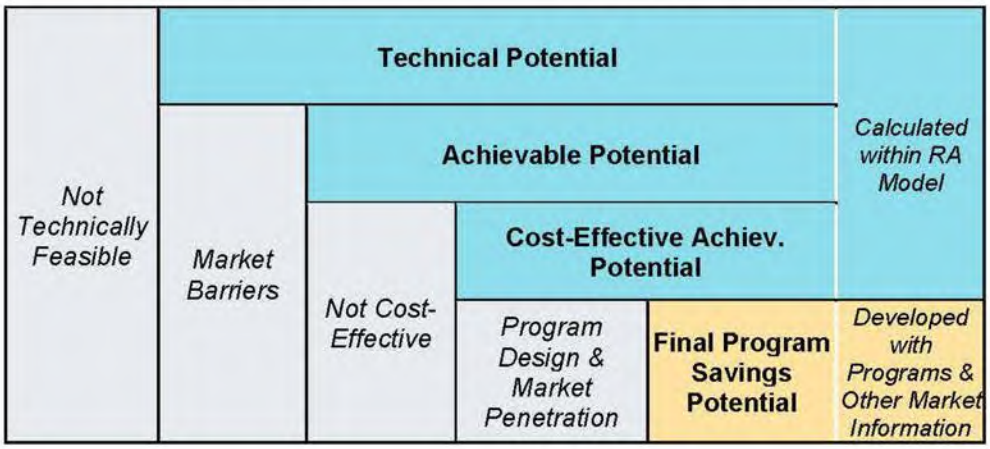
Figure 2 - Annual Savings Projection Comparison for 2023 and 2025 IRPs, with Actual savings since 2014

Energy Trust 20-Year Forecast Methodology

20-Year Forecast Overview

Energy Trust developed a 20-year DSM resource forecast for PGE using Energy Trust's RA Model to identify the total 20-year cost-effective modeled energy efficiency savings potential, which is 'deployed' exogenously of the model to provide an estimate of the final savings forecast. There are four types of potential that are calculated to develop the final savings potential estimate, which are shown in Figure 3 and discussed in greater detail in the sections below.

Figure 3 – Types of Potential Calculated in 20-year Forecast Determination

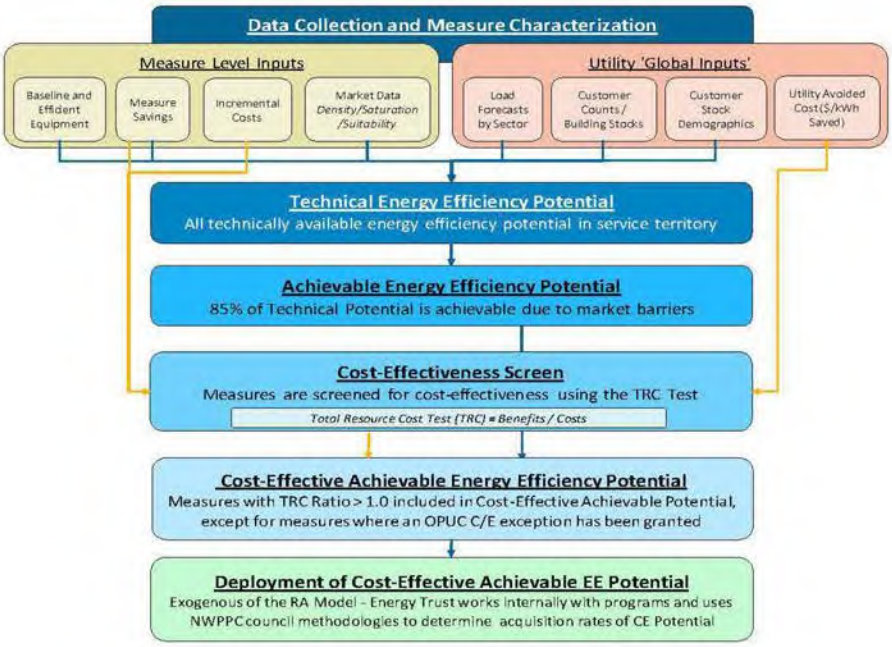


The RA Model utilizes the modeling platform Analytica®[4], an object-flow based modeling platform that is designed to visually show how different objects and parts of the model interrelate and flow throughout the modeling process. The model utilizes multidimensional tables and arrays to compute large, complex datasets in a relatively simple user interface. Energy Trust then deploys this cost-effective achievable potential exogenously to the RA model into an annual energy savings projection based on past program experience, knowledge of current and developing markets, and future codes and standards.

20-Year Forecast Detailed Methodology

Energy Trust's 20-year forecast for DSM savings follows six overarching steps from initial calculations to deployed energy savings, as shown in Figure 4. The first five steps in the varying shades of blue nodes - Data Collection and Measure Characterization to Cost-Effective Achievable Energy Efficiency Potential - are calculated within Energy Trust's RA Model. This results in the total cost-effective potential that is achievable over the 20-year forecast. The actual deployment of these savings (the acquisition percentage of the total potential each year, represented in the green node of the flow chart) is done exogenously of the RA model. The remainder of this section provides further detail on each of the steps shown below.

Figure 4 - Energy Trust's 20-Year DSM Forecast Determination Flow Chart



[4] http://www.lumina.com/why-analytica/what-is-analytica1/

1. Data Collection and Measure Characterization

The first step of the modeling process is to identify and characterize a list of measures to include in the model, as well as receive and format utility global inputs for use in the model. Energy Trust compiles a list of commercially available and emerging technology measures for residential, commercial, industrial and agricultural applications installed in new or existing structures. The list of measures is meant to reflect the full suite of measures offered by Energy Trust, plus a spectrum of emerging technologies.[5] Simultaneous to this effort, Energy Trust collects necessary data from the utility to run the model and scale the measure level savings to a given service territory (known as 'global inputs').

- ***Measure Level Inputs:***
  Once the measures to include in the model have been identified, they must be characterized to determine their savings potential and cost-effectiveness. The characterization inputs are determined through a combination of Energy Trust primary data analysis, regional secondary sources[6], and engineering analysis. There are over 30 measure level inputs that feed into the model, but on a high level, the inputs are put into the following categories:
  1. ***Measure Definition and Equipment Identification***: This is the definition of the efficient equipment and the baseline equipment it is replacing (e.g. a ductless mini-split heat pump replacing residential electric resistance space heat). A measure's replacement type is also determined in this step – Retrofit (RET), Replace on Burnout (ROB), or New Construction (NEW).
  2. ***Measure Savings:*** the kWh or therms savings associated with an efficient measure calculated by comparing the baseline and efficient measure consumptions.
  3. ***Incremental Costs:*** The incremental cost of an efficient measure over the baseline. The definition of incremental cost depends upon the replacement type of the measure. If a measure is a RET measure, the incremental cost of a measure is the full cost of the equipment and installation. If the measure is a ROB or NEW measure, the incremental cost of the measure is the difference between the cost of the efficient measure and the cost of the baseline measure.
  4. ***Market Data:*** Market data of a measure includes the density, saturation, and suitability of a measure. A density is the number of measure units that can be installed per scaling basis (e.g. the average number of showers per home for showerhead measures). The saturation is the average saturation of the density that is already efficient (e.g. 50% of the showers already have a low flow showerhead). Suitability of a measure is a percentage input to represent the percent of the density that the efficient measure is suitable to be installed in. These data inputs are all generally derived from regional market data sources such as NEEA's Residential and Commercial Building Stock Assessments (RBSA and CBSA).

[5] An emerging technology is defined as technology that is not yet commercially available but is in some stage of development with a reasonable chance of becoming commercially available within a 20-year timeframe. The model is capable of quantifying costs, potential, and risks associated with uncertain, but high-saving emerging technology measures. The savings from emerging technology measures are reduced by a risk-adjustment factor based on what stage of development the technology is in. The working concept is that the incremental risk-adjusted savings from emerging technology measures will result in a reasonable amount of savings over standard measures for those few technologies that eventually come to market without having to try and pick winners and losers.

[6] Secondary Regional Data sources include: The Northwest Power Planning Council (NWPPC), the Regional Technical Forum (the technical arm of the NWPPC), and market reports such as NEEA's Residential and Commercial Building Stock Assessments (RBSA and CBSA)

- ***Utility Global Inputs:***

  The RA Model requires several utility level inputs to create the DSM forecast. These inputs include:

  1. ***Customer and Load Forecasts:*** These inputs are essential to scale the measure level savings to a utility service territory. For example, residential measures are characterized on a scaling basis 'per home', so the measure densities are calculated as the number of measures per home. The model then takes the number of homes that PGE serves currently and the forecasted number of homes to scale the measure level potential to their entire service territory.
  2. ***Customer Stock Demographics:*** These data points are utility specific and identify the percentage of stock that utilize different heating fuels for both space heating and water heating. The RA Model uses these inputs to segment the total stocks to the stocks that are applicable to a measure (e.g. gas storage water heaters are only applicable to customers that have gas water heat).
  3. ***Utility Avoided Costs***[7]***:*** Avoided costs are the net present value of avoided energy purchases and avoided system costs that result from energy efficiency savings represented as $s per kWh saved. These values are provided by PGE based generally upon the avoided costs generated by PGE as an outcome of their IRP modeling. Avoided costs are the primary 'benefit' of energy efficiency in the cost-effectiveness screen.

2. Calculate Technical Energy Efficiency Potential

Once measures have been characterized and utility data loaded into the model, the next step is to determine the technical potential of energy that could be saved. Technical potential is defined as the total potential of a measure in the service territory that could be achieved regardless of market barriers, representing the maximum potential energy savings available. The model calculates technical potential by multiplying the number of applicable units for a measure in the service territory by the measure's savings. The model determines the total number of applicable units for a measure utilizing several of the measure level and utility inputs referenced above:

Total applicable units =	*Measure Density * Baseline Saturation * Suitability Factor * Heat Fuel Multipliers (if applicable) * Total Utility Stock (e.g. # of homes)*
Technical Potential =	*Total Applicable Units * Measure Savings*

The measure level technical potential is then summed up to show the total technical potential across all sectors. This savings potential does not account for the various market barriers that will limit a 100 percent adoption rate.

3. Calculate Achievable Energy Efficiency Potential

Achievable potential is simply a reduction to the technical potential based on each measure's achievability assumption rate, to account for market barriers that prevent total adoption of all cost-effective measures. Historically the achievable potential was defined as 85 percent of the technical potential. The Northwest Power and Conservation Council (NWPCC) updated the achievability assumption for certain measures in the most recent power plan, and Energy Trust has aligned the

[7] Energy Trust uses a single electric blended avoided costs for its programs, measure development and benefit/cost metrics.

RA model with these assumptions. Many measures still have 85 percent achievability while market transformation and codes and standards are assumed to be closer to 100 percent achievability.

Achievable Potential =	*Technical Potential * achievability %*

4. Determine Cost-effectiveness of Measures using TRC Screen

The RA Model screens all DSM measures in every year of the forecast horizon using the Total Resource Cost (TRC) test, a benefit-cost ratio (BCR) that measures the cost-effectiveness of the investment being made in an efficiency measure. This test evaluates the total present value of benefits attributable to the measure divided by the total present value of all costs. A TRC test value equal to or greater than 1.0 means the value of benefits is equal to or exceeds the costs of the measure and is therefore cost-effective and contributes to the total amount of cost-effective potential. The TRC is expressed formulaically as follows:

TRC = Present Value of Benefits / Present Value of Costs

Where *the Present Value of Benefits* includes the sum of the following two components:

a) Avoided Costs: The present value of electricity saved over the life of the measure, as determined by the total kWh saved multiplied by PGE's avoided cost per kWh. The net present-value of these benefits is calculated based on the measure's expected lifespan using PGE's discount rate.
b) Non-energy benefits are also included when present and quantifiable by a reasonable and practical method (e.g. water savings from low-flow showerheads, operations and maintenance (O&M) cost reductions from advanced controls).

Where *the Present Value of Costs* includes:

a) Total participant incremental cost

The cost-effectiveness screen is a critical component for Energy Trust modeling and program planning because Energy Trust is only allowed to incentivize cost-effective measures, unless an exception has been granted by the OPUC. Energy Trust is governed by policy directives to obtain all reasonably attainable cost-effective potential[8].

5. Quantify the Cost-Effective Achievable Energy Efficiency Potential

The RA Model's final output of potential is the quantified cost-effective achievable potential. If a measure passes the TRC test described above, then the *achievable savings* (designated percentage of technical potential) from this measure is included in the cost-effective achievable potential. If the measure does not pass the TRC test above, the measure is not included in the cost-effective achievable potential. However, the cost-effectiveness screen can be overridden for some measures under three specific conditions:

1) The OPUC has granted an exception to offer non-cost-effective measures under strict conditions or,

[8] As directed in OPUC docket UM-551 and 2017 ORS 757.054

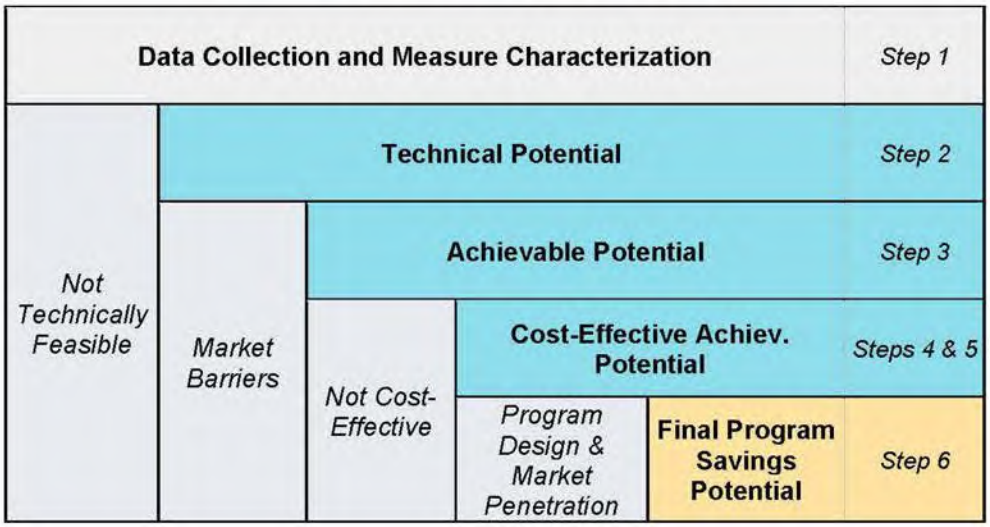
2) When the measure isn't cost-effective using utility specific avoided costs, but the measure is cost-effective when using blended electric avoided costs for all of the electric utilities Energy Trust serves and is therefore offered by Energy Trust programs.

6. Deployment of Cost-Effective Achievable Energy Efficiency Potential

After the model determines the 20-year cost-effective achievable potential, Energy Trust develops a savings projection based on past program experience, knowledge of current and developing markets, and future codes and standards. The savings projection is a 20-year forecast of energy savings that is projected to result in a reduction of load on PGE's system. This savings forecast includes savings from program activity for existing measures and emerging technologies, expected savings from market transformation efforts that drive improvements in codes and standards.

Figure 5 below reiterates the types of potential shown in Figure 3, and how the steps described above and in Figure 4 fit together.

Figure 5 - The Progression to Program Savings Projections



Forecast Results

Forecast results will be shown in several different sections, as the RA model has different output capabilities that are applied to project energy savings potential in a variety of different views, including by segment, end use, and in supply curves. The final savings projection is provided by segment and program delivery type. The RA Model produces results by type of potential, as well as several other useful outputs, including a supply curve based on the levelized cost of energy efficiency measures. This section discusses the overall model results by potential type and provides an overview of the supply curve.

Forecasted Savings by Sector

Table 1 summarizes the technical, achievable, and cost-effective achievable potential for PGE's system in Oregon. The savings in the table represent the total 20-year cumulative energy savings potential identified in the RA Model for each of the three respective types of potential identified in Figure 3 and Figure 5, prior to deployment of the savings into the final savings projection.

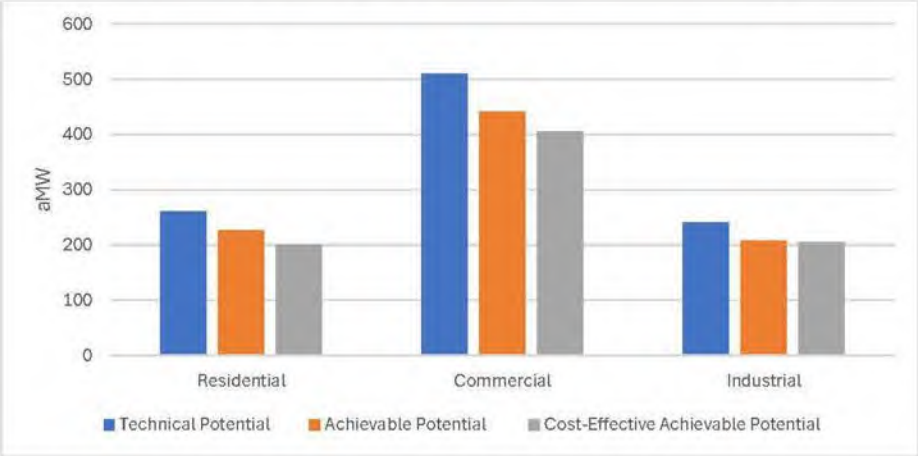
Table 1 - Summary of Cumulative Modeled Savings Potential - 2024–2043

Sector	Technical Potential (aMW)	Achievable Potential (aMW)	Cost-Effective Achievable Potential (aMW)
Residential	261	226	202
Commercial	511	442	406
Industrial	241	209	206
Total	**1,012**	**876**	**813**

Figure 6 shows cumulative forecasted savings potential across the three sectors Energy Trust serves, as well as the type of potential identified in PGE's service territory.

The Commercial sector represents the largest source of efficiency potential within PGE's territory. 86% of the industrial technical potential is cost-effective, while the residential and commercial sectors cost-effective achievable potential are 77% and 80% of technical potential respectively.

Figure 6 - Savings Potential by Sector – Cumulative 2024–2043

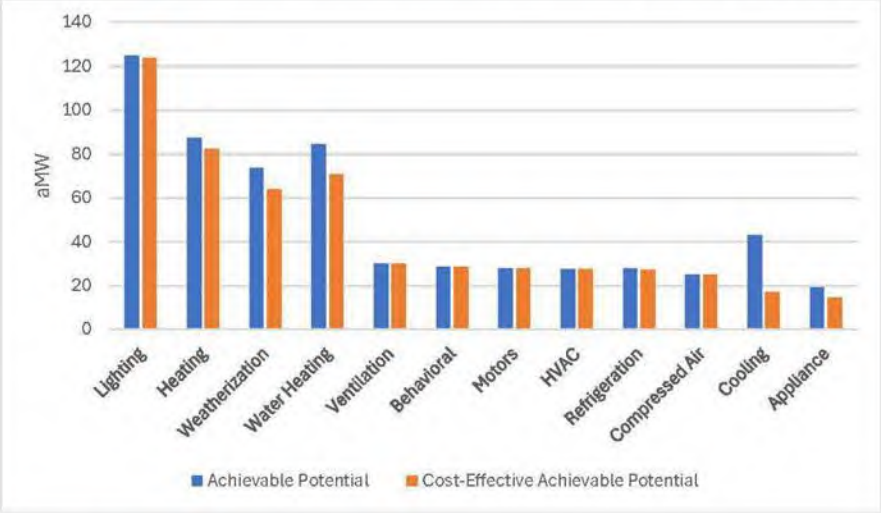


Cost-Effective Achievable Savings by End-Use

Figure 7 below provides a breakdown of PGE's 20-year cost-effective DSM savings potential by major end use. Some potential that doesn't map to a single end-use is omitted from this figure such as general new construction whole building measures and custom industrial and large commercial measures.

Lighting, heating, weatherization and water heating are the end-uses with the largest energy savings potential in PGE territory. Most of the lighting and heating potential is cost effective while a lower share of weatherization, water heating and cooling past TRC test in the model.

Figure 7 – 20-year Cost-Effective Achievable Cumulative Potential by End Use



Contribution of Emerging Technologies

As mentioned earlier in this report, Energy Trust includes a suite of emerging technologies (ETs) in its model. The emerging technologies included in the model are listed in Table 2.

Table 2 - Emerging Technologies Included in the Model that are pertinent for PGE

Residential	Commercial	Industrial
• Window Attachments •Thin Triple Pane Windows • Advanced Insulation • Heat Pump Dryers • Split System CO2 Heat Pump Water Heater • Smart Line Voltage Thermostats	• Zero Net Energy Ready Construction • Hybrid Indirect-Direct Evaporative Cooler • Advanced Refrigeration Controls • Refrigeration Anti-Fogging Film • Advanced Window Technologies	• CO2 Refrigeration • Industrial Heat Pumps • Advanced Wall Insulation

Energy Trust recognizes that emerging technologies are inherently uncertain and utilizes a risk factor to hedge against that risk. The risk factor for each emerging technology is used to characterize the inherent uncertainty in the ability for ETs to produce reliable future savings. This risk factor was determined based on qualitative metrics of:

- Market risk

- Technical risk
- Data source risk

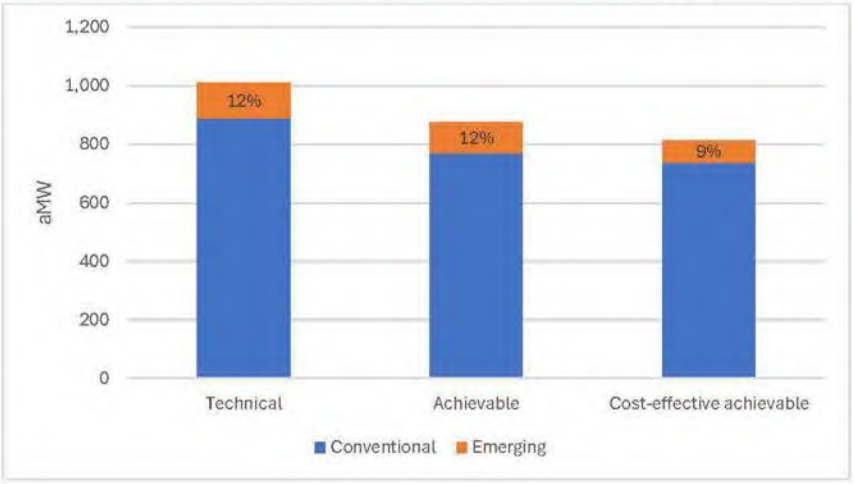
The framework for assigning the risk factor is shown in Table 3. Each ET was assessed within each risk category and a total weighted score was then calculated. Well-established and researched technologies have lower risk factors while nascent, unevaluated technologies (e.g., CO2 heat pump water heaters) have higher risk factors. This risk factor was then used as a multiplier of the incremental savings potential of the measure.

Table 3 - Emerging Technology Risk Factor Score Card

	ET Risk Factor				
Risk Category	10%	30%	50%	70%	90%
Market Risk (25% weighting)	**High Risk:** • Requires new/changed business model • Start-up, or small manufacturer • Significant changes to infrastructure • Requires training of contractors. Consumer acceptance barriers exist			**Low Risk:** • Trained contractors • Established business models • Already in U.S. Market • Manufacturer committed to commercialization	
Technical Risk (25% weighting)	**High Risk:** Prototype in first field tests. A single or unknown approach	Low volume manufacturer. Limited experience	New product with broad commercial appeal	Proven technology in different application or different region	**Low Risk:** Proven technology in target application. Multiple potentially viable approaches.
Data Source Risk (50% weighting)	**High Risk:** Based only on manufacturer claims	Manufacturer case studies	Engineering assessment or lab test	Third party case study (real world installation)	**Low Risk:** Evaluation results or multiple third-party case studies

Figure 8 below shows the amount of emerging technology savings within each type of DSM cumulative potential. While emerging technologies make up about 21% of the technical potential, once the cost-effectiveness screen is applied, the relative share of emerging technologies drops to about 13% of total cost-effective achievable potential. This is because many of these technologies are still in early stages of development and are quite expensive. Though Energy Trust includes factors to account for forecasted decreases in cost and increased savings from these technologies over time, some are still never cost-effective over the planning horizon or do not become cost-effective until later years.

Figure 8 – Cumulative Contribution of Emerging Technologies by Potential Type



Cost-Effective Override Effect

Table 4 shows the savings potential in the RA model that was added by employing the cost-effective override option. As discussed in the methodology section, the cost-effective override option forces non-cost-effective measures into the cost-effective potential results and is used when a measure meets one of the following three criteria:

1. A measure is offered under an OPUC exception.
2. When the measure isn't cost-effective using PGE-specific avoided costs but the measure is cost-effective when using blended electric avoided costs for all of the electric utilities Energy Trust serves and is therefore offered by Energy Trust programs.
3. The measure is not cost-effective in our model, but may appear cost-effective in program settings, where costs are combined with other measures or highly variable from project to project[9].

[9] Some measures can have high degrees of variations in savings and costs. If a measure is cost-effective in the RA model then all savings attributable to the measure are included. Conversely, if a measure is not cost-effective in the RA model then zero savings will be shown in the model. While costs are updated frequently to reflect changing markets there may be instances where some instances of installation are cost-effective and others are not. Many of these types of projects are screened individually for cost-effectiveness in Energy Trust's custom program offerings.

Table 4 - Cumulative Cost-Effective Potential (2024-2043) due to Cost-Effectiveness Override (aMW)

Sector	Total Cumulative Cost-Effective Potential With CE Override	Total Cumulative Cost-Effective Potential No CE Override	Difference
Residential	202	132	69
Commercial	406	406	-
Industrial	813	206	-
Total DSM:	**813**	**744**	**69**

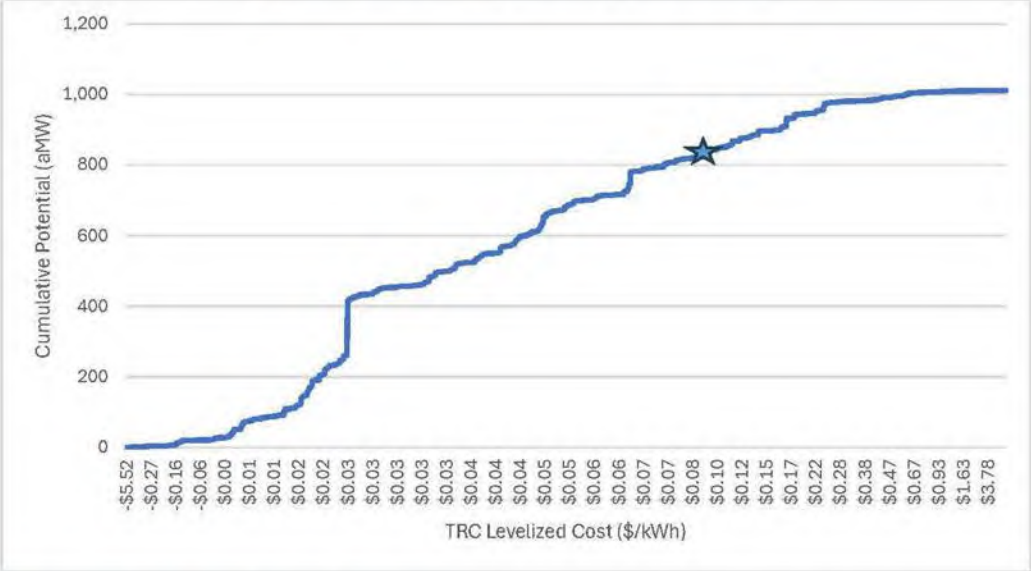
In this IRP, 9% of the cost-effective potential identified by the model is due to the use of the cost-effective override for measures. This is a higher share than in previous IRPs and is attributable to the OPUC cost-effectiveness exception for manufactured homes early replacement (14 aMW of the 69 aMW shown in Table 4). This measure generates a lot of potential due to the stock of existing manufactured homes in PGE territory, however this measure receives a low ramp-rate in the deployment process to account for market barriers and qualification criteria of homes and not all potential is deployed. Measures under exception make up 7% of the cost-effective achievable potential without the override applied to manufactured homes early replacement.

Supply Curves and Levelized Cost Outputs

An additional output of the RA Model is a resource supply curve developed from the levelized cost of energy of each measure. The supply curve graphically depicts the total potential in average megawatts that could be saved at various costs for all measures. The levelized cost for each measure is determined by calculating the present value of the total incremental cost of the measure over its economic life, per kWh of energy savings ($/kWh saved). The levelized cost calculation starts with the customer's incremental cost of a given measure. The total cost is amortized over an estimated measure lifetime using the PGE's discount rate provided to Energy Trust. The annualized measure cost is then divided by the annual kWh savings. Some measures have negative levelized costs because non-energy benefits amortized over the life of the measure are greater than the total cost of the measure over the same period.

Figure 9 below shows the supply curve developed for this IRP that can be used for comparing demand-side and supply-side resources. The star on the graph shows roughly the cutoff where savings become non-cost-effective, although some savings above the star are included due to cost-effective override.

Figure 9 – Electric Supply Curve ($ per kWh saved)



Deployed Results – Final Savings Projection

The results of the final savings projection show that PGE can save 171.7 aMW in the next five years from 2025 to 2029 and over 675 aMW by 2043. This represents a 16.5 percent cumulative load reduction by 2043[10] and is an average of 1.1 percent incremental annual load reduction. The cumulative final savings projection is shown in Table 5 compared to the technical, achievable and cost-effective achievable potential.

Table 5 - 20-Year Cumulative savings potential by type, including final savings projection (aMW)

Sector	Technical Potential	Achievable Potential	Cost-Effective Achievable Potential	Final Savings Projection[11]
Residential	261	226	202	151
Commercial	511	442	406	260
Industrial	241	209	206	203
Exogenous Savings[12]				62
Total	**1,012**	**876**	**813**	**675**

[10] Cumulative savings assumes customers will continue to purchase equipment of equal or higher efficiency equipment after the measure reaches the end of its useful life and therefore savings in this instance are assumed to persist in future years.

[11] The final savings projection includes market transformation lighting savings that will not be claimed by Energy Trust but are expected to come off PGE's system. These savings account for 44.7 aMW of the combined commercial and industrial final savings projections and 2.9 aMW of the residential final savings projection.

[12] Exogenous savings are calculated outside of the RA model and consist of commercial and residential prior codes, industrial large projects and residential electrification.

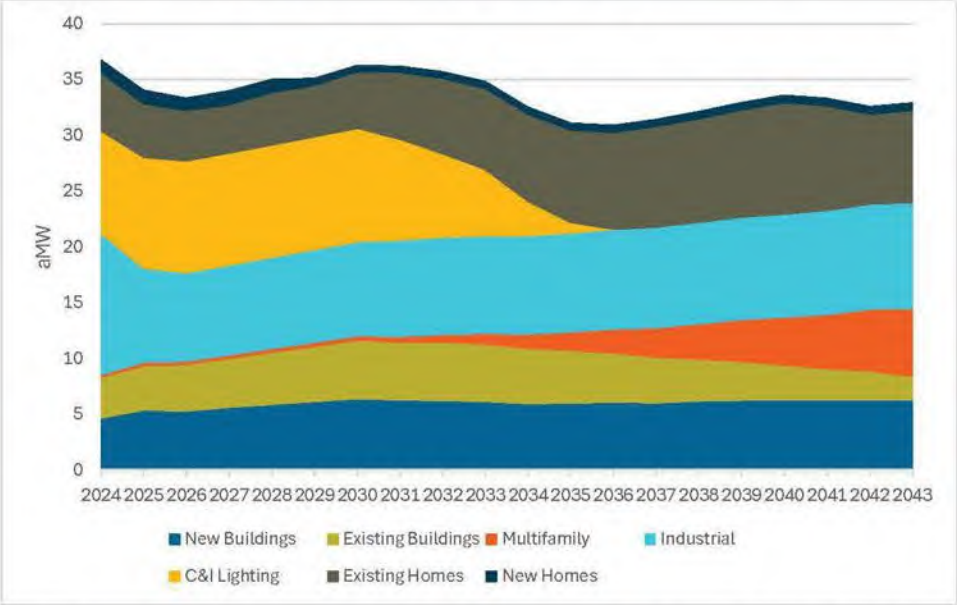
Energy Trust's general modeling principle is to deploy 100% of retrofit cost-effective achievable potential or ramp to 100% of cost-effective achievable potential for replacement and new construction measures consistent with Northwest Power and Conservation Council ramp rate methodology. However, certain measures have unique market barriers, uncertainties, or are early in their market adoption trajectory limiting their deployment. As such, the final deployed savings projections in Table 5 are a subset of the cost-effective achievable potential. This is most notable for the residential and commercial sectors which have a higher share of these measures where 100% deployment of cost-effective achievable potential is not feasible. There are several reasons why 100% acquisition is unrealistic, including:

1) "Lost Opportunity Measures" – Measures that are meant to replace failed equipment (ROB) or new construction measures (NEW) are considered lost opportunity measures because programs have one opportunity to influence the installation of efficient equipment over code baseline when the existing equipment fails or when the new building is built. This is because these measures must be installed at that specific point in time, and if a program administrator misses the opportunity to influence the installation of more efficient equipment, the opportunity is lost until the equipment fails again. Energy Trust expects that most of these opportunities will be met in later years as efficient equipment becomes more readily adopted. However, in early years, the level of acquisition for these opportunities is smaller and ramps higher as time progresses.
2) "Hard to Reach Measures" – some measures that show high savings potential are notoriously hard to reach. These include multifamily and shell measures.
3) The nascent and uncertain nature of emerging technologies limit their market adoption in the forecast horizon similar to #2 above.
4) New, comprehensive measures added to the RA model including New Buildings Custom Data Center and New Homes Manufactured Home Early Replacement – Custom Data Center savings are subject to modeling uncertainty. Energy Trust modeled their adoption using program expertise and achievements from past projects and, given the magnitude of load forecast, make up a large share of the commercial sector step down in Table 5. Similarly, the Manufactured Home Early Replacement measure calculates potential for a large share of manufactured homes in PGE territory, however it is unrealistic that 100% of homes will turn over in the forecast period given its relatively high cost and labor (note this measure is under OPUC exception).

Exogenous savings are calculated outside of the RA model because they are generally accounted for in market characterization assumptions (prior codes) or their baseline is present in the utility load forecast (residential electrification). Energy Trust models prior codes using a forecast from NEEA. The inclusion of Residential Electrification is new for this round of modeling and was calculated as incremental lost opportunity savings above PGE's electrification forecast and were deployed consistent with similar lost opportunity measure adoption. Finally, Energy Trust exogenously adds industrial large projects because those savings are not characterized by the measures included in the RA model. In total exogenous savings total 62 aMW and make up 9% of the final savings projection.

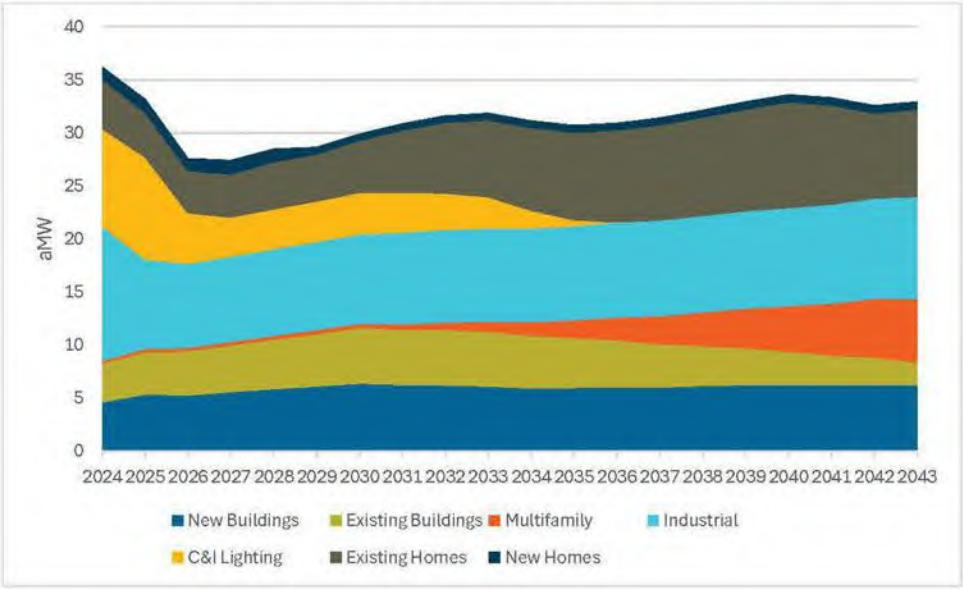
The final savings projection of 675 aMW in Table 5 represents 20-years of efficiency savings. The annual shape of the deployed efficiency forecast is shown in Figure 10 below.

Figure 10 – Annual Deployed Final Savings Potential



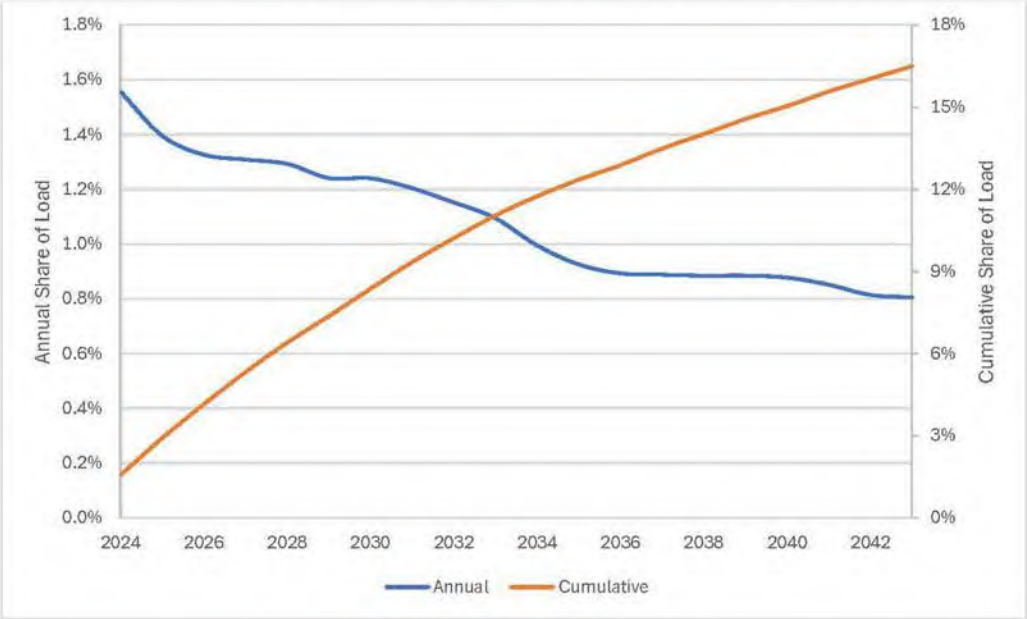
As previously noted, the final savings projection depicted in Figure 10 above includes 47.5 aMW of market transformation lighting savings that energy trust will not claim. Figure 11 below shows the annual efficiency forecast of Energy Trust claimed savings.

Figure 11 – Annual Deployed Energy Trust Claimed Savings Potential



Finally, Figure 12 shows the annual and cumulative savings as a percentage of PGE's load forecast. Annually, the savings as a percentage of load varies from about 0.8% at its lowest to 1.6% at its highest, as represented on the *left* Y-axis of the graph and the blue line. Cumulatively, the savings as a percentage of load builds to 16.5% by 2043, shown on the right Y-axis and the gold line.

Figure 12 – Annual Forecasted Savings as a Percentage of Annual Load Forecast



Deployed Results – Peak Day Results

Ongoing regional emphasis on peak and capacity management and an OPUC docket focused on electric utility Distribution System Planning (OPUC docket UM 2005) has resulted in continued interest in the contribution energy efficiency can make to managing electric utility loads. Additionally, the OPUC has directed Energy Trust to report peak impacts in the appendices of our annual report beginning in 2017[13].

Peak hour factors are the percentage of annual energy savings that occur during peak hours over the course of a year. Energy Trust calculates peak demand factors using Equation 1, where load factors and coincidence factors being derived from the NWPCC library of load profiles.

Equation 1 – Calculation of Peak Factors from Load and Coincidence Factors

$$\textit{Peak factor} = (1\ \textit{yr}/8760) * \textit{Load Factor} * \textit{Coincidence Factor}$$

Figure 11 below shows the annual, deployed peak day savings potential based upon the results of the 20-year forecast. Each measure analyzed is assigned a load shape and the appropriate peak factor is

[13] For the 2023 version of this report see Appendix 9 of Energy Trust's "*2023 Annual Report to the Oregon Public Utility Commission & Energy Trust Board of Directors*" available at https://www.energytrust.org/wp-content/uploads/2024/04/Energy-Trust-of-Oregon-2023-Annual-Report.pdf

applied to the annual savings to calculate the overall DSM contribution to peak day capacity. Cumulatively, this is equal to 1,980 MW[14], as shown in Table 6 below.

Figure 11 - Annual Deployed Peak Savings Contribution by Season

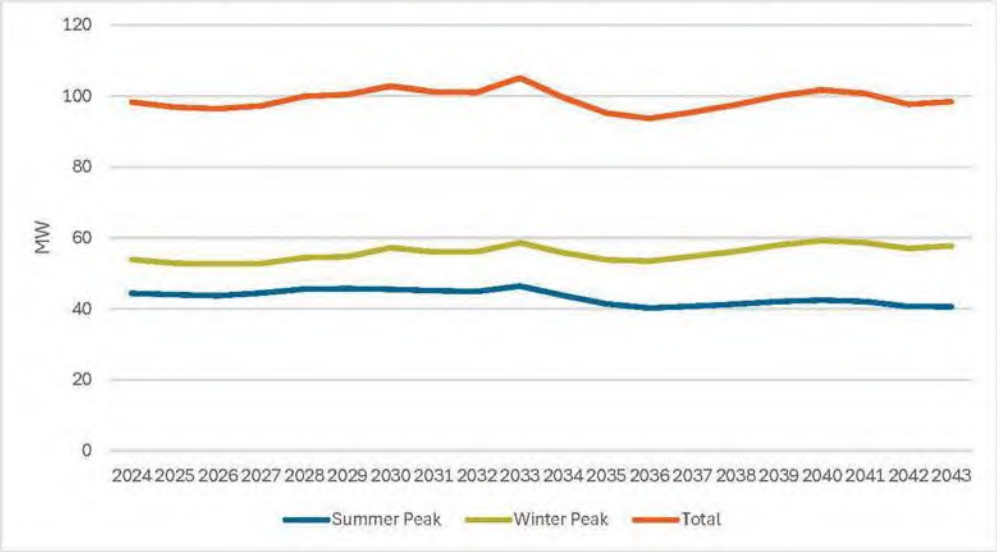


Table 6 - Cumulative Deployed Peak Savings Contribution by Sector

Sector	Cumulative Peak Savings (MW)	% of Overall Peak Savings
Residential	797	40%
Commercial	643	32%
Industrial	540	27%
Total	1,980	

Non-Cost-Effective Energy Efficiency

Starting in 2023, PGE requested that Energy Trust submit savings and levelized cost data from measures that did not pass the TRC cost-effectiveness screen in the Energy Trust RA model. This allows PGE to compare efficiency to supply side resources where the total resource cost of efficiency exceeds benefits calculated by utility submitted avoided costs. This modeling could highlight areas of value in addition to what is quantified in the UM 1893 avoided costs docket. This analysis is completed by PGE and the results are detailed in their IRP report. Summary values for the non-cost-effective efficiency submitted

[14] Peak results do not include energy savings from exogenous categories.

by Energy Trust are shown below in Table 7. For the 2025 IRP analysis, these savings total 75.1 aMW at a weighted average levelized cost[15] of $0.401/kWh.

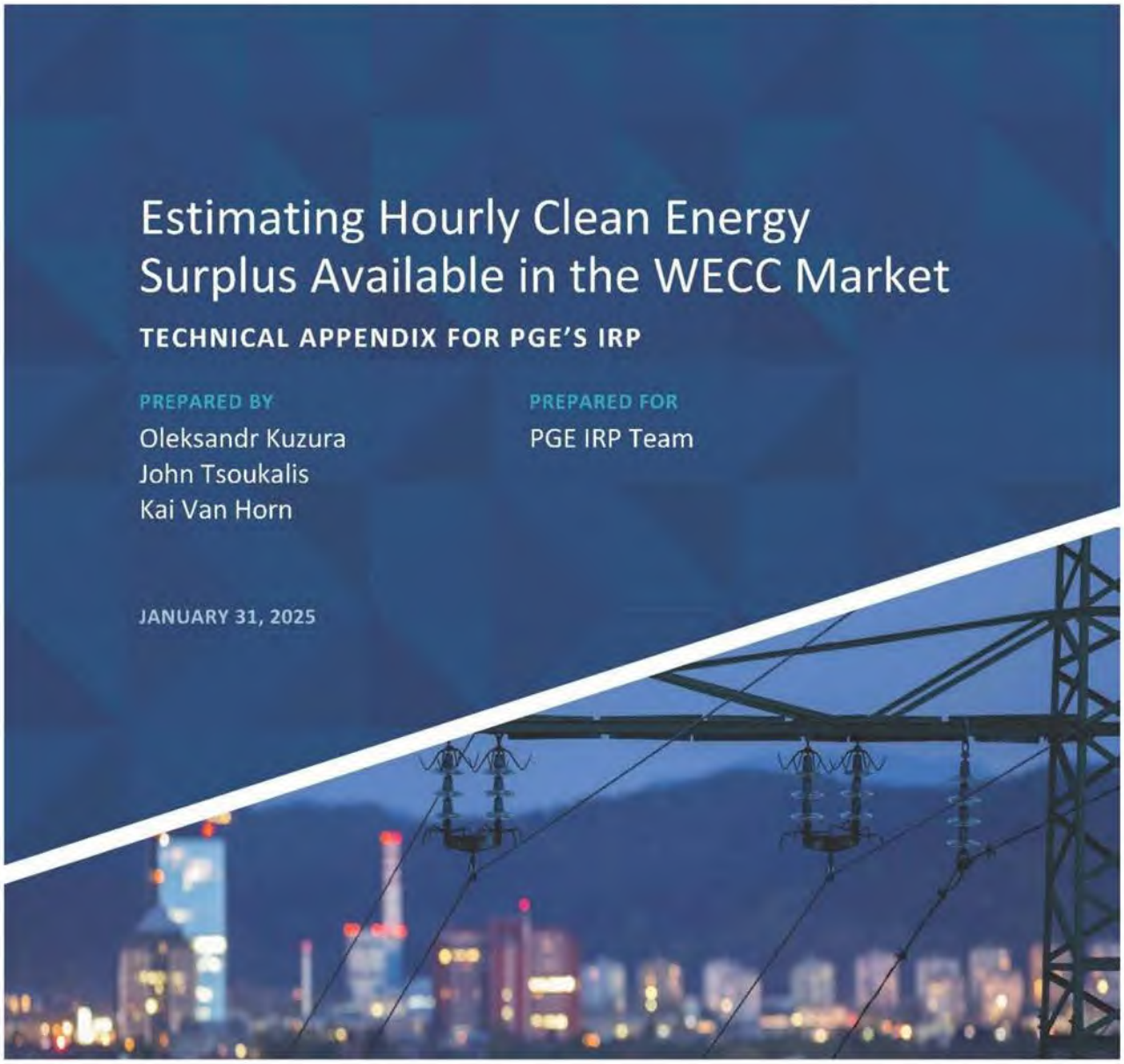
Table 7 – 20-year Non-Cost-Effective Efficiency Potential

Sector	Non-Cost-Effective Achievable Potential (aMW)[16]	Weighted Average Levelized Cost ($/kWh)
Residential	32.6	$0.406
Commercial	40.1	$0.412
Industrial	2.4	$0.149
Total	**75.1**	**$0.401**

[15] This levelized cost represents the total resource cost, levelized over measure life ($/kWh) plus a 31% administrative cost adder.

[16] The values in this column do not exactly match the difference between Achievable Potential and Cost-Effective Achievable Potential in Table 5 for several reasons including substitution between competing measures, cost-effective override, and the timing of discretionary measures on the margin of cost-effectiveness.

Appendix F Market for non-emitting energy



Brattle

PGE

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I. Introduction And Background

The Oregon Public Utility Commission (OPUC) directed Portland General Electric (PGE) to adopt hourly accounting of its clean energy position and the associated greenhouse gas (GHG) implications in its 2025 Clean Energy Plan (CEP) and Integrated Resource Plan (IRP) update. This directive was issued in Docket LC 80, in which OPUC Staff declined to acknowledge PGE's 2023 CEP due to concerns about PGE's ability to procure clean energy from the market. Specifically, PGE's portfolio was forecasted to be long on clean energy during shoulder seasons and short on clean energy during peak hours, matching regional supply trends across the Western Electricity Coordinating Council (WECC) territory. OPUC Staff and stakeholders raised concerns about PGE's assumption that clean energy would be equally available year-round, noting that supply could be limited at times and might also incur a premium cost to purchase.

The Brattle team (hereby "we") was engaged by PGE to address the OPUC's request to develop and implement an hourly accounting methodology for estimating the availability and cost of purchasing clean energy. Developing this methodology required answering the following questions:

- In each hour, how much clean energy is available after accounting for resources committed to other GHG reductions for non-PGE entities in the WECC?
- What, if any, is the cost premium associated with procuring surplus clean energy in a given hour? How does that cost premium vary with available supply?

We developed the Excel-based Clean Energy Surplus Model (CESM) to estimate the hourly WECC-wide market availability of clean energy deliverable to PGE and the potential cost premiums it may incur. The CESM uses hourly results from PGE's AURORA IRP simulations and a curve capturing the relationship between clean energy surpluses and potential purchase premiums to produce an hourly time series of clean energy deliverable to PGE and the potential associated premiums. The CESM outputs are then used in PGE's calculation of its resource plans' annual GHG impacts.

This appendix describes the CESM framework, including key assumptions, data inputs, outputs, strengths, and areas for future improvements. It is organized into five sections. Section 0 provides a detailed step-by-step explanation of the CESM's surplus calculation framework.

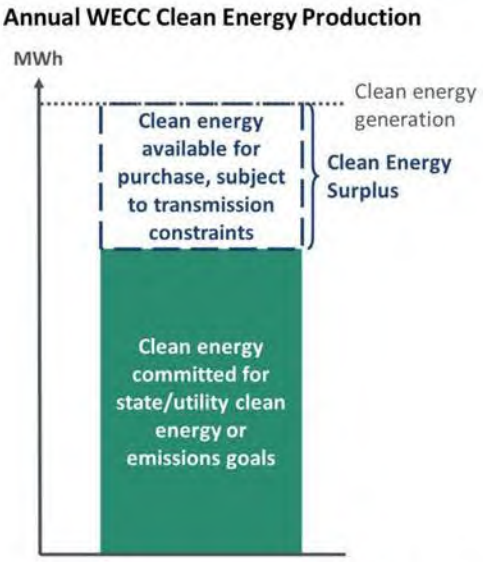
Section III details the CESM's premium calculation approach. Section IV summarizes the CESM's clean energy surplus and premium results for two AURORA simulations. Section V discusses the CESM's strengths and areas for potential future improvements.

II. Clean Energy Surplus Estimation Overview and Key Assumptions

Market purchases of clean energy could help offset PGE's emissions, but PGE's ability to access them depends on the WECC-wide clean energy supply, clean energy demand, and transmission available to PGE to import that energy. We define "clean energy surplus" (or "surplus") as the clean energy generated in the WECC beyond that which is needed to meet annual state-level clean energy requirements. Clean energy supply depends on the amount and types of generation resources available in each state and varies with regional and seasonal weather patterns and installed capacity. Clean energy demand depends on binding policy targets and voluntary goals set by states, municipalities, corporations, and other entities.[1] Transmission availability to PGE depends on the total transfer capability (TTC) over WECC transmission paths and the hourly utilization for regional trading. Figure 1 provides an illustration of the clean energy surplus as it relates to the overall availability of clean energy.

[1] We consider only binding state requirements in the CESM due to data availability constraints on voluntary targets.

FIGURE 1. ILLUSTRATIVE EXAMPLE OF CLEAN ENERGY SURPLUS



Using the CESM, we calculate hourly clean energy surpluses deliverable to PGE by:

1. Evaluating annual state-level clean energy surpluses or deficits,
2. Allocating annual regional surpluses or deficits to individual hours, and
3. Aggregating state-level results to the WECC-wide and regional levels,
4. Applying transmission constraints between PGE and the neighboring regions.

An overview of the CESM surplus calculation steps is given in Figure 2, with detailed descriptions of each step following.

FIGURE 2. SUMMARY OF CESM CLEAN ENERGY SURPLUS CALCULATION STEPS

1. Pre-Process and Aggregate Zonal AURORA Results to the State Level

PGE's IRP simulations in AURORA produce hourly load and generator dispatch results at a zonal level. The AURORA model divides the WECC into zones representing states, portions of states, and major transmission hubs as shown in Appendix C. In the CESM we assume states and transmission hubs with interconnected generation resources are the base geographic units to align with the geographic application of clean energy policy requirements. For utilities with multi-state service territories, generation and load are divided along state lines, consistent with the representation in the AURORA database.

We pre-process the AURORA results by aggregating sub-state results to the state level and combining all statewide generation into a single set of "clean" or "other" generation results. Appendix C contains a designation of resource types and a mapping of AURORA zones to states.

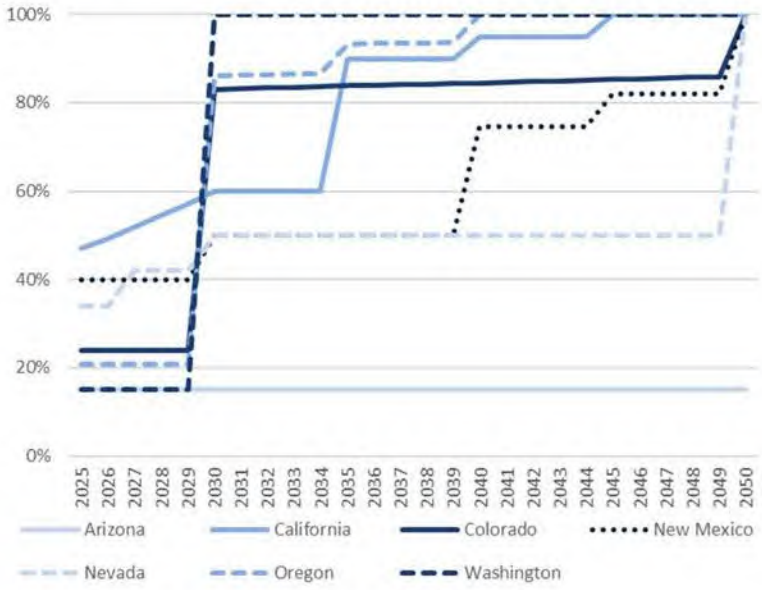
2. Calculate State-Level Annual Clean Energy Requirements

In the CESM, we assume only clean energy associated with legally binding state clean energy requirements is unavailable when calculating WECC-wide clean energy surplus. Voluntary targets from municipalities, corporations, and other entities have uncertain enforcement mechanisms. The CESM reflects additional demand from voluntary targets, such as corporate clean energy pledges or municipal clean energy programs through its calculation of purchase premiums described in Section III.

We calculate the total WECC-wide demand for clean energy by summing individual states' annual clean energy requirements. We calculate annual state-level clean energy requirements as the sum of each state's hourly electric demand multiplied by that state's percent-based clean energy requirement. State-level percent-based requirements are based on the LBNL's State Renewables Portfolio and Clean Electricity Standards database.[2] The CESM interpolates or extrapolates state-level targets set for specific years to derive annual clean energy targets for each of the PGE IRP study years, as needed. Figure 3 charts annual state-level targets included in the CESM, omitting data for states without policy targets.

[2] Lawrence Berkeley National Laboratory (LBNL). *U.S. State Renewables Portfolio & Clean Electricity Standards: 2023 Status Update*, 2023. Accessed online at https://emp.lbl.gov/publications/us-state-renewables-portfolio-clean.

FIGURE 3. STATE CLEAN ENERGY TARGETS INCLUDED IN THE CESM



3. Calculate State-Level Annual Clean Energy Surpluses or Deficits

The total volume of clean energy available to PGE for purchase depends on each state's annual clean energy generation surplus or deficit relative to its annual clean energy requirements. We assume that states prioritize meeting their annual clean energy requirements using in-state generation, and that any state-level clean energy generation in excess of state-level clean energy requirements would be available as surplus. On the other hand, any shortfalls in state-level clean energy generation relative to state-level targets reduce the total amount of clean energy surplus available WECC-wide, as we assume surpluses from other states fill requirement deficiencies before being offered to the market.

We calculate annual state-level clean energy surpluses or deficits as the difference between each state's annual clean energy policy targets and the total clean energy production that can be used to satisfy those requirements. In each hour, we assume that all clean energy generation up to a state's hourly load can be used to meet clean energy policy targets ("usable" clean energy). We assume that clean energy generation exceeding states' hourly loads would

be deemed surplus clean energy. We then calculate annual clean energy generation usable for meeting states' clean energy policy targets by summing usable clean energy generated across all hours of the year.

Next, we compare each state's annual usable clean energy generation to its annual clean energy targets. If a state's total annual clean energy generation is not enough to satisfy its annual clean energy requirements, that state is assumed to be in deficit and must rely on clean energy from other states to meet its targets. On the other hand, if a state's annual usable clean energy generation is greater than its annual clean energy requirements, that state is assumed to have an annual clean energy surplus.

4. Allocate State-Level Annual Surpluses or Deficits to Individual Hours

To calculate the hourly availability of clean energy WECC-wide and regionally, we next allocate states' gross annual clean energy surpluses or deficits to individual hours surplus availability. As a starting point, we assume that surpluses and deficits are proportional to hourly clean energy production and loads.

In the CESM we apply a heuristic to carry out this hourly allocation by assuming that states' surpluses or deficits are proportional to the difference between hourly clean energy production and demand. We implement this "proportional" approach in the CESM by deriving an annual surplus or deficit allocation factor.

For states with gross annual surplus clean energy production, we calculate the allocation factor as the difference between the state's total annual clean energy production and its total annual clean energy requirement. This factor is then applied to determine the portion of a state's hourly clean energy production that could be offered on the market. For example, a state with 100 MWh of annual clean energy production and 80 MWh of clean energy requirements would have an allocation factor of 20%. This means that the state can offer 20% of its annual clean energy production (20 MWh) and still have enough usable clean energy production to meet its annual clean energy targets (80 MWh). In an hour when the state produces 10 MWh of clean energy, it is assumed to offer 2 MWh on the market (20% of production in that hour) and keep 8 MWh (the remaining 80% of production in that hour) to count toward its own policy requirements.

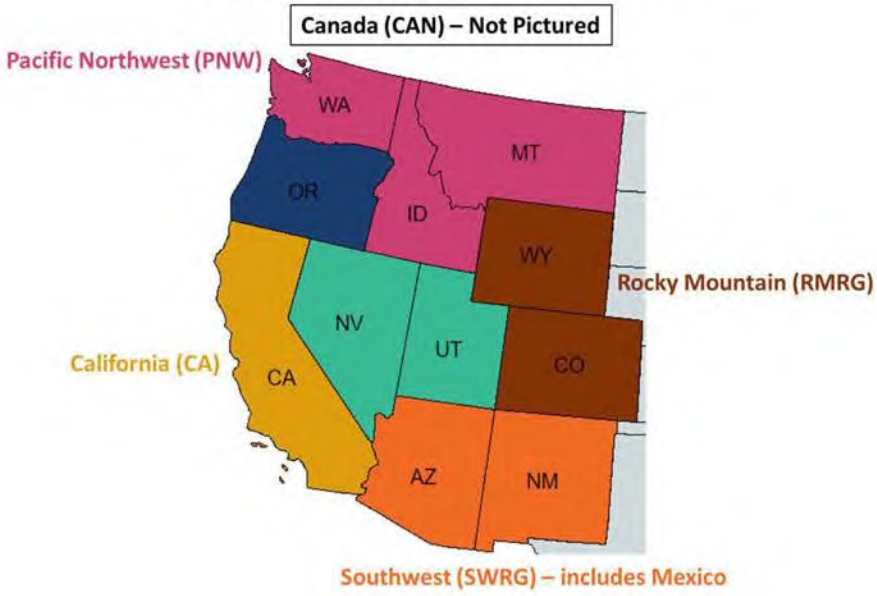
For states with gross annual deficits of clean energy, we calculate the allocation factor as the difference between the state's annual clean energy target and the state's total annual clean energy production. This allocation factor is then used to determine quantity of clean energy procurement the state would seek to procure on the market in each hour. For example, if a state's annual clean energy policy target is 100 MWh and its local annual clean energy production is 60 MWh, then the state's allocation factor would be 40%. In an hour when the state's load is 10 MWh and its local clean energy production is 8 MWh, the state would seek an additional 0.8 MWh of clean energy (40% of 2 MWh) to contribute to filling its annual deficit.

5. Aggregate Hourly State-Level Results to Regional and WECC-Wide Level

We use the CESM to calculate the WECC-wide hourly surplus or deficit by summing the hourly surpluses and deficits of each state. The Oregon-West (OR-WE) AURORA zone contains PGE and is omitted from this calculation to represent PGE's view of the WECC market.

We aggregate state-level results into regions based on states' transmission connectivity to facilitate data validation and later application of deliverability constraints (Figure 4). Assuming sufficient transmission availability among states within each region, the CESM calculates hourly regional surpluses and deficits by summing the hourly surpluses and deficits of the region's member states. For example, the proportional allocation method may suggest that Wyoming could have 10 MWh of clean energy to offer on the market the same hour that Colorado could seek to procure 5 MWh of clean energy to fill its deficit. Since these states comprise the RMRG region, the CESM would indicate a 5 MWh clean energy surplus in the RMRG region in this hour.

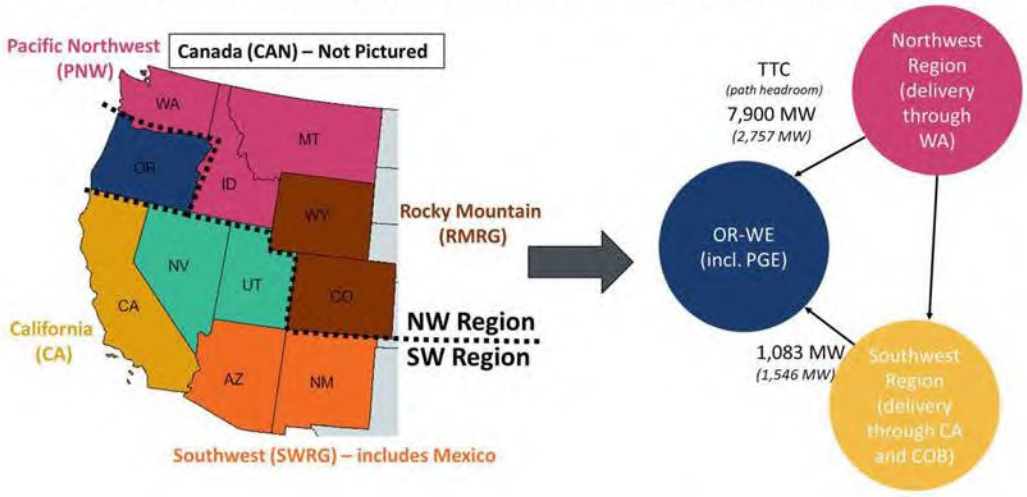
FIGURE 4. REGIONAL AGGREGATION IN THE CESM



6. Calculate Clean Energy Surplus Deliverable to PGE

We further limit the availability of clean energy surplus to PGE in the CESM based on available transmission headroom on the transmission paths connecting PGE to the rest of the system. To do so, we use the transmission path limits and power flow represented in the AURORA model between the OR-WE zone and the neighboring zones representing California, Washington, and the California-Oregon Border (COB) trading hub. For tractability in the CESM calculations, we aggregate the regions in Figure 4 into the Northwest and Southwest super-regions (Figure 5) and consider clean energy deliverability to PGE based on its transmission capacity and availability to these regions.

FIGURE 5. DIVISION OF WECC STATES INTO NORTHWEST AND SOUTHWEST REGIONS



We then calculate surplus *deliverable* to PGE in the Oregon-West zone in three steps:

1. **Balance Northwest and Southwest regional surpluses and deficits** by calculating the hourly surplus or deficit available in the Northwest and Southwest regions. This step uses a similar approach to that used for aggregating state-level results to the regional level as described in Step 5 above.

   In the CESM, we assume surplus transfers are unrestricted by transmission constraints within each super-region, except between the Rocky Mountain (RMRG) region and the rest of the Northwest. RMRG has a larger wind generation resource in Wyoming than it has transmission interconnectivity with the rest of the Northwest region. To reflect this in the CESM, we enforce a constraint between RMRG and the Pacific Northwest (PNW) region, balancing RMRG surpluses and deficits with the rest of the PNW. When RMRG surplus exceeds available headroom on the RMRG to PNW path, the rest of the RMRG surplus is assumed to be sent to the Southwest region. Any RMRG surplus beyond that which is deliverable to the Northwest and Southwest regions via available transmission headroom is assumed to be unavailable to PGE.

2. **Calculate available hourly transmission path headroom from the Northwest and Southwest regions to Oregon-West.** We calculate within the CESM the available headroom to Oregon-West based on the path ratings and hourly transmission utilization results from the AURORA model. For each transmission path, we calculate a net hourly flow by netting

out flows in the forward and reverse direction as defined in the AURORA inputs. To arrive at available headroom for the CESM, we then subtract the net flow from the path's TTC in each hour. In this initial version of the CESM, we assume no re-dispatch of storage or thermal resources to relieve congestion constraints or improve deliverability of clean energy to PGE at certain times of day. We calculate the total headroom from the Southwest region into OR-WE as the sum of the transmission headroom from California to OR-WE and from COB to OR-WE.

3. **Adjust Northwest and Southwest region surpluses for deliverability into OR-WE, accounting for transfers between the Northwest and Southwest regions.** We limit hourly transfers within the CESM from the Northwest and Southwest regions into OR-WE based on the hourly transmission headroom available into OR-WE. We additionally assume that surplus transfers can occur between the Northwest and Southwest regions as needed to ensure full utilization of transmission headroom into OR-WE. For example, if the Northwest region had 100 MWh of surplus but only 80 MW of transmission headroom available to OR-WE in some hour, then PGE could access only 80 MWh of surplus from the Northwest region in that hour. However, the CESM assumes those 20 MWh of surplus could be delivered to OR-WE via the Southwest region if there were enough transmission headroom available on the paths from the Northwest to the Southwest and from the Southwest to OR-WE.

III. Clean Energy Premium Estimation Approach

The CESM reflects an expectation that PGE may have to pay a premium to secure clean energy supplies when those supplies are relatively scarce.

We reflect this expectation in our calculations by estimating an hourly Clean Energy Premium, defined as the additional cost that PGE may have to pay beyond the energy price associated with the purchase of clean energy. Within the CESM we use a Clean Energy Premium Curve (CEPC) to translate hourly WECC-wide clean energy surpluses into hourly clean energy premiums. The CESM calculates the hourly Clean Energy Premium PGE may have to pay in three steps:

1. Create a WECC-wide CEPC for the simulation year

2. Calculate WECC-wide hourly Clean Energy Premiums
3. Implement PGE-specific Clean Energy Premium adjustments

Next, we discuss each of these steps in greater detail.

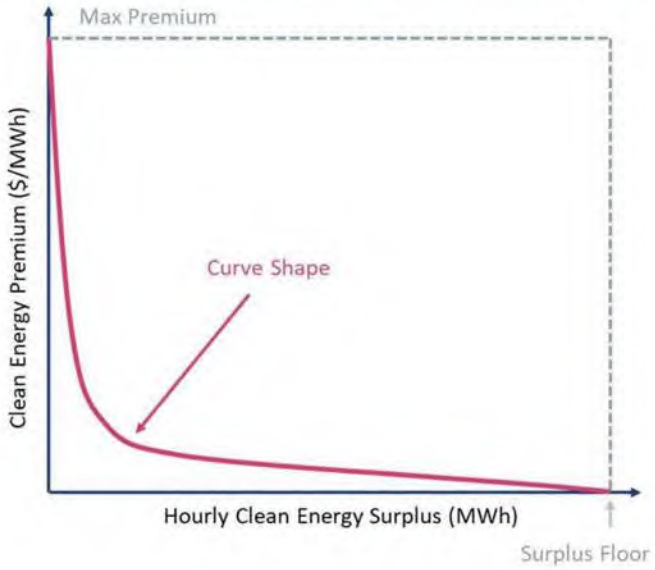
1. Create a WECC-Wide CEPC for the Simulation Year

The CEPC captures the impact of competition for scarce clean energy on the value of its clean energy attribute, broadly mimicking the price-quantity dynamics observed in other clean attribute markets. We define the CEPC separately for each model year using three parameters:

- **Curve shape** reflecting the relationship between the Clean Energy Premium and WECC-wide surplus quantity,
- **Max premium** related to the levelized cost of procuring clean energy from newly built capacity, in the case of PGE the cost of a new build wind resource, and
- **Surplus floor** threshold quantity above which the premium is assumed to be zero.

Figure 6 shows an illustrative CEPC with the above parameters labeled, followed by additional discussion of each parameter.

FIGURE 6. CLEAN ENERGY PREMIUM CURVE PARAMETRIZATION



CEPC Curve Shape Parameter

We model a negative exponential relationship between clean energy surplus and premium in the CESM, assuming clean energy attributes in the WECC would have similar price-quantity dynamics as renewable energy certificates (RECs) in other markets. Historical solar REC (sREC) auction outcomes from PJM states with liquid markets show an exponential relationship between trade volumes and clearing prices (Figure 7).[3] This relationship indicates that as the supply shrinks, buyers are willing to pay increasing premiums to secure clean attributes in the market. On the other hand, if there is ample supply, premiums settle at a relatively low baseline value. The negative exponential shape used in the CESM is a normalized version of the PJM sREC auction outcome graph shapes, tuned using outputs from the AURORA model.

[3] We relied on PJM sREC auction outcomes for the CESM due to a lack of available clean attribute market data in the WECC.

FIGURE 7. PJM SOLAR REC AUCTION PRICE-QUANTITY RELATIONSHIP BETWEEN 2010-2024

CEPC Max Premium Parameter

Based on guidance from PGE, we set the CEPC Max Premium parameter based on the cost of a new build wind resource, assuming that wind would be the source of incremental supply of clean energy beyond what is available from existing resources. We set the CEPC Max Premium to $15/MWh for the year 2030, reflecting a $10/MWh levelized cost of energy (LCOE) for a new wind resource earning the Production Tax Credit and a 1.5× scalar to reflect cost uncertainty not reflected in the LCOE. The LCOE value is based on the 2023 NREL ATB's calculation of the LCOE of a Class 4 onshore wind turbine using the moderate cost trajectory.[4]

CEPC Curve Floor Parameter

We set the Curve Floor parameter based on WECC-wide clean energy surpluses observed in the AURORA results when energy prices are below a certain threshold. Low energy prices indicate high enough clean energy production that there should be no premium associated with its procurement. This study used a $0/MWh threshold price, which indicates clean energy curtailments in the AURORA model. The Curve Floor parameter was set at the minimum WECC-wide surplus observed across all hours when the WECC-wide load-weighted average energy price was at or below the $0/MWh threshold.

2. Calculate WECC-Wide Hourly Clean Energy Premiums

We use the CESM process detailed in Steps 1 through 5 detailed in Section 0 above to calculate the total available WECC-wide surpluses in each hour. Since the premium does not depend on

[4] National Renewable Energy Laboratory. *2023 Annual Technology Baseline*. 2023. https://atb.nrel.gov/electricity/2023/land-based_wind.

how much of the available surplus is deliverable to PGE, we use the CEPC to calculate hourly WECC-wide premiums using the results of Step 5.

3. Implement PGE-Specific Premium Adjustments

We divide each hour's WECC-wide premium by the capacity factor of a reference wind profile in that hour to capture the impact of wind availability on the cost of producing a MWh of clean energy in each hour. A key concern for PGE's CEP is whether to rely on market purchases or to procure new clean generation capacity. An owned or contracted resource seldom produces clean energy equal to its nameplate capacity. Thus, PGE may need more than a MW of clean generation nameplate capacity to produce a MWh of clean energy when needed. Dividing the hourly WECC-wide premium by the capacity factor of a reference wind output profile in that hour serves to make comparable the cost of procuring capacity or purchasing surplus on the market.

IV. Clean Energy Accounting Results

We evaluated potential clean energy surplus availability for the year 2030 based on AURORA model results from the 2023H2 and 2024H2 production cost model databases from Wood Mackenzie. The annual regional and WECC wide generation mix and load modeled in each set of AURORA inputs is given below in Figure 8, followed by the monthly WECC-wide generation mix and load in Figure 9. Both model databases show the WECC-wide and regional generation mixes as having high proportions of clean energy and an annual surplus. WECC-wide surpluses tend to concentrate in the spring months, when loads are low and clean energy generation is high. The Northwest region has higher surplus than the Southwest region, despite higher policy requirements, due to substantial wind and hydro penetration.

FIGURE 8. ANNUAL GENERATION ASSUMPTIONS IN THE AURORA MODEL

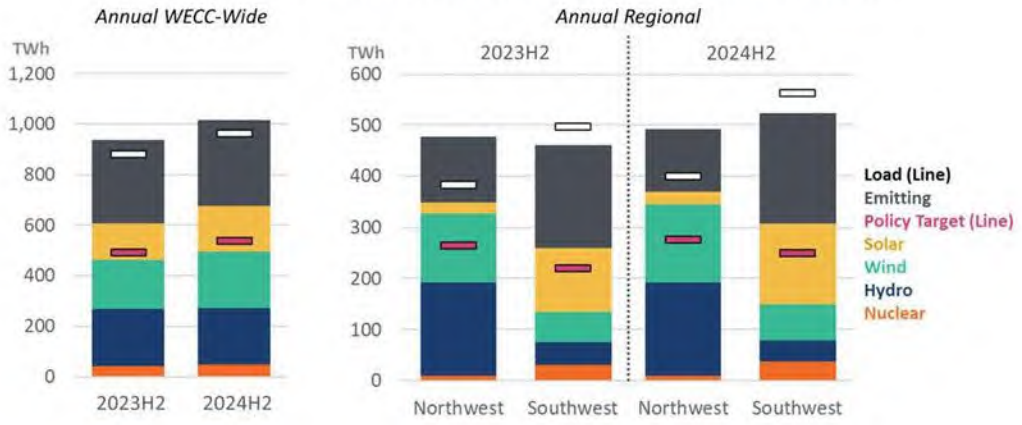
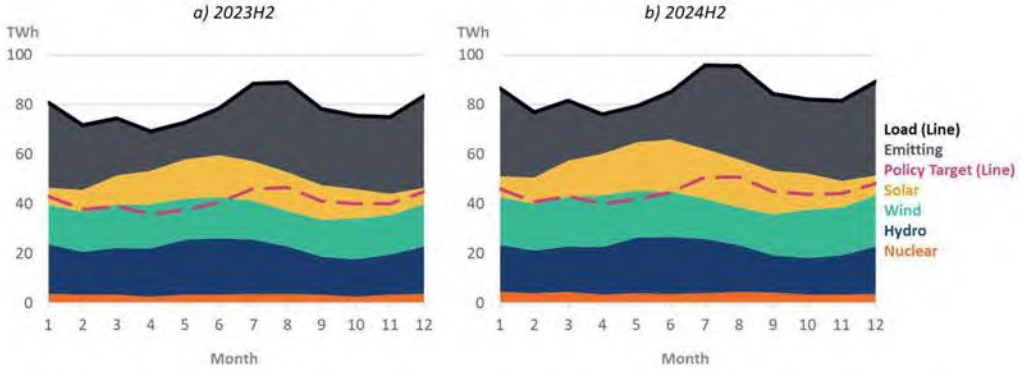
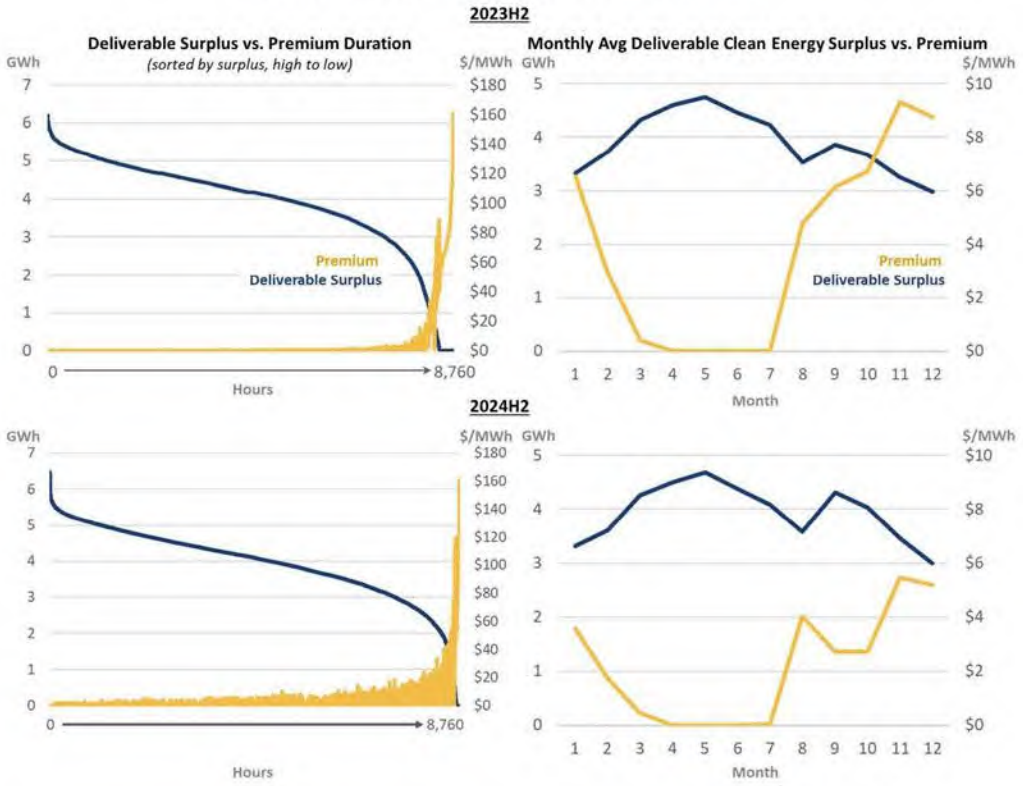


FIGURE 9. MONTHLY GENERATION ASSUMPTIONS IN THE AURORA MODEL



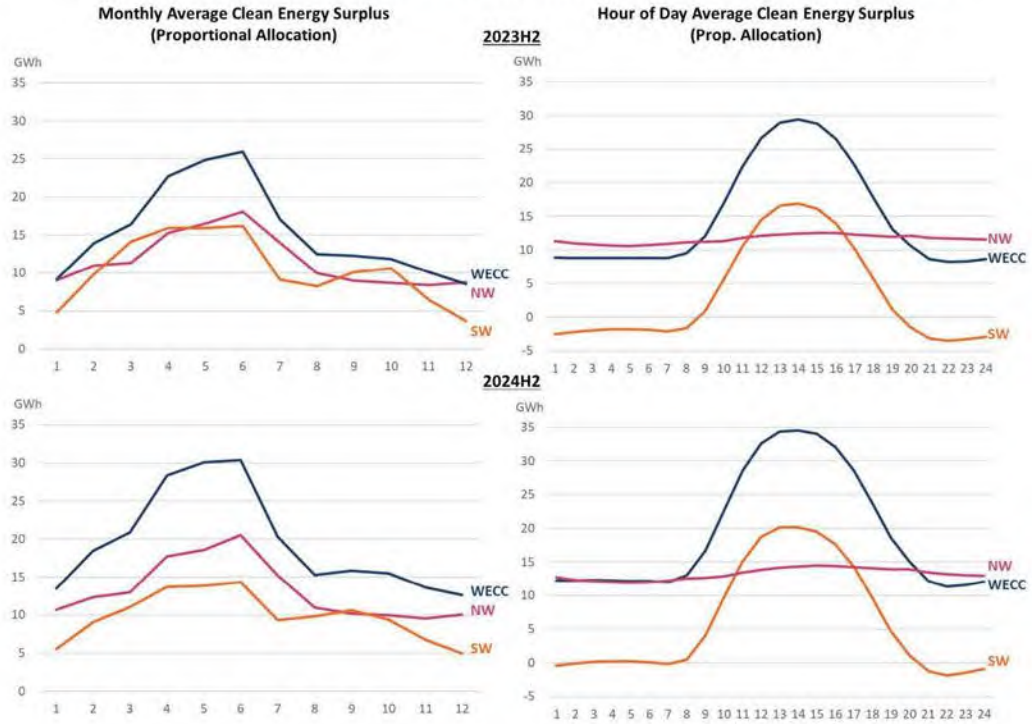
We find that deliverable surpluses are highest in the spring and early summer, roughly in line with the seasonality of clean generation. Premiums follow an inverse pattern and are highest in the winter, when surpluses are low, reflecting the price-quantity relationships defined in the CEPC. Figure 10 below plots the deliverable surpluses and premiums for both sets of AURORA data as a duration curve (left charts) and as average monthly values (right charts). The duration curves plot hourly surplus (blue line) and premium (yellow line) results arranged by surplus quantity in descending order. The monthly charts represent the simple average surplus and premium value for each month.

FIGURE 10. DELIVERABLE SURPLUS AND PREMIUM



We observe substantial variability in WECC-wide and regional surpluses across different months and hours of the day (Figure 11). The Northwest region's monthly clean energy generation patterns drive WECC-wide monthly clean energy surpluses because the Northwest region has a rich wind and hydro resource. On a daily scale, the Southwest region drives WECC-wide surplus patterns due to its large solar resource. In the right charts in Figure 11, the blue line (WECC-wide surplus) has a very similar shape to the orange line (Southwest average surplus), displaying a hump during solar generation hours. The pink line (Northwest average surplus) remains mostly flat across all hours of the day.

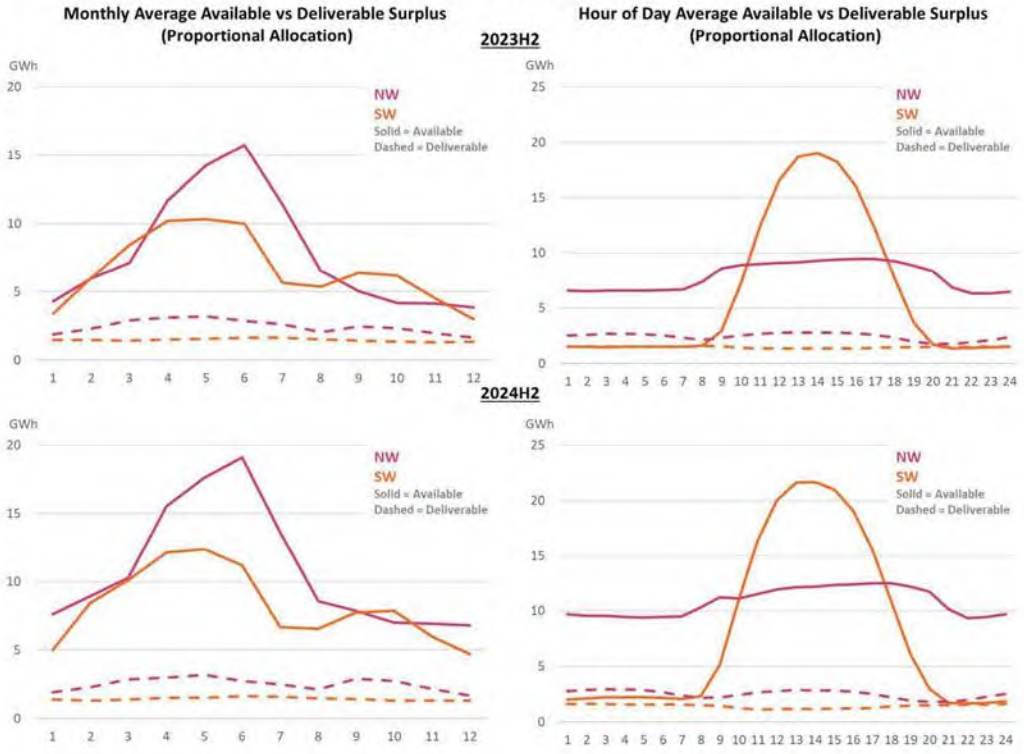
FIGURE 11. WECC-WIDE AND REGIONAL SURPLUSES[5] BY MONTH AND HOUR OF THE DAY



We found that deliverability constraints substantially curtail PGE's access to clean surplus. Figure 12 plots the available (solid line) and deliverable (dashed line) surplus for each region by month (left charts) and hour of day (right charts). PGE's deliverability constraints are most impactful during the springtime for Northwest surpluses and during the daytime for Southwest surpluses, with an overall impact of allowing just over 30% of available surplus to be delivered to PGE.

[5] Charts show average surplus quantities for hours when surpluses are available, before accounting for RMRG deliverability constraints and transfers between NW and SW regions. Aggregating to the WECC-wide level alters the timing and amounts of surpluses shown such that the NW and SW values may add to more than the WECC quantity.

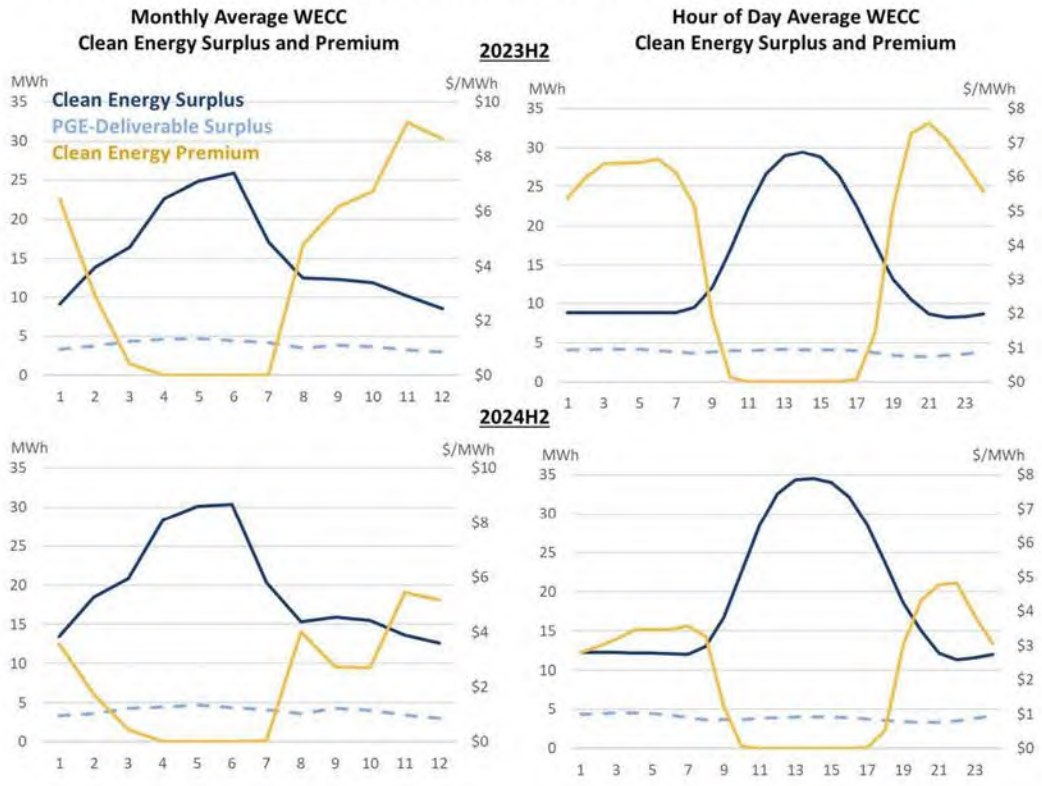
FIGURE 12. REGIONAL SURPLUS DELIVERABILITY RESULTS[6]



Hourly premium results are driven by WECC-wide surplus dynamics, reflecting the inverse relationship between surplus quantity and premium defined in the CEPC (Figure 13). Premium are based on WECC-wide surpluses and do not depend on deliverability to PGE. High WECC-wide surpluses in the spring and during the middle of the day drive down premiums during those periods.

[6] Regional surpluses reflected in Figure 12 reflect surpluses deliverable from the respective regions. The solid lines indicate available surpluses after accounting for transfers from RMRG and between the NW and SW regions. The dotted lines indicate the regional surpluses deliverable to PGE.

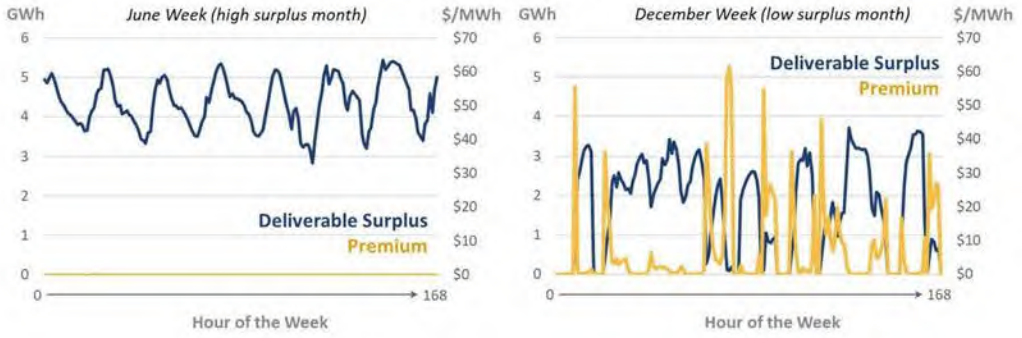
FIGURE 13. WECC-WIDE AVAILABLE AND DELIVERABLE CLEAN ENERGY SURPLUS AND PREMIUM



We examined hourly CESM results to validate the annual, monthly, and hour-of-day trends observed above. Figure 14 plots hourly results for a week in June (left chart) and December (right chart) from the 2023H2 set of results. In June, when surpluses are high, there is no premium. In the December week, surpluses vary throughout the day, often falling to zero during evening hours with peak demand.

FIGURE 14. HOURLY CESM RESULTS

Hourly PGE-Deliverable Clean Energy Surplus and associated Premium



V. Framework Evaluation and Next Steps

The CESM provides a starting point for assessing the availability and cost of clean energy surplus in the WECC and deliverable to PGE.

The strengths of this hourly surplus accounting framework include:

- Broad capture of the fundamental dynamics that drive the availability and relative value of clean energy
- Simplicity in implementation with tunable parameters
- Internal consistency with the AURORA simulations that inform other areas of the PGE IRP analyses.
- Adaptability for studying multiple future outlook scenarios.

There are several areas in which the CESM can be improved:

- Add detail when applying deliverability constraints. The CESM currently includes deliverability constraints at the seams of the OR-WE AURORA zone containing PGE, assuming no transmission limitations in delivering surpluses to the seams from more distant entities. A future refinement could add constraints for calculating clean energy deliverability

to PGE's immediate neighbors and additionally to those neighbors' neighbors. We expect this improvement would reduce surplus deliverable to PGE.

- Refine the hourly surplus/deficit allocation approach. WECC entities may have various clean energy market participation strategies, including front-loading surplus procurements, concentrating purchases during times of abundant production, or attempting to maximize premium revenues. Alternate hourly allocation approaches can capture such behaviors, thereby altering the amount of surplus available to PGE. Adjustments to the allocation approach could increase or decrease the surplus available to PGE, depending on the specifics of the approach.
- Consideration of moving surplus within days or across days with storage. Our initial approach uses storage dispatch profiles as they are in Aurora results, but the WECC entities may dispatch storage resources to alter the amount of surplus available. We expect this improvement could modestly increase the surplus deliverable to PGE because the AURORA model already optimizes storage dispatch.
- Refine the approach to calculating state targets to account for varying clean energy eligibility requirements. We expect this refinement would have little to no impact on surplus deliverable to PGE because ineligible non-emitting energy can be traded to satisfy other states' requirements.
- Include the impacts of renewable forecast uncertainty. Deviations between day-ahead forecasts and real-time clean energy production would alter the quantity of available surplus and the utilization of transmission paths. We expect this refinement would have modest impacts on deliverable surplus quantities because renewable forecast errors are small compared to base production schedules and forecasting methods continue to improve.

Appendix A: Detailed List of Assumptions

General assumptions

- Each AURORA zone falls within a single state
  - Zones that are not labeled as belonging to specific states will be mapped based on proximity

- Clean energy surplus reflects availability after accounting for clean energy commitments to other states' policy goals
- Clean energy generated outside of PGE is only committed to state-legislated targets, not corporate or voluntary goals (i.e., those goals compete with PGE for clean energy surplus)
- Curtailed clean energy is assumed to be undeliverable and thus not considered part of the WECC-wide surplus
- Same set of resource types considered "clean" for all state RPS programs
- Transmission and deliverability constraints limit WECC-wide clean energy surplus only on a regional basis, if at all

Surplus estimation assumptions

- All clean energy policy targets increase linearly by year from 2024 until their mandated achievement year, with trajectories including interim targets
- All clean energy in excess of a balancing area's (BA's) load is counted as surplus
- If this results in an annual deficit relative to policy targets for the BA, then we assume that WECC-wide surpluses in other hours are reduced proportionally to return the BA to annual compliance
- Clean energy in states without policy targets is all counted as surplus
- There are no contributions to meeting annual policy targets from banked clean energy credits
- Surplus deliverability is not meaningfully impacted by sub-zonal transmission constraints
- Sufficient TTC exists between sub-zones of NW and SW deliverability regions to balance surpluses/deficits
- No shifting of surpluses between hours within a day (e.g., by using storage)

Premium estimation assumptions

- Premium price quantity dynamic resembles that of REC markets
- Maximum premium is representative levelized net cost of new wind build for PGE with hourly adjustments for wind availability
- Minimum premium is zero

- Surplus floor will be related to AURORA surplus quantities and energy prices
- Premium curve is static across the year

Appendix B: Table of Input Data Sources

CESM Input	Source
Generator state mappings	AURORA input
Generator type mapping	AURORA input
State RPS/CES targets	Brattle assumption based on public data from LBNL
Mapping of AURORA zones to states	Brattle team assumption
RPS unit type eligibility by program	Brattle team assumption
Transmission capacity from WECC zones to PGE/trading hubs	AURORA input
Hourly flow on transmission paths	AURORA results
Zonal hourly load	AURORA results
Hourly generation by unit	AURORA results
Zonal generator-weighted LMP	AURORA results
Annual market purchase premium floor and ceiling	Brattle assumption
Clean energy premium curve shape	Brattle assumption based on PJM REC auction outcomes

Appendix C: AURORA Modeled Zonal Topology And Resource Types

Figure 15 contains the zonal and transmission topology modeled in the AURORA database.

FIGURE 15. AURORA MODELED ZONAL TOPOLOGY AND TRANSMISSION CONNECTIONS

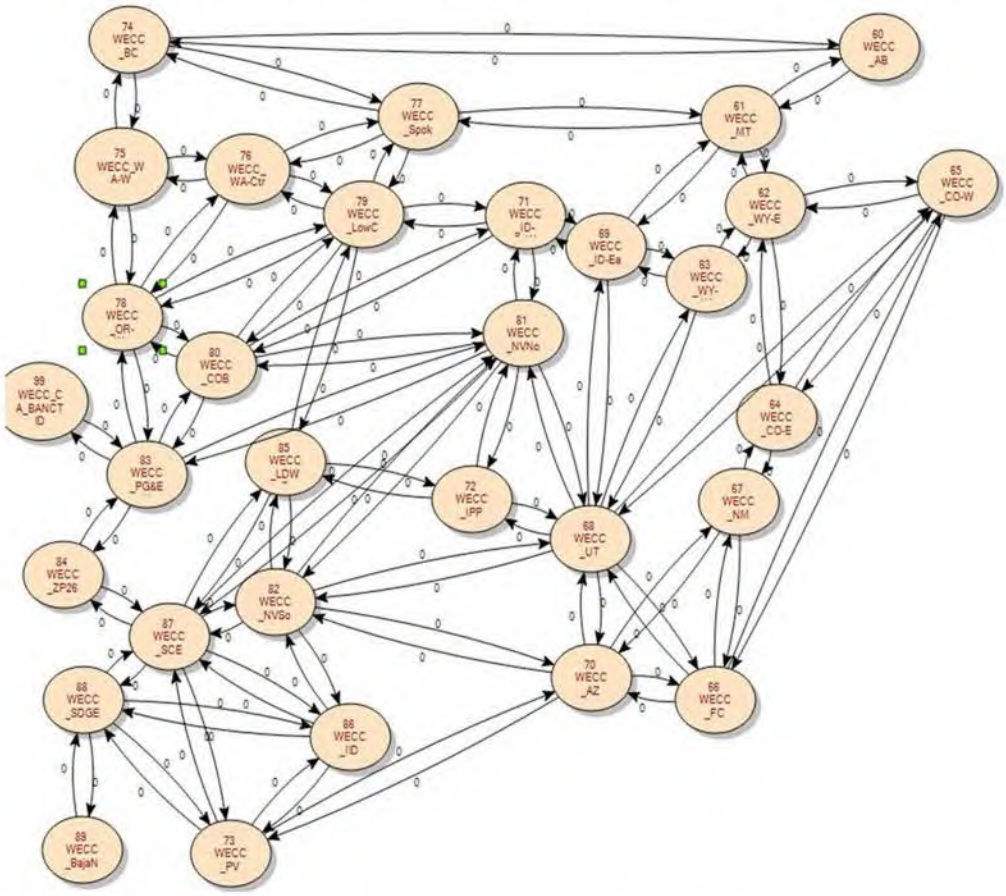


Table 1 contains a mapping of zones modeled in AURORA to WECC states.

TABLE 1. MAPPING OF AURORA ZONES TO STATES

AURORA Zone	State
WECC_Alberta	Alberta
WECC_Montana	Montana
WECC_Wyoming-RMPA	Wyoming
WECC_Wyoming-NWPP	Wyoming
WECC_Colorado East	Colorado
WECC_Colorado West	Colorado
WECC_FourCorners	New Mexico
WECC_NewMexico	New Mexico
WECC_Utah	Utah
WECC_PNW_IdahoEast	Idaho
WECC_Arizona	Arizona
WECC_PNW_IdahoSouthwest	Idaho
WECC_IPP	California
WECC_Palo Verde	California
WECC_BritishColumbia	British Columbia
WECC_PNW_WashingtonWest	Washington
WECC_PNW_WashingtonCentral	Washington
WECC_PNW_Spokane	Washington
WECC_PNW_OregonWest	Oregon
WECC_PNW_LowerColumbia	Washington
WECC_COB	COB Trading Hub
WECC_NevadaNorth	Nevada
WECC_NevadaSouth	Nevada
WECC_CA_PGandE_North	California
WECC_CA_PGandE_ZP26	California
WECC_CA_LADWP	California
WECC_CA_IID	California
WECC_CA_SCE	California
WECC_CA_SDGE	California
WECC_BajaNorth	Mexico
WECC_CA_BANCTID	California

Table 2 contains a list of resource types modeled in AURORA (both 2023H2 and 2024H2 datasets) and their designations as clean or other in the CESM.

TABLE 2. CESM AURORA RESOURCE TYPE MAPPING

AURORA Unit Type	CESM Designation
Hydro	clean
Nuclear	clean
Solar Utility	clean
Solar Utility Non-PTC	clean
Solar Utility PTC	clean
Wind Offshore	clean
Wind Onshore	clean
Wind Onshore Non-PTC	clean
Wind Onshore PTC	clean
Demand Response	load
Electric Vehicles	load
Solar Distributed	load
Battery Storage 12 Hour	other
Battery Storage 4 Hour	other
Battery Storage 8 Hour	other
Coal	other
Energy Storage	other
Gas CC	other
Gas Cogen	other
Gas Peaking	other
Gas Steam	other
Oil	other
Other	other

Appendix G Stakeholder engagement

June 4, 2025 CEP/IRP Roundtable 25-4

- Agenda (video, ppt)
- Examining Winter Reliability Constraints (video, ppt)
- Updated Price Forecast (video, ppt)
- Final Portfolio (video, ppt)
- Additional Tax Policy and Reliability Planning Scenarios (video, ppt)
- Report Structure (video, ppt)
- Closing Remarks | Next Steps (video, ppt)

April 25, 2025 CEP/IRP Roundtable 25-3

- Agenda (video, ppt)
- Draft Portfolio Analysis Results (video, ppt)
- Closing Remarks | Next Steps (video, ppt)

February 19, 2025 CEP/IRP Roundtable 25-2

- Agenda (video, ppt)
- Integrating Clean Energy Availability (video, ppt)
- Portfolio Design II (video, ppt)
- Market Scenarios (video, ppt)
- Large Industrial Customer Growth Details (video, ppt)
- WRAP Based Needs (video, ppt)
- Closing Remarks | Next Steps (video, ppt)
- Stakeholder Feedback and PGE Responses

January 8, 2025 CEP/IRP Roundtable 25-1

- Agenda (video, ppt)
- Update Filing Date (video, ppt)
- 75 percent Transmission Requirements (video, ppt)
- Resource Effective Load Carrying Capabilities (video, ppt)
- Energy Values (video, ppt)
- Transmission Options | Energy Strategies (video, ppt)
- Closing Remarks | Next Steps (video, ppt)

December 16, 2024 Stakeholder Engagement

- Long Lead-Time Resource RFI (ppt)

November 6, 2024 CEP/IRP Roundtable 24-7

- Agenda (video, ppt)
- CEP/IRP Update Filing Extension (video, ppt)
- Calpine (video, ppt)
- Updated Energy/Capacity Positions (video, ppt)
- Updated Emissions Projection (video, ppt)
- Transmission - Step 3 – Market Access (video, ppt)
- Portfolio Design (video, ppt)
- Closing Remarks | Next Steps (video, ppt)
- Stakeholder Feedback and PGE Responses

October 2, 2024 CEP/IRP Roundtable 24-6

- Agenda (video, ppt)
- RFP Proxy (video, ppt)
- DER Update (video, ppt)
- Transmission | Step 1: Existing Capacity (video, ppt)
- Transmission | Step 2: Future Capacity (video, ppt)
- Updated Price Forecast (video, ppt)
- Closing Remarks | Next Steps (video, ppt)
- Stakeholder Feedback and PGE Responses

September 4, 2024 CEP/IRP Roundtable 24-5

- Agenda (video, ppt)
- Transmission Options (video, ppt)
- ETO: Updated Energy Efficiency Forecast (video, ppt)
- Cadeo: CBI Study (video, ppt)
- Closing Remarks | Next Steps (video, ppt)
- Stakeholder Feedback and PGE Responses

August 7, 2024 IRP Roundtable 24-4

- Agenda (video, ppt)
- Brattle Study: Clean Energy Availability (video, ppt)
- Capacity Need (video, ppt)
- Closing Remarks | Next Steps (video, ppt)

July 11, 2024 IRP Roundtable 24-3

- Agenda (video, ppt)
- Transmission Options (video, ppt)
- Load Forecast (video, ppt)
- Resource Economics Update (video, ppt)
- Small Scale Renewables (video, ppt)
- ROSE-E Changes (video, ppt)
- Closing Remarks | Next Steps (video, ppt)

June 5, 2024 IRP Roundtable 24-2

- Agenda (video, ppt)
- North Plains Connector (video, ppt)
- Hourly Energy & Emissions Accounting
    - Discussion Framework | Part I (video, ppt)
    - Capacity Expansion | Part II (video, ppt)
- Qualifying Facility Forecast (video, ppt)
- Closing Remarks | Next Steps (video, ppt)

May 1, 2024 IRP Roundtable 24-1

- Agenda (video, ppt)
- 2024 Schedule | Feedback Form (video, ppt)
- CEP/IRP Update | Updates & Non-Updates (video, ppt)
- Community benefits indicators (CBI) Study (video, ppt)
- Transmission Study (video, ppt)
- Closing Remarks | Next Steps (video, ppt)

Appendix H Transmission planning and interconnection process

H.1FERC Order 1000 process

PGE coordinates its planning processes with other transmission providers through membership in NorthernGrid and the Western Electric Coordinating Council (WECC). PGE uses the NorthernGrid process for regional planning, coordination with adjacent regional groups and other planning entities for interregional planning, and development of proposals to WECC. Additional information is included in PGE's OATT Attachment K, in Transmission Planning Business Practice on OASIS, and on NorthernGrid's website at https://www.northerngrid.net.

H.2 FERC Order 1920 process

FERC Order No. 1920 reforms the regional transmission planning process by establishing a new 20-year, scenario-based Long-Term Regional Transmission Planning (LTRTP) process.[167] Three diverse and plausible scenarios must be studied, and these scenarios must be re-assessed and revised at least once every five years. Sensitivity analysis of uncertain operational outcomes during multiple concurrent and sustained generation and/or transmission outages due to an extreme weather event across a wide area must also be performed for each scenario. PGE's compliance with FERC Order No. 1920 will be primarily realized through modifications to the existing NorthernGrid regional transmission planning process to incorporate the new requirements established in FERC Order No. 1920.

The new long-term scenarios must be developed using a set of seven categories of factors. These categories of factors are like those used in integrated resource planning, including criteria such as federal, state, and tribal rules and regulations for resource mix, decarbonization, and electrification. Factor Category 3 specifically requires incorporating integrated resource plans into the scenario development. The requirement for these using these factor categories in scenario-based transmission planning closely aligns the long-term regional transmission planning process with the integrated resource planning process.

FERC Order No. 1920 also requires that transmission providers measure a set of seven benefits for each scenario to evaluate LTRTP facilities over a 20-year horizon starting from the in-service date of the facility. The seven benefits go beyond traditional reliability metrics in the existing transmission planning processes to address economic benefits for transmission projects that integrate cost-effective new resources, such as lowering production costs and mitigating congestion. This again speaks to the alignment with the requirements of FERC Order No. 1920 and the integrated resource planning process.

[167] FERC Order No. 1920, issued on May 13, 2024.

Additional requirements of FERC Order No. 1920 include development of selection criteria for facilities, re-evaluation of facilities due to changing policies or reliability criteria, use of grid-enhancing technologies, cost allocation, and more transparency into the local transmission planning, regional transmission planning, and interregional transmission planning processes.

PGE appreciates the strong partnership with the relevant state entities throughout the Order No. 1920 six-month state engagement period, which began November 1, 2024, and concludes November 1, 2025. The NorthernGrid transmission providers also commenced an open stakeholder engagement process to receive feedback on the new LTRTP in March 2025 per the new requirement issued in FERC Order No. 1920-A.[168] NorthernGrid will propose on compliance the start of the long-term regional transmission planning process, which will commence no later than two years after the filing date. The states in the NorthernGrid and WestConnect regional planning organizations requested and received a compliance extension at FERC to allow for more time for cost allocation discussions. All NorthernGrid FERC-jurisdictional transmission providers must complete their compliance filing by December 12, 2025. A second compliance filing for the new interregional transmission planning requirements is due February 12, 2026.

H.3 Local transmission planning process

H.3.1 Process overview

PGE's OATT is posted on its Open Access Same-time Information System (OASIS) at http://oasis.oati.com/PGE. Additional information regarding Transmission Planning is located in the Transmission Planning folder on PGE's OASIS.

The Local Transmission Plan (LTP) is prepared within the two-year process as defined in PGE's OATT Attachment K and summarized in **Table 39**. The LTP identifies the Transmission System facility additions required to reliably interconnect and transmit forecasted generation resources and serve the forecasted Network Customers' load, Native Load Customers' load, and Point-to-Point Transmission Customers' requirements, and also includes legacy, non-OATT agreements and rollover rights over a ten-year planning horizon. Additionally, the LTP typically incorporates the results of any stakeholder-requested economic congestion studies results that were performed.

Table 39. Local Transmission Planning Cadence

		Quarter	Tasks
Near Term	Even Years	1	Select Near Term base cases and gather load data
		2	Post Study Methodology on OASIS, select one Economic Study for evaluation
		3 & 4	Select Longer Term base cases, post draft Near Term Plan on OASIS, hold public meeting to solicit stakeholder comment

[168] FERC Order No. 1920-A, issued on November 21, 2024.

		Quarter	Tasks
		4	Incorporate stakeholder comments and post final Near Term plan on OASIS
Longer Term	Odd Years	5	Gather load data and accept Economic Study requests
		6	Select one Economic Study for evaluation
		7 & 8	Post draft Longer Term plan on OASIS, hold public meeting to solicit stakeholder comment
		8	Post final Longer Term plan on OASIS, submit final Longer Term Plan to stakeholders and owners of neighboring systems

PGE updates its Transmission Customers about activities and progress made under the Attachment K planning process during regularly scheduled customer meetings. Meeting announcements, agendas, and notes are posted in the Customer Meetings folder on PGE's OASIS. Meeting dates are posted on PGE's OASIS.

H.3.2 NERC planning standards (TPL-001)

PGE's Transmission System is designed to reliably supply projected customer demand and projected Firm Transmission Service. Studies are performed annually to evaluate where Transmission upgrades may be needed to meet the performance requirements established in the NERC TPL-001-5 Reliability Standard and the WECC TPL-001-WECC-CRT-3.2 Regional Criteria. Results from the annual TPL-001 process are made available via the Local Transmission Plan document, which is posted publicly on PGE's OASIS page.

The summer (June 1st through October 31st) and winter (November 1st through March 31st) load seasons are considered the most critical study seasons due to heavier peak loads and high power transfers over PGE's Transmission and Distribution System to its customers. However, the off-peak seasons have different regional flow patterns that can result in issues not seen during peak load times. PGE defines the seasons to align with Attachment I of the RC West.[169]

PGE maintains system models within its planning area for performing the studies required to complete the system assessment. These models use data that is provided in WECC base cases in accordance with the MOD-032 reliability standard. Electrical facilities modeled in the cases have established ratings, as defined in PGE's "Facility Ratings Methodology" document and in accordance with the FAC-014 reliability standard. A facility rating is determined based on the most limiting component in each transmission facility, in accordance with the FAC-008 reliability standard.

[169] RC West Southwest Power Pool BC Hydro, "RC Guidelines for Seasonal Assessment and Coordination Process," Attachment I, page 14, https://www.caiso.com/documents/rc0680.pdf.

Reactive power resources are modeled as made available in the WECC base cases. For PGE, reactive power resources include shunt capacitor banks available on the 230 kV, 115 kV, and 57 kV systems.

Studies are evaluated for the Near-Term Planning Horizon (years 1 through 5) and the Long-Term Planning Horizon (years 6 through 10) to ensure adequate capacity is available on PGE's transmission system. The load modeled in the studies is obtained from PGE's corporate forecast, reflecting a 1-in-20 demand level for peak summer and peak winter conditions. Known outages of generation or transmission facilities with durations of at least six months are appropriately represented in the system models. However, any significant outage is studied as a result of an N-1-1 contingency and is therefore analyzed for every major season and year that PGE studies as part of the TPL process. Transmission equipment is assumed to be out of service in the base case system models if there is no spare equipment or mitigation strategy for the loss of the equipment.

Studies in the Near Term – Two Year Planning Horizon and the Near Term – Five Year Planning Horizon are performed for peak summer, peak winter, and off-peak spring conditions. Sensitivity studies are performed for each of these cases by varying the study parameters to stress the system within a range of credible conditions that demonstrate a measurable change in performance. PGE adjusts the real and reactive forecasted load and the transfers on the paths into the Portland area on all sensitivity studies. For peak system sensitivity cases, the 1-in-20 load forecast.

The load levels used in the 2024 Local Transmission Plan are available on PGE's OASIS page.

The Bulk Electric System (BES) is evaluated for steady state and transient stability performance for planning events described in Table 1 of the NERC TPL-001-5.1 reliability standard. When system simulations indicate an inability of the systems to respond as prescribed in the NERC TPL-001-5.1 standard, PGE identifies projects and/or Corrective Action Plans which are needed to achieve the required system performance throughout the Planning Horizon.

H.3.2.1 Steady state studies

PGE performs steady-state studies for the Near-Term and Long-Term Transmission Planning Horizons. The studies consider all Contingency scenarios identified in Table 1 of the NERC TPL-001-5.1 reliability standard (Categories P0-P7) to determine if the BES meets performance requirements. PGE uses the criteria defined in the WECC TPL-001-WECC-CRT-3.2 document to establish acceptable System steady state voltage limits and post-Contingency voltage deviations. The WECC System Performance Criteria requires that the change in bus voltage percentage not exceed 8 percent for N-1 contingencies. Additionally, internal PGE performance criteria require that the change in bus voltage percentage not exceed 10 percent for N-2 and N-1-1 contingencies. These studies also assess the impact of Extreme Events on the System expected to produce severe System impacts.

The Contingency Analyses simulate the removal of all Elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without Operator intervention. The analyses include the impact of the subsequent tripping of generators due to

voltage limitations and tripping of Transmission Elements where relay loadability limits are exceeded. Automatic controls simulated include phase-shifting transformers, load tap changing transformers, and switched capacitors and reactors.

Cascading, or the uncontrolled successive loss of System Elements triggered by a Disturbance that results in the inability of the Elements of the BES to regain a state of operating equilibrium is defined as a System instability. Cascading is not allowed to occur for any Contingency analysis. If the analysis of an Extreme Event concludes there is Cascading, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) is completed.

H.3.2.2Voltage stability studies

PGE's Transmission System is evaluated for voltage stability in accordance with the WECC established criteria.[170] These performance criteria are summarized in the table below. Any voltage stability result that violates the criteria listed below is defined as a System instability. Contingencies to PGE and adjacent utility equipment at 500 kV and 230 kV are evaluated. All planning events were screened or reviewed for voltage stability requirement per WECC Criterion WR5 by simulating P0 and P1 events at 105 percent of forecasted peak load and simulating P2-P7 events at 102.5 percent of forecasted peak load. This screening indicated all planning events met the reactive margin requirement with the implementation of their associated operating procedures, RAS, or Corrective Action Plans.

H.3.2.3Transient stability studies

PGE evaluates the transient stability performance of the BES for select Contingencies to PGE and adjacent utility equipment at 500 kV, 230 kV, and 115 kV. The studies evaluate single line-to-ground and three-phase faults to these facilities, including generators, bus sections, breaker failure, and loss of a double-circuit Transmission line. Extreme events are studied for three-phase faults with Delayed Fault Clearing.

For all 500 kV and 230 kV breaker positions, PGE implements high-speed protection through two independent relay systems utilizing separate current transformers for each set of relays. For a fault directly affecting these facilities, normal clearing is achieved when the Protection System operates as designed and faults are cleared within four to six cycles.

PGE implements breaker-failure protection schemes for its 500 kV and 230 kV facilities, and the majority of 115 kV facilities. Delayed clearing occurs when a breaker fails to operate, and the breaker-failure scheme clears the fault. Facilities without delayed clearing are modeled as such in the Contingency definition.

The transient stability results are evaluated for compliance with the following NERC and WECC System performance requirements. The simulation durations are run to 20 seconds. All

[170] "Guide to WECC/NERC Planning Standards I.D: Voltage Support and Reactive Power," prepared by the Reactive Reserve Working Group (RRWG) and approved by the Technical Studies Subcommittee (TSS) on March 30, 2006. https://www.wecc.biz/_layouts/15/WopiFrame.aspx?sourcedoc=/Reliability/Voltage%20Stability%20Guide.pdf&action=default&DefaultItemOpen=1

oscillations that do not show positive damping within 20 seconds after the start of the studied event shall be deemed unstable.

H.3.2.4Short circuit studies

Short circuit studies are performed annually addressing the Near-Term Planning Horizon. If the short circuit current interrupting duty on a circuit breaker exceeds 97 percent of its equipment rating, PGE identifies projects and/or Corrective Action Plans which are needed to achieve the required System performance throughout the Near- and Long-Term Planning Horizon.

H.4 Other relevant transmission planning standards

H.4.1 TPL-007

Transmission system planning requirements surrounding geomagnetic disturbances are addressed in NERC Standard TPL-007-4. Geomagnetic disturbances occur when high-energy emissions from the sun, known as coronal mass ejections, interact with the Earth's magnetic field. The resulting electromagnetic disturbances can propagate along long conductors, such as transmission lines, and have been known to cause power system damage in the past.[171]

TPL-007-4 requires that PGE:

- Maintain and report information on all Bulk Electric System transformers in its service territory
- Install a geomagnetic current sensor on at least one bulk transformer it its service territory
- Coordinate on a geomagnetic disturbance study with regional stakeholders every five years
- Address any thermal or reactive power exceedances identified in this study via a Corrective Action Plan.

Historically, PGE has not experienced significant system impacts from geomagnetic disturbances. This is due to a combination of the transmission topology in the area and the nature of the soil in the Willamette Valley. During a recent geomagnetic storm in May 2024, which was the highest recorded in nearly 20 years, there were negligible effects detected on PGE's system.

The related NERC Standard EOP-010-1 governs how PGE works with NASA and the Reliability Coordinator (RC West) to address geomagnetic disturbances in the operations horizon.

H.4.2 TPL-008 (in development)

On June 15, 2023, FERC issued FERC Order No. 896 that acknowledges the "challenges associated with planning for extreme heat and cold weather events, particularly those that occur during periods when the Bulk-Power System must meet unexpectedly high demand. Extreme heat and cold weather events, which can cause public safety and economic risks, have occurred

[171] See for example, Guillon, et.al., "A Colorful Blackout: The Havoc Caused by Auroral Electrojet Generated Magnetic Field Variations in 1989" IEEE, Nov 2016. https://ieeexplore.ieee.org/document/7592967.

with greater frequency in recent years and are projected to occur with even greater frequency in the future. As such, the impact of concurrent failures of Bulk-Power System generation and transmission equipment and the potential for cascading outages that may be caused by extreme heat and cold weather events should be studied and corrective actions should be identified and implemented."[172]

Part of the Order 896 effort involves the creation of a new NERC Standard, TPL-008-1, which currently in the drafting phase (as of August 2024). It is expected to be finalized in early 2025, with the various requirements having implementation dates of 12- to 60-month.

While the standard is not yet finalized, in general, it will require Transmission Planning entities such as PGE to:

- Coordinate on the development of extreme weather base cases for both cold winter and hot summer conditions
- Model and simulate the ability of the transmission system to respond to transmission outage scenarios (i.e. contingencies) during these extreme weather events
- Develop Corrective Action Plans for any scenarios that do not meet the established acceptance criteria in the standard

The goal of this standard is to ensure that the transmission system remains robust to future extreme weather conditions.

H.4.3 FERC Order No. 2023

FERC Order No. 2023 reforms the large generator interconnection process to make it more efficient by moving to a first-ready, first-served cluster study process.[173] The new process consists of a 150-day Cluster Study (or Cluster Restudy) and a 90-day or 180-day Facilities Study. New financial and readiness requirements, including increased deposits, increased site control, and significant withdrawal penalties are aimed to reduce the number of speculative interconnection requests entering the queue and, as a result, minimize the number of withdrawals from the interconnection queue, which typically result in restudies, lengthening the interconnection study process. These improvements provide more certainty that the new resources identified in the integrated resource planning process can be energized when they are needed, minimizing delays in the interconnection study process.

Information available to prospective interconnection customers is improved with the publishing of an interconnection heatmap, which will be updated at the end of every cluster study or cluster restudy. This heat map can be utilized in the integrated resource planning process to identify on-system locations with existing capacity for new renewable resources.

New advancements were added to FERC Order No. 2023 to allow more flexibility and timeliness improvements for interconnecting new resources. First, multiple customers at the same site with the same Point of Interconnection (POI) can submit a single interconnection request. This

[172] N. Am. Elec. Reliability Corp., 183 FERC ¶ 61,191 (2023) (FERC Order), Final Rule.
[173] FERC Order No. 2023, issued on November 6, 2023.

streamlines jointly owned interconnection projects because multiple owners do not need to submit individual requests. Second, Surplus Interconnection Service can be requested for a project with a signed large generator interconnection agreement – the project no longer must be in commercial operation. This allows for more co-location of different renewable resources behind a single POI to move faster, not waiting for the energization of the first resource to be able to apply for the subsequent resource. Finally, FERC Order No. 2023 requires transmission providers to evaluate alternative transmission technologies for each identified network upgrade. These alternative transmission technologies traditionally can be constructed and energized before traditional solutions, often at a lower cost. All these improvements provide even more certainty to the interconnection process timeline for use in the integrated resource planning process.

To continue alignment with state-jurisdictional and FERC-jurisdictional large generator interconnection processes, the QF-LGIP was amended to conform with the cluster study process. This is beneficial for QF projects, as these projects will be subject to the same cost allocation and sharing as the FERC-jurisdictional projects, potentially reducing costs by spreading across more projects. The OPUC approved PGE's filing with an effective date of January 7, 2025.

PGE began the Transitional Cluster Study on January 6, 2025 to study projects in the serial queue as of May 26, 2024, which was 30 days after PGE submitted its compliance filing to FERC. There are no QF-LGIP projects in the Transitional Cluster Study, as none were in the interconnection queue as of May 26, 2024. The first Cluster Study Request Window for when new large generation projects can request interconnection will open January 1, 2026.

H.4.4 Miscellaneous

In addition to the transmission planning specific standards, there are a number of additional NERC standards in which transmission planning is involved. These include:

- Establishing requirements for generation requesting to interconnect to the Bulk Electric System (FAC-001)
- Establishing a study process for generation interconnection (FAC-002)
- Vegetation management practices near transmission lines (FAC-003)
- Development of detailed generator models, including real and reactive power capabilities (MOD-025), exciter models (MOD-026), and governor and turbine models (MOD-027)
- Coordination of transmission base case development (MOD-032) (Note: PGE and neighboring utilities coordinate this process through the Western Power Pool and the Western Electricity Coordinating Council)
- Validation of transmission base cases for both steady-state and transient stability, utilizing recorded historical events (MOD-33)

- Development of Underfrequency Load Shedding (PRC-006) and Undervoltage Load Shedding (PRC-010) schemes to maintain system stability during extreme transient events.

These related study efforts help ensure that the future state of the transmission system is modeled accurately and that planners can make the best long-term decisions regarding necessary upgrades to reliably maintain the grid.

Appendix I Inputs for state RA requirements portfolio

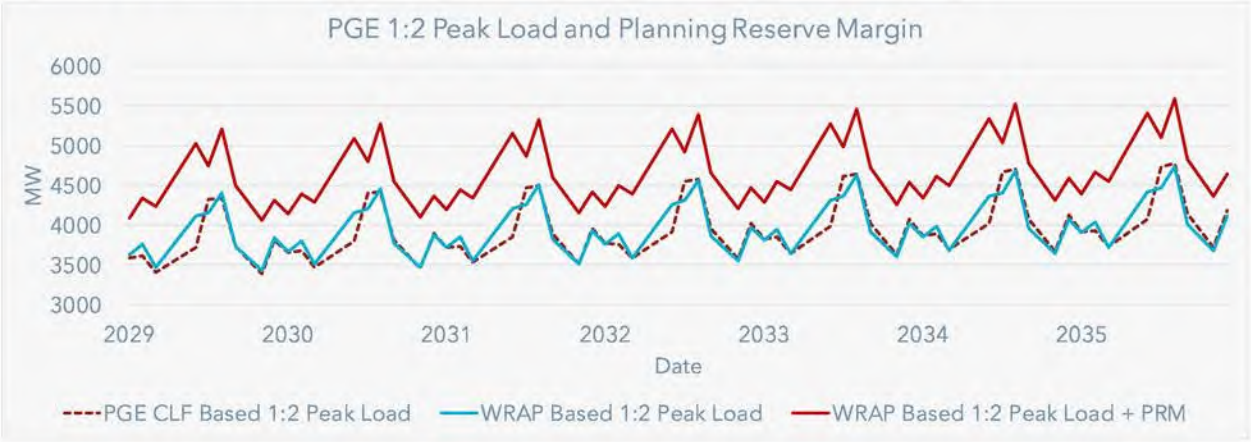
PGE used demand and supply assessment methods from the Western Resource Adequacy Program (WRAP) to analyze the adequacy of PGE's system across the IRP planning horizon. These methods provide the primary metrics needed to derive capacity need and ELCCs for portfolio modeling based on State RA Requirements, which currently rely on WRAP methodology. WRAP metrics for Summer 2026 and Winter 2025-2026 in the MID-C subregion, and WRAP's 2025 qualifying capacity contribution (QCC) estimates for PGE resources are the primary inputs for this exercise.[174,175]

I.1 WRAP based load forecast

PGE estimated load requirements using WRAP methodology for seasonal peak load forecasts plus the WRAP estimated PRM required to achieve a 1 event in 10 years adequacy metric. 5-years of historical PGE load data was used to estimate 1:2 peak load for summer (May-September) and winter (November-March) months as described in WRAP Business Practice Manual (BPM) - 103 – Participant Forward Showing Capacity Requirements.[176] A PGE specific annual growth rate of 1.2 percent was used to scale peak loads across the planning horizon.[177] This growth rate was estimated using PGE's May 2024 load forecast. WRAP's month specific PRM was applied to the resulting load forecast to arrive at estimated load requirement by month.[178] **Figure 94** shows the resulting load forecast for a portion of the planning horizon with and without the PRM. For comparison the median of maximum peak monthly load from the PGE's May 2024 Corporate Load Forecast (CLF) is show. The figure shows there is close alignment in estimated 1:2 peak loads from PGE estimates and WRAP based estimates. There is a divergence in the month of June due to a heavier weighting of the 2021 heat dome event as only 5 years of historical load data are used in the WRAP based estimates.

[174] WRAP Metrics for Summer 2026
[175] WRAP Metrics for Winter 2025-2026
[176] WRAP BPM 103
[177] WRAP's established growth rate is 1.1%, as defined in WRAP BPM-103. 1.1% was defined through and informal survey process, as described in the WRAP's Detailed Design Document – March 2023. Rather than use the establish growth rate for this exercise, PGE elected to estimate a growth rate specific its system.
[178] Preliminary values published 3-31-2024 used for winter season months.

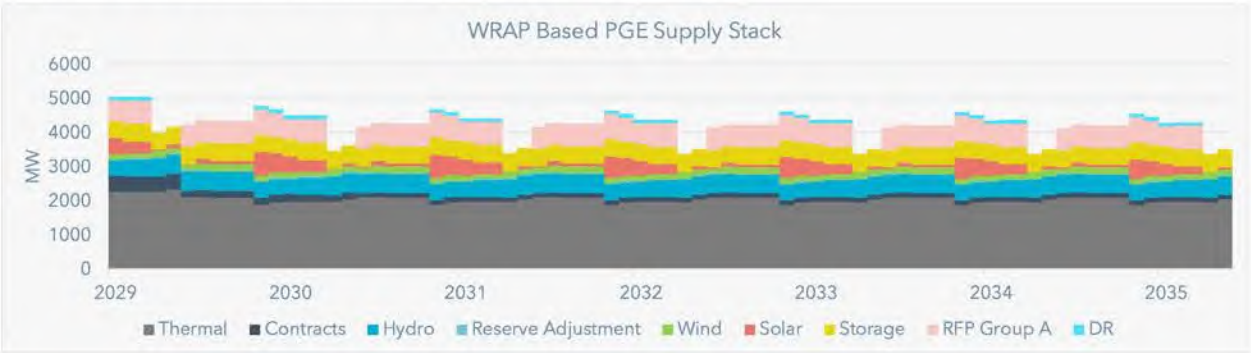
Figure 94. WRAP Based PGE 1:2 Peak Load and Planning Reserve Margin



I.2 WRAP based supply forecast

The company used WRAP provided estimates of resource specific QCC values to estimate the capacity contribution of existing PGE resources in each month of the WRAP summer and winter seasons. WRAP's Winter 25-26 Forward showing (FS) and Summer 2026 FS qualifying capacity values were used capacity assumptions across the planning horizon. Exits and entry from the supply stack were assumed in accordance with assumptions used for resource adequacy modeling in Sequoia. For example, exits were assumed based on known contract expiration dates for the related resources or structured agreements and 2023 RFP Proxy resources were assumed to enter the supply stack in January 2028. **Figure 95** displays the supply assumptions that resulted from this WRAP based forecast.

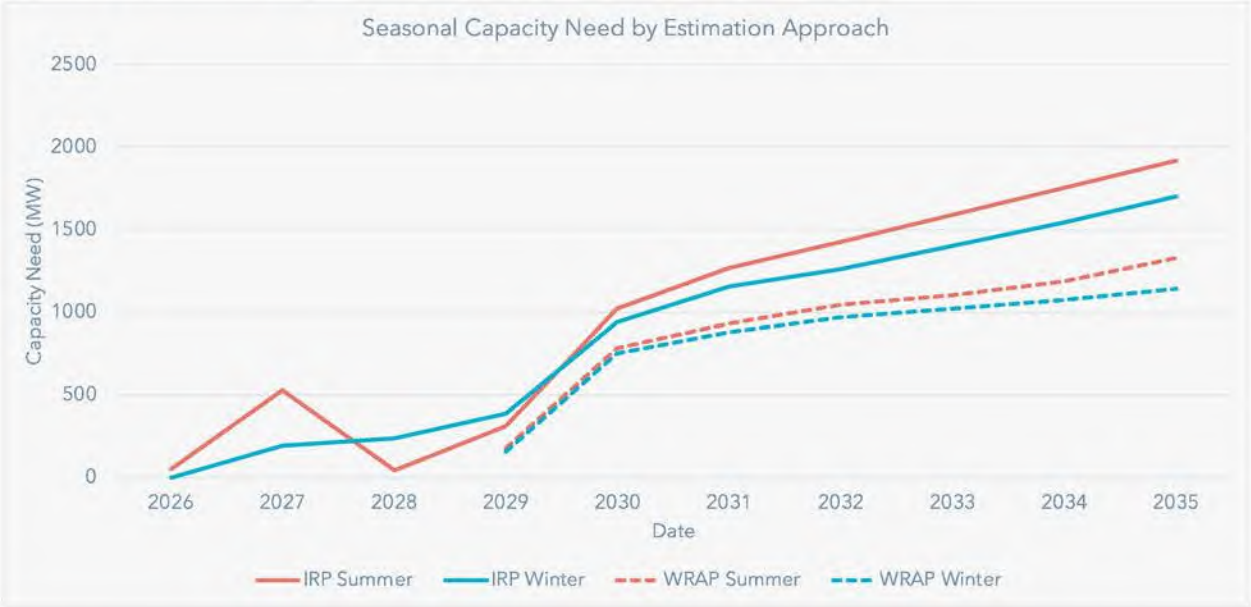
Figure 95. WRAP Based PGE Supply Stack



I.3 WRAP based capacity need

Capacity need was calculated using the difference between WRAP based forecasts of load requirements and supply, as detailed above. **Figure 96** shows the resulting capacity need as compared to the IRP derived capacity need values as estimated in Sequoia. 2030 capacity need is approximately 250 MW less using the WRAP based methods compared against the IRP estimates from Sequoia.

Figure 96. Seasonal Capacity Need by Estimation Approach



I.4 WRAP based ELCCs

PGE used ELCC estimates from WRAP's summer 2025 and winter 2025-2026 adequacy assessment for the valuation of Proxy Resources in portfolio expansion modeling. The company elected ELCC values from the +6 GW entry scenarios provided by WRAP. **Figure 97** shows a comparison of WRAP based ELCCs for the base system and +6 GW scenarios against ELCCs estimated in Sequoia for 100 MW and 2000 MW tranches. In general, summer WRAP ELCCs for storage and solar resources are significantly greater than IRP estimates for resources within the same WRAP zones. Wind resources show less divergence between the two estimation approaches, save for Gorge Wind, which has a predominantly summer generation profile.

Figure 97. Summer IRP-WRAP ELCC Comparison

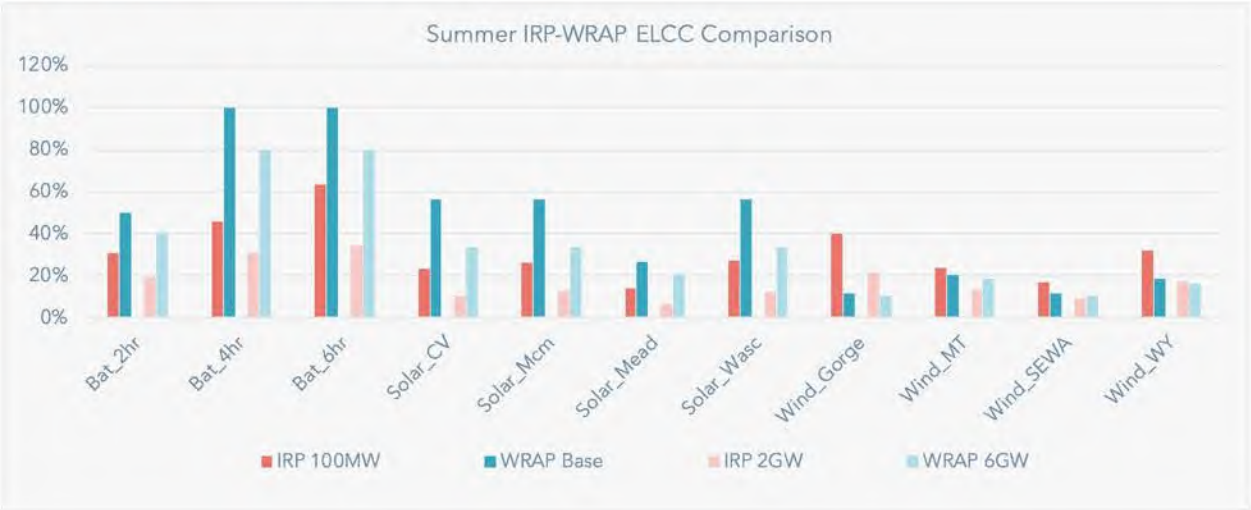


Figure 98 shows a similar comparison for the winter season. Winter WRAP ELCCs for storage resources continue to be significantly greater than IRP estimates for similar storage resources, while IRP estimates of solar and wind resources are greater.

Figure 98. Winter IRP-WRAP ELCC Comparison

For PGE's Proxy Resources without a direct overlap with WRAP ELCCs, the following assumptions were made: North Dakota Wind assigned ELCC values for WRAP Region 4 (Colorado and Wyoming), Batteries greater than 6-hour duration assigned WRAP ELCCs for 4-hour batteries, hybrids assigned the sum of WRAP based solar and 4-hr battery ELCCs, while other smaller resources (e.g., EE, DERs, CBREs) maintained ELCCs as estimated in Sequoia.

Appendix J Transmission options study

PGE CEP-IRP Update
Transmission Options Review

Energy Strategies Review of Transmission Options
Developed by PGE for CEP-IRP Update Process

January 2025

Prepared for:

PGE

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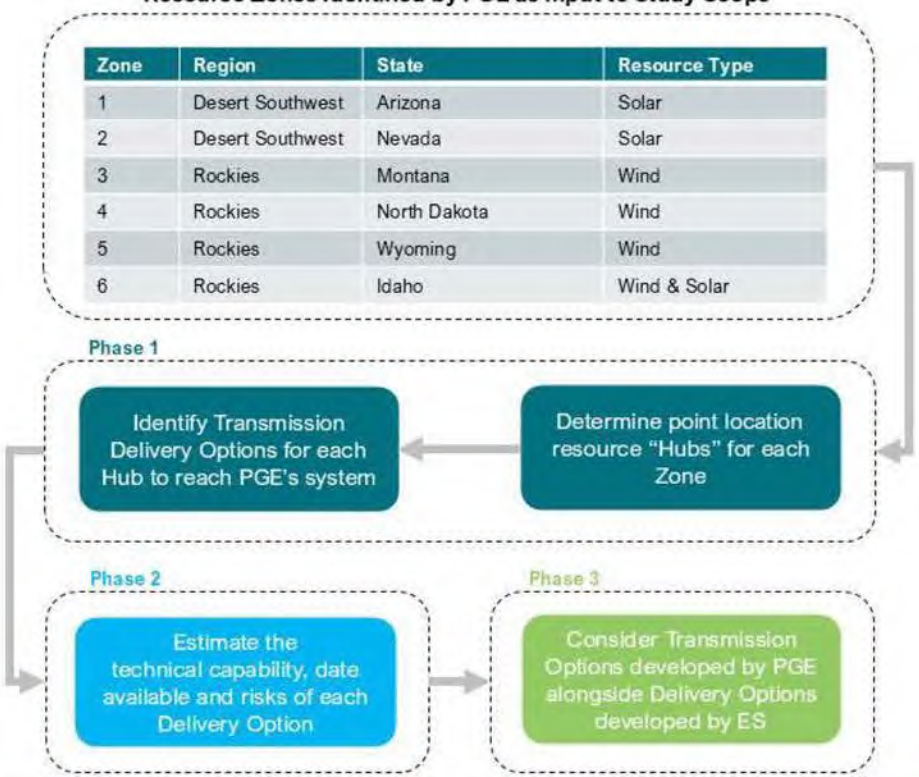
ENERGY STRATEGIES

Work Scope

- **Portland General Electric (PGE) engaged Energy Strategies (ES) to identify and evaluate transmission strategies to access remote resources.**
  - Designed to help PGE evaluate options to efficiently meet load and policy requirements in its Clean Energy Plan and Integrated Resource Plan (CEP-IRP).
- **The study consists of three phases:**
  1. **Identify Transmission Delivery Options** for six Resource Zones, considering:
     - Existing transmission system (e.g., Available Transfer Capacity (ATC))
     - Known or previously proposed transmission upgrades
     - New transmission upgrades
  2. **Characterize technical and risk profiles** of each feasible delivery option.
  3. **Review Transmission Options** developed by PGE and propose alternatives based on assessment.

Resource Zones Identified by PGE as Input to Study Scope

Zone	Region	State	Resource Type
1	Desert Southwest	Arizona	Solar
2	Desert Southwest	Nevada	Solar
3	Rockies	Montana	Wind
4	Rockies	North Dakota	Wind
5	Rockies	Wyoming	Wind
6	Rockies	Idaho	Wind & Solar



PGE | IRP Regional Transmission Study

ENERGY STRATEGIES

Transmission Delivery Options Development Methodology & Results

1 Resource Zones identified by PGE

Zone	State and Resource(s)
1	Arizona Solar
2	Nevada Solar
3	Montana Wind
4	North Dakota Wind
5	Wyoming Wind
6	Idaho Wind & Solar

2 Establish Resource Hubs

3 Review ATC Postings on OASIS

4 Include Likely Transmission Upgrades

Interim selection of Transmission Delivery Options by Energy Strategies:

State and Resource	Description	Capacity (MW)	Date Available
Arizona Solar	APS ATC + NVE Expansion + existing NWACI + PGE Rights	183	~2035-2040
	APS Upgrade + NVE Expansion + existing NWACI + PGE Rights	550	2040+
Nevada Solar	NVE Expansion + updated NWACI + Bethel Round Butte	~600	~2035-2040
	SWIP N + Gateway West 8 + B2H + new BPA TSRs	400	~2035-2040
Montana Wind	Existing PGE Rights after Colstrip retired	270	2030
	PGE rights + new BPA & possibly NWMT TSRs	~1000	~2035-2040
North Dakota Wind	North Plains Connector + PGE rights + new BPA + NWMT TSRs	~1000	~2035-2040
Wyoming Wind	Gateway West & B2H + new BPA TSRs	400	~2035-2040
Idaho Wind & Solar	Gateway West & B2H + new BPA TSRs	400	~2035-2040
	New Hemingway -> Grizzly line + Bethel Round Butte	~1000	2040+

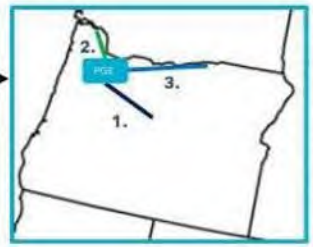
Highlighted Transmission Options Correspond to PGE Transmission Options from prior IRP roundtables

Review of PGE's Transmission Options from Prior Roundtables

- **Energy Strategies work scope included a review of Transmission Options developed by PGE:**
  - At the direction of the Oregon Public Utility Commission (PUC), PGE to update 2023 CEP-IRP Transmission Options.
  - As part of the CEP-IRP Update process and monthly public roundtables, PGE has developed 7 Transmission Options and asked Energy Strategies to review these options as a part of its broader work scope:
    1. **Are these options appropriate to meet the PUC's direction?**
    2. **What are the risks for each?**
    3. **Of the transmission alternatives identified by Energy Strategies, do any serve as viable alternatives?**

Seven Transmission Options Identified in PGE CEP-IRP Roundtables

1. Bethel-Round Butte
2. Trojan-Harborton
3. Cascade Renewable Transmission Project
4. SWIP N + Gateway West 8 + B2H
5. Western Bounty
6. North Plains Connector
7. TransWest Express



Oregon/PNW specific transmission options

As the ES work scope did not consider stand alone intra-Oregon transmission, we will provide comments but cannot propose alternatives at this time.

Remote resource transmission options

With the consideration of remote resource zones in the ES scope, we assess the viability of these transmission options and propose alternatives as needed.

ENERGY STRATEGIES

Overview of Findings from Review of PGE Transmission Options

Resource Area	PGE Transmission Option	ES Alternatives to Consider	Recommendation
North Dakota (Wind)	**North Plains Connector**	No alternatives recommended	• With PGE's Colstrip rights and NWMT + BPA TSRs, North Plains Connector is the best option. • Based on development status and need for downstream upgrades, recommend first available date no sooner than 2035 (perhaps later).
Wyoming (Wind)	**TransWest Express + CAISO**	Gateway West & B2H	• There is significant policy and pricing risk to using TransWest Express, without providing firm transmission access. • Using Gateway West may require upgrades to existing lines to increase transfer capacity.
Nevada (Solar)	**Western Bounty**	Greenlink and PGE's Rights + Upgrades	• Western Bounty likely too early in development to reach service before mid- to late-2030s. • Combining NVE's Greenlink with PGE's rights and upgrades provides a lower risk alternative to consider.
Nevada (Solar)	**SWIP N + Gateway West 8 + B2H**	No alternatives recommended	• This transmission option represents a strong option but would require additional TSRs on the BPA introducing timing risk.

- **Resource areas evaluated by ES not captured by PGE transmission options:**
  - Arizona
  - Idaho
  - Montana
- **Resource areas and transmission options in PGE CEP/IRP Roundtables outside ES scope:**
  - OR/WA/BPA
    - Bethel – Round Butte
    - Trojan – Harborton
    - Cascades Renewable Transmission
  - CAISO

PGE | IRP Regional Transmission Study

ENERGY STRATEGIES

"Evolving Grid" Status Improves Transmission Service-Driven Upgrades, but Significant Uncertainty Remains

- **BPA's Evolving Grid initiative prioritizes significant transmission projects that are critical to meet regional needs in the PNW.**
  - Initiative supports upgrades that will improve resource deliverability in the coming decade, attempting to address cyclical nature of TSRs triggering recurring upgrades in TSEP cycles and eventually dropping out.
  - Evolving Grid is designed to provide an actionable path forward primarily for projects that were identified in BPA's 2021, 2022 and 2023 TSEP processes and relate to specific TSRs.
- **Despite this step, BPA has not yet committed to constructing these projects and many still have several years of scoping, design and NEPA milestones prior to a BPA decision to fund and construct.**
  - In-service dates for EVG 1 projects: ~2026-2032.
  - In-service dates for EVG 2 projects: not announced, but possibly mid-late 2030s.
- **Conclusion for this work: Evolving Grid 1.0 projects create capacity that is likely "already spoken for" by existing TSRs (and generation projects PGE is likely aware of via RFPs) and Evolving Grid 2.0 projects have too many uncertainties to forecast impact at this time.**
  - Therefore, for this study we assume generic "new BPA TSRs" are needed for service on or through BPA to reach PGE and recommend continued monitoring of both sets of Evolving Grid projects.

Evolving Grid 1.0

1	Cross Cascades North Upgrades • Schultz-Raver 500 kV Line Upgrade • Paul 500 kV Substation Upgrade • Olympia 230 kV Substation Upgrade
2	Big Eddy-Chemawa 230/500 kV Line Upgrade
3	Portland Area Upgrades • Pearl-Sherwood McLoughlin 230 kV Line Upgrade • Keeler-Horizon 230 kV Line • Keeler 230/500 kV Transformer Addition
4	Chehalis-Covington 230 kV Line Upgrade
5	Ross-Rivergate 230 kV Line Upgrade
6	Rock Creek-John Day 500 kV Line Upgrade
7	Six Mile Canyon 230/500 kV Substation (New Construction)
8	Bonanza 230/500 kV Substation (New Construction)
9	La Pine-Bonanza 230 kV Line (New Construction)
10	Buckley 500 kV Substation Rebuild

Evolving Grid 2.0

1	Grand Coulee-Columbia-Schultz 500 kV Line Upgrade
2	Schultz-Olympia 500 kV Line Upgrade
3	North of Pearl Upgrades
4	Central Oregon 500 kV Dynamic Reactive Upgrades
5	RATS: Reno-Alturas Reactive Addition
6	Salem Area Upgrades #1 (North of Marion)
7	Salem Area Upgrades #2 (North of Marion)
8	NOB Substation (New Construction)
9	Lower Columbia-Bonanza 500 kV Line (New Construction)
10	Bonanza to NOB 500 kV Line (New Construction)
11	Ostrander-Pearl 500 kV Line Upgrade
12	Big Eddy-Quenett Creek Upgrade
13	Big Eddy-The Dalles Line Rebuild

Review of PGE Proposed Transmission Options and Selected Alternatives

ENERGY STRATEGIES

PGE Transmission Options Review – Overview of Contents

1. **PGE Transmission Options to access remote resources:**
   - SWIP N + Gateway West 8 + B2H
   - Western Bounty
   - North Plains Connector
   - TransWest Express Transmission Project

2. **Appendix: PGE Transmission Options specific to Oregon/PNW:**
   1. Bethel – Round Butte 500kV Upgrade
   2. Trojan – Harborton Upgrade
   3. Cascades Renewable Transmission Project

SWIP N + Gateway West 8 + B2H

Details from PGE's CEP-IRP Update Roundtable:

- *This option entails PGE purchasing access on five transmission lines leading to the desert southwest:*
  1. *Boardman to Hemingway (B2H)*
  2. *Gateway West segment E8*
  3. *Southwest Intertie Project (SWIP) – North*
  4. *One Nevada Transmission Line (ON Line)*
  5. *Desert Link*
- *This is achievable by **2027** (line COD). However, this option would require additional access across BPA's system, which is plausibly expected by **2032** (IRP COD).*
- *Up to **600 MW** of Nevada solar is modeled to be enabled through this option.*

SWIP N + Gateway West 8 + B2H:

- **Energy Strategies' conclusions:**
  - SWIP N + Gateway West 8 + B2H is a viable transmission option to access Nevada generation – it involves transactions with three transmission providers: 1. NVE, 2. PacifiCorp or Idaho Power, and 3. BPA.
  - Up to 400 MW of Nevada solar can be accessed, with unallocated transmission capacity on B2H as the limiting segment (see details on next slide).
  - Boardman (Longhorn) to PGE requires additional TSRs on the BPA system.
  - Earliest Date: 2035-2040, with greatest timing risk related to receiving additional TSRs on BPA system and availability of capacity on B2H.

SWIP N + Gateway West 8 + B2H: Details

- **Energy Strategies' determination of rights on each segment:**

Segment	Description	Rights MW	Est. Date Available
NVE	ATC from Greenlink projects (Southsys to Northsys)	~550 (1)	2029
SWIP North	Utilizing DOE's northbound entitlements	500 (2)	2027 COD
Gateway West E8	Utilizing forecasted available transmission	600 (3)	2028 COD
B2H	Use currently unallocated 218MW of PAC rights and 182MW of IPCo rights	400 (4)	2026 COD
Longhorn to PGE	New BPA TSRs – see prior slides	400	2035-2040
	Rights and Date Available entire path:	**400**	**2035-2040**

SWIP N + Gateway West 8 + B2H:

(1) ATC from OASIS Postings, Southsys to Northsys, 550MW represents minimum during 2029-2033 period (Expansion entails Greenlink West, Greenlink North).
(2) For SWIP-North, CAISO and the DOE hold a combined 1072.5 MW of entitlements in the northbound direction. We assume that PGE could request and acquire up to 500 MW (equal to DOE's entitlements) (sources: here and here).
(3) Gateway West Segment E8 will have a transfer capacity of 2000 MW. Energy Strategies assumes PGE can request and receive 600 MW of capacity (source: PacifiCorp here).
(4) From IPCO for B2H (CPCN documents filed by IPCO here and here).

Western Bounty

Details from PGE's CEP-IRP Update Roundtable:

- *The Western Bounty Transmission System is a proposed 3000 MW HVDC line that could connect southern California to the Grizzly substation*
- *The projected commercial operation date (COD) is **2033***
- *Up to **3000 MW** of Nevada solar is modeled to be enabled through this option*
- *This option would provide access to the SP-15 market hub*
- *Additional BPA upgrades would be required for this option to reach PGE*

Western Bounty

- **Energy Strategies' conclusions:**
  - Western Bounty early in its development cycle and unlikely to materialize before mid- to late-2030s based on historical transmission development rates.
    - Development started in 2023 with the Interregional Transmission Project (ITP) joint evaluation process only starting in 2024. Project is early stage.
  - The scope, timing and available capacity of necessary BPA upgrades would likely limit PGE's 3000 MW of proposed solar access to a smaller amount – we do not recommend assuming 3000 MW of availability.
  - As an alternative, NVE's Greenlink expansion that increases ATC on their system, together with PGE's rights on the Northwestern AC Intertie (NWACI) and the Bethel – Round Butte upgrade, could be utilized to access resources within a similar proposed timeframe (details provided on next slide).

ENERGY STRATEGIES

Western Bounty Alternative: NVE Expansion and PGE rights

- **NVE Greenlink expansion and PGE's rights and projects as an alternative to Western Bounty for access to southwest solar:**
  - With NVE's Greenlink expansion, Southsys to Northsys capacity increases, creating additional ATC which PGE can utilize.
  - Pros:
    - Less risk in terms of parties involved and permitting timelines: NVE taking lead on "Greenlink 3" (Fort Churchill -> Captain Jack).
    - The expected route for Greenlink 3 roughly falls within the "Mountain – Northwest" National Interest Electric Transmission Corridor meaning any environmental review process under NEPA could be expedited as part of DOE's National Transmission Needs Study.
  - Cons:
    - Available capacity is less than considered with Western Bounty, however the 3000 MW envisioned capacity on Western Bounty would be limited by BPA upgrades.
- **Conclusion: Less risk and same desired timeframe and capacity potential as Western Bounty.**

Greenlink vs. Western Bounty:

ID	Element	Description	Rights MW	Est. Date Available
1	NVE	ATC from Greenlink projects (Southsys to Northsys)	~550 (1)	2029
2	Greenlink 3	Fort Churchill -> Captain Jack (early stage proposed by NVE)	725 (2)	2035-2040
3	Captain Jack -> Grizzly	Planned contractual updates to allow intra-region scheduling on the Northwest AC Intertie (NWACI) and use PGE's existing rights.	627 (3)	2029
4	Bethel – Round Butte Upgrade	TTC depends on configuration but not limiting segment in path	~3000 (4)	2032
		Rights and Date Available entire path:	**627**	**2035-2040**

(1) ATC from OASIS Postings, Southsys to Northsys, 550MW represents minimum during 2029-2033 period (Expansion entails Greenlink West, Greenlink North).
(2) NVE IRP Filing on initial study work related to Fort Churchill -> Captain Jack (Greenlink 3) (sources: here and here)
(3) Data from PGE.
(4) Data from PGE.

North Plains Connector

Details from PGE's CEP-IRP Update Roundtable:

- *This project is a 412-mile HVDC transmission line to be constructed with endpoints near Bismarck, North Dakota and Colstrip, Montana.*
- *PGE currently has **270 MW** of rights from Colstrip to PGE.*
- *If nothing changes between now and 2032, only a combined 270 MW NPC will be available for model selection.*
- *However, the company has submitted TSRs for an additional 720 MW across both BPA's and NorthWestern's systems.*
- *Up to 3000 MW of North Dakota wind is modeled to be enabled through this option, subject to the constraints mentioned above.*
- *Additionally, this option would provide access to the MISO Resource Zone 1 market.*
- *This option's COD is expected by **2032**.*

North Plains Connector:

- **Energy Strategies' conclusions:**
  - With PGE's existing rights from Colstrip, this project represents the best option to access North Dakota wind.
  - However, the timing to receive requested BPA and NWMT TSRs, as well as early stage of project development, are not consistent with a 2032 availability - we suggest a late 2030s timeframe may be more appropriate given historical greenfield transmission development timelines.
  - As already noted above, the actual MW capacity of access will be limited by PGE rights from Colstrip and pending TSRs.

TransWest Express Transmission Project

Details from PGE's CEP-IRP Update Roundtable:

- *This project is a two-part line that connects near Sinclair, WY and near Boulder City, NV:*
  - *Near Sinclair, WY to near Delta, UT: 3000 MW DC*
  - *Near Delta, UT to near Boulder City, NV: 1500 MW AC*
- *This option is being structured as a gen-tie through CAISO, which PGE can access using its rights at the California-Oregon Border (COB) trading hub.*
  - *This line could add up to approximately 3,000 MW of transmission access, however PGE's COB rights limit access to 600 MW of Wyoming Wind.*
  - *No other market access benefits assumed.*
- *The anticipated COD for this option is 2027 and would not require any additional transmission expansion.*

TransWest Express Transmission Project:

- **Energy Strategies' conclusions:**
  - PGE would need to be a subscriber on TWE and deliver to Eldorado; then make a market purchase at California Oregon Border (COB) which may be subject to paying CAISO transmission access charge (TAC).
    - This strategy would also be subject to basis risk between Eldorado and COB (or require a developer to carry this risk).
    - Would also likely need to ensure the transaction was designated as a high priority wheel-through.
    - This results in potentially high cost of transmission to access WY wind.
  - Other factors to consider include CAISO LSEs obtaining all TWE capacity (for reliability/clean energy needs), lack of ability to document delivery to PGE given lack of firm service, significant policy risk and dependence on CAISO market rules.
  - An alternative using Gateway West and B2H may be viable but has risks in timing and availability of capacity.

ENERGY STRATEGIES

TransWest Express Alternative: Utilizing Gateway

- **Utilizing the Gateway buildout as an alternative to TransWest Express for access to Wyoming wind:**
  - Pros:
    - Provides access to Wyoming wind on a firm basis while avoiding the policy and pricing risks that would be associated with CAISO market transactions.
  - Cons:
    - Puts PGE in competition with PAC and IPCo and would require timely granting of TSRs on all systems.
- **Conclusions: Neither TransWest Express nor the Gateway alternative are ideal options**
  - PGE may be unable to secure affordable transmission access to Wyoming wind on a firm basis in the 2030s.

Gateway West vs. Transwest Express:

ID	Element	Description	Rights MW	Est. Date Available
1	Gateway West: Anticline -> Populus	Completing construction of Gateway West segment D-3	400 (1)	2031
2	Gateway West: Populus -> Hemingway	Completing construction of Gateway West segment E	400 (1)	2036
3	B2H	Use currently unallocated 218MW of PAC rights and 182MW of IPCo rights	400 (2)	2026 COD
4	Longhorn to PGE	New BPA TSRs.	400	2035-2040
		Rights and Date Available entire path:	**400**	**2035-2040**

(1) Gateway West segment E8 will have a transfer capacity of 2000 MW. Energy Strategies assumes PGE can apply for 400 MW of capacity (source: PacifiCorp here).
(2) (2) From IPCO for B2H (sources: IPCO here and here).

Appendix: Review of PGE Oregon/PNW Specific Transmission Options

PGE | IRP Regional Transmission Study

Bethel – Round Butte 500kV Upgrade

Details from PGE's CEP-IRP Update Roundtable:

- *The Bethel-Round Butte reconductoring would increase the capacity on the existing line.*
- *The line is 98 miles, running from the Bethel substation (near Salem) to the Round-Butte substation.*
- *The projected commercial operation date (COD) is **2032** and will not require any other transmission expansion for PGE to access these benefits.*
- *Rebuilding the line from 230 kV to 500 kV will increase capacity.*
- *This could support an increase of **2,385-4,770 MW** increase in 'BPA' resources (off-system resources in the PNW region), depending on specification and subsequent path rating processes.*
- *This option provides market access to the California-Oregon border.*

Bethel – Round Butte 500kV Upgrade:

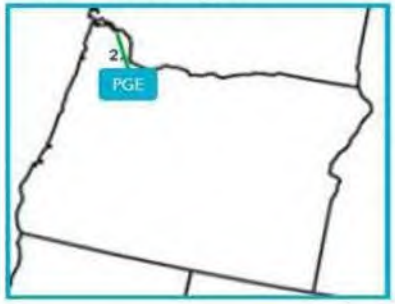
- **Energy Strategies' conclusions:**
  - As noted in the PGE 2023 CEP/IRP this upgrade is a "no regrets" option and facilitates significant access to queued resources.
  - However, depending on the reconductoring configuration chosen, the total transfer capacity is likely to reach only 3000 MW.

Trojan – Harborton Upgrade

Details from PGE's CEP-IRP Update Roundtable:

- Approximately 34 miles long, running between PGE's Trojan and Harborton substations, paralleling two existing lines in service since the 1970s.
- PGE currently owns the additional unused ROW necessary for the project and has since the 1970s.
- The projected commercial operation date (COD) is **2032** and will not require any other transmission expansion for PGE to access these benefits.
- This transmission project will enable **800 MW** from BPA's generation resources, subject to cooperative study and agreement with other South of Allston path owners, BPA and PacifiCorp.

Trojan – Harborton Upgrade:



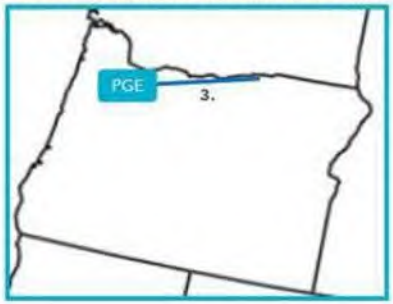
- **Energy Strategies' conclusions:**
  - With the importance of South of Allston and the control over right of way and facilities PGE possesses which are necessary to complete this upgrade, completing Trojan – Harborton upgrades appears "no regrets" similar to the Bethel – Round Butte upgrade.
  - In addition to the mentioned need to coordinate with other South of Allston path owners, timing of benefits from this upgrade is not certain:
    - Realizing the 800MW of BPA generation resources seemingly requires receipt of TSRs PGE has applied for on the BPA system and likely date to receive these TSRs is closer to 2035 than the proposed 2032 COD of this upgrade option.

Cascade Renewable Transmission Project

Details from PGE's CEP-IRP Update Roundtable:

- This project involves an electric transmission cable bundle, buried entirely underground and underwater, along with two converter stations located next to existing substations.
- This travels approximately 100 miles, primarily beneath the Columbia River, from the Big Eddy substation to the Harborton substation.
- The projected commercial operation date (COD) is **2032** and will require additional BPA and PGE transmission expansion for PGE to access these benefits.
- This is modeled to enable the transfer of **1,100 MW** of 'BPA' resources (off-system resources in the PNW region).
- PGE is not currently participating in this project, but involvement may be possible if selected as part of PGE's preferred portfolio.

Cascade Renewable Transmission Project:



- **Energy Strategies' conclusions:**
  - The point of delivery at Harborton makes PGE well-positioned to realize benefits from access to BPA resources.
  - The timing for 1260 MW of solar + storage projects in BPA's Queue at Big Eddy as well as the Cascade Renewable Transmission Project's own queue position (all seeking interconnection/energization in 2029) seems aggressive given the early stage of development for this project.
    - With the challenges to work in the Columbia River, especially from a permitting perspective, late 2030s more likely as a time for project COD.

PGE Corporate Headquarters
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Attachment 9. Cascade Renewable Transmission Comments Filed in OPUC Docket LC80

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 80

In the Matter of PORTLAND GENERAL ELECTRIC CO., 2023 Integrated Resource Plan and Clean Energy Plan.	COMMENTS OF CASCADE RENEWABLE TRANSMISSION, LLC

Cascade Renewable Transmission, LLC ("CRT") appreciates the opportunity to provide comments to the Staff's Round 2 Comments and Recommendations. CRT is developing an 1100 MW HVDC transmission interconnection between BPA's Big Eddy substation and Portland General Electric's ("PGE") Harborton substation, the Cascade Renewable Transmission Project ("CRTP"). CRT has filed a Notice of Intent to File an Application for a Site Certificate ("NOI") with the Oregon Department of Energy ("ODOE"), and the NOI is the subject of a Project Order issued July 25, 2023; both the NOI and the Project Order are publicly available for review through the ODOE website.

As noted throughout PGE's Integrated Resource Plan ("IRP") and PGE's Reply Comments, there is a growing and significant need for incremental transmission for PGE to be able to secure sufficient renewable energy resources to meet its GHG requirements in 2030 and beyond as well as reliably serve load growth driven by electrification and new industry. Additionally, there is general consensus, perhaps too obvious to mention, that significant new transmission capacity requires long lead times, suggesting that for the purpose of meeting GHG

requirements, 2030 is just around the corner.

Table 7 in PGE's July 7th addendum filing identifies an estimated transmission need in MW of 1,051 by 2029, 1,658 by 2030 and 4,568 by 2035. In PGE's Responses to Round 1 Comments filed on September 6th, PGE indicated "There is not a location on the BPA system, or beyond, to site generation that does not have an impact on South of Allston flowgate. This is because of Power Transfer Distribution Factor (PTDF), which refers to the distribution of power flows on the networked transmission system." CRT appreciates the material concern raised by PGE and agrees the South of Allston ("SOA") flowgate constraint needs to be addressed in order for PGE to be able procure off system resources. It should further be noted, however, that PTDFs also impact flows from potential new off system renewable resources on the constrained Cross Cascade South ("CCS") flowgate[1], and will impact flows on the newly to be implemented and constrained North of Pearl ("NOPE") flowgate[2].

In its recently released draft Longer Term Local Transmission Plan, PGE expressed its concerns about the NOPE flowgate stating, "During the heat event in June 2021… PGE's system experienced flows never seen before during peak summer conditions, at least partially due to the importing of generation from California. The PGE Transmission System experienced heavy south-to-north flow from the Sherwood area to the Beaverton/Hillsboro area..."[3] The "never seen before" south-to-north flows from the Sherwood area to the Beaverton/Hillsboro area are driving the need for the NOPE flowgate. PGE further acknowledged that the issue still exists and if anything is getting worse when they stated, "Subsequent summers have experienced this flow pattern with

[1] In PGE's Comments filed on September 6th, PGE noted "The Cross Cascade South Path is the same as BPA flowgate known as West of Cross Cascade South (WOCS). The WOCS is currently known to be constrained and is viewed by some commenters in this docket as PGE's biggest obstacle to delivering new resources to company loads".
[2] In PGE's Comments filed on September 6th, PGE stated "It is worth noting that this calculator does not yet include the modifications necessary to account for the new BPA flowgates that are currently being implemented and impact PGE, including the North of Pearl flowgate (NOPE)…"
[3] PGE's Longer Term Local Transmission Plan for the 2023-2024 Planning Cycle, Draft – November 10, 2023, page 7.

increasing intensity and the Hillsboro area continues to see increased load demands, necessitating a continued focus on studying power flow into the area that was first experienced in the previously mentioned 2021 heat event."[4]

Exhibit 1, attached hereto, shows the results of BPA's PTDF analysis for 100 MW of energy deliveries to PGE's service territory (BPAT PGE) from three different BPA substations east of the Cascades: Maupin (Central Oregon), Slatt (near Boardman) and Vantage (near Mid-C). The three point of receipt substations for the energy deliveries were selected to give a diverse view of PGE's ability to procure resources broadly across BPA's system, including Montana and Wyoming wind delivered into Boardman across the new B2H transmission line. In all three cases, the 100 MW of energy delivery showed material impact on the constrained SOA, CCS and NOPE[5] flowgates. Based on this analysis, for PGE to procure significant incremental off system renewable resources and have them deliverable to PGE's load, particularly to rapidly growing load near Beaverton/Hillsboro, PGE will most likely need to resolve constraints on all three flowgates: SOA, CCS, and NOPE.

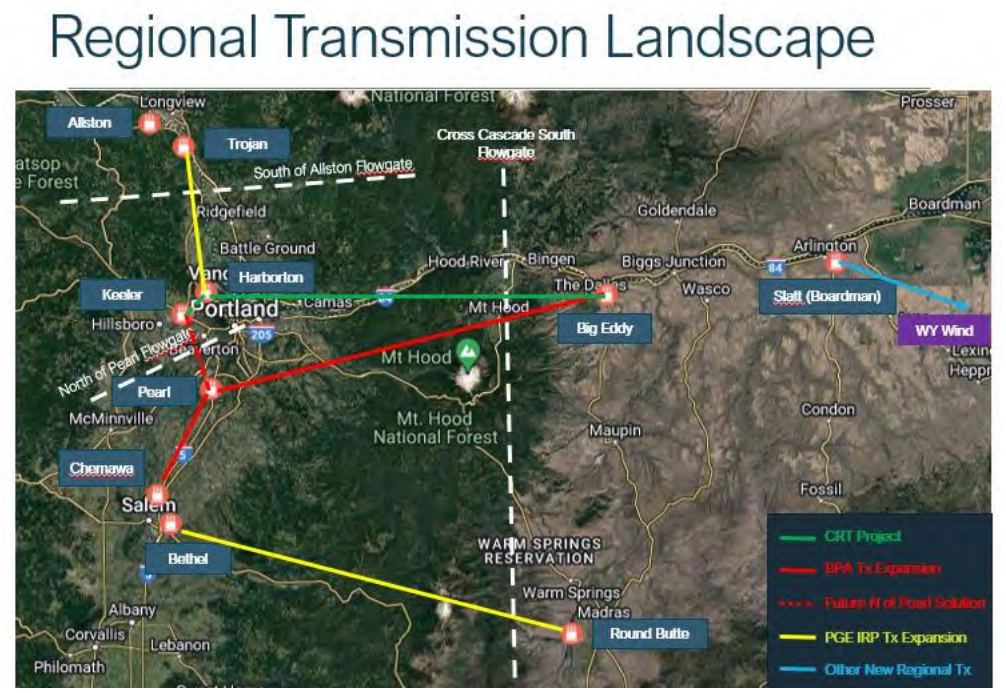
CRT performed another BPA Power Transfer Distribution Factor analysis from those same three substations as the point of receipt, but this time used Big Eddy as the point of delivery. Big Eddy is the location for CRTP's eastern converter station. The results of this analysis are shown in Exhibit 2. With Big Eddy as the point of delivery, there are no material impacts on CCS or NOPE and only in the case of sourcing from the Vantage substation is there an impact on SOA. As shown in Exhibit 2, the impact on the SOA flowgate is estimated by BPA to be 12.7 MW. CRT has performed a separate analysis of the anticipated impact on SOA with a 100 MW CRTP injection at PGE's Harborton substation. This analysis indicated an approximate 20 MW relief to

[4] PGE's Longer Term Local Transmission Plan for the 2023-2024 Planning Cycle, Draft – November 10, 2023, page 8.
[5] BPA began including the NOPE flowgate in the calculator for power transfer distribution factors in October 2023.

the SOA flowgate in the N-S direction. So, on a net basis, there should not be a material impact on SOA with 100 MW sourced from Vantage, delivered to Big Eddy and in turn delivered into Harborton utilizing CRTP.

The white dashed lines in Figure 1 below show the general location of the constrained SOA, CCS and NOPE flowgates. The yellow lines show two transmission lines proposed in PGE's Draft Longer Term Local Plan for the 2023-2024 Planning Cycle issued on November 10, 2023; one a double circuit 230 KV line from Harborton to Trojan and the other converting the 91 mile 230 KV Bethel to Round-Butte line to 500 KV. The combination of the two new PGE transmission lines would in some manner address the constraints on SOA and CCS. Figure 1 also shows with the red line the general route of BPA's proposed upgrade of the Big Eddy to Chemawa 230 KV line, which will loop into the Pearl 500kV and Ostrander 500kV substations. This upgrade would also address the constraints on CCS. Finally, there is a dashed red line from the Pearl Substation to the Keeler substation. This is simply to reflect something, most likely a new 500kV transmission line, which will be required to resolve the newly constrained NOPE flowgate. The blue line shows the general route of the B2H transmission line for accessing MT and WY wind. In summary, because of the implications of PTDFs across the networked AC system, PGE's SOA solution, plus a NOPE solution plus either BPA's or PGE's CCS solution will most likely be required for PGE to be able to access significant incremental off system renewable resources east of the Cascades and serve growing load in Beaverton/Hillsboro.

Figure 1



The green line in Figure 1 shows the location of the proposed Cascade Renewable Transmission Project. It is designed to run DC from BPA's Big Eddy substation directly into PGE's Harborton substation. By landing in PGE's Harborton substation, CRTP addresses the CCS constraint while bypassing the SOA and NOPE flowgates. In fact, electricity flows on CRTP injected at the Harborton substation would actually "push back on" and relieve some of the constraints on SOA and NOPE. Therefore, in the context of serving the growing load in Beaverton/Hillsboro and meeting the HB2021 requirements in 2030 and beyond, CRTP should be viewed as complementary to building the combination of PGE's SOA solution, plus a NOPE solution, plus either BPA's or PGE's CCS solution; one line instead of three.

In the OPUC Staff Round 2 Comments and Recommendations, Staff acknowledges the general need for transmission but cautions more analysis is needed to define the specific solutions

when it states, "Staff does not undermine the need for transmission resources in general, but believes that additional analysis is needed to evaluate potential value of on-system distributed energy resources, alternative transmission strategies, and a clear description of options that PGE says it will pursue for the SoA line."[6] CRT agrees with this view and we encourage the Commission to request PGE to include CRTP in any analysis of transmission alternatives. It is very important that in any transmission analysis performed by PGE, up-to-date cost estimates, including required system upgrades, are utilized for all potential transmission solutions. PGE indicated "the company continues to rely on the 2018 report "Relative Costs of Transporting Electrical Chemical Energy" to form the basis of the transmission proxy costs in the CEP/IRP."[7] Given the dramatic price escalation which has occurred since 2018 for the cost of energy infrastructure, the cost estimates utilized by PGE in its IRP could be 30-50% below a reasonable estimate prepared today. Accounting for system upgrade costs is also very important. CRT has completed its WECC Phase 2B path rating and is in the process of finalizing its facilities studies as part of its request to interconnect at each of the BPA and PGE substations. This gives CRT very good visibility into the scope and cost of incremental system upgrades which will be required to reliably integrate CRTP into the overall AC grid. To compare various transmission solutions on an equal basis, the costs of all required system upgrades should also be considered.

In addition to costs, the Commission should also direct PGE to evaluate <u>all</u> potential benefits of the various transmission solutions. For instance, BPA's Big Eddy to Chemawa upgrade and PGE's Bethel to Round Butte upgrade are expansions of overhead 230 KV lines to 500 KV lines in existing ROWs through high wildfire risk areas of the Cascade Mountains. In contrast, CRTP is a DC line buried for its entire route underground or under the Columbia riverbed using

[6] OPUC Docket LC 80 – Staff Round 2 Comments and Recommendations filed October 24, 2023, page 15.
[7] PGE Reply to Round 1 Comments filed on September 6, 2023, page 24.

well-established installation technology. CRTP's underwater installation avoids wildfire risk. As another example, a voltage source converter DC line such as CRTP can offer important system benefits compared with an AC line, such as black start capability and VAR support. It would also be worthwhile for PGE as part of its transmission analysis to lay out an expected timeline for every transmission alternative being considered. Key milestones for the timeline could include: (1) expected date of completing WECC path rating and system impact studies to better define the true scope and cost of the transmission project; (2) expected date of having all key State and Federal permits filed; (3) expected date of receiving all permits; (4) anticipated start date for construction; and (5) anticipated commercial operation date. This would help lay out a framework to better understand which transmission lines have a realistic possibility of being available to meet HB2021 2030 requirements and which are better alternatives to be considered for meeting the requirements of 2040 and beyond.

Lastly, the Staff recommends, "The Commission direct PGE to include a report on federal incentive implementation and its key impacts on the Company's Action Plan and 2030 resource strategy with its next IRP/CEP Update."[8] The availability of federal incentives for transmission investment through the Infrastructure Investment and Jobs Act and the Inflation Reduction Act are unprecedented. CRT commends PGE's partnership with the Confederated Tribes of the Warm Springs Reservation Oregon ("CTWS") and the receipt of a federal funding award. As part of the Bipartisan Infrastructure Law, Funding Opportunity Announcement for Grid Resilience and Innovation Partnerships recently released on November 13, 2023 ("FOA"), the DOE indicated the available funding is "…a unique chance to build partnerships between states, local governments, Tribes and power system operators that align industry objectives with broader regional, interregional and national goals to enhance reliability, all-hazards resilience and efficiency of the

[8] OPUC Docket LC 80 – Staff Round 2 Comments and Recommendations filed October 24, 2023, page 32.

electric grid".[9] The FOA goes on to indicate the DOE particularly seeks "Projects that demonstrate meaningful public/private partnership approaches through strategic involvement of *both* public and private sector actors."[10] For this reason, CRT believes a partnership among CRT, PGE and the State of Oregon would be a winning combination for another federal funding award for the region. CRT believes this partnership could be implemented in a way that would not conflict with either the OPUC's process and requirements for selecting transmission projects for cost recovery or the permitting requirements of Oregon Energy Facility Siting Council and other state and federal agencies.

While it may be too early in the process to select which transmission lines provide the best system benefits and value for ratepayers, it is not too early for the Commission to at a minimum acknowledge new transmission lines will be required to meet the requirements of HB2021. This acknowledgment by the Commission will help focus the PNW energy community on implementing transmission solutions for the region.

As demonstrated in PGE's IRP, to meet load growth and the requirements of HB2021, it is highly likely that several new transmission projects will need to be constructed. There is little downside risk and potentially strong benefits to encouraging the consideration and reasonable pursuit of as many transmission options as possible. While it may be impossible today to determine which proposed new transmission lines or transmission line upgrades can be developed successfully and on a timely basis, a "just-in-time approach" to transmission development cannot be a successful path forward. Rather, at this stage, every potentially viable transmission project should be encouraged to proceed with development.

Thank you for the opportunity to provide comments and please contact the undersigned

[9] Funding Opportunity Announcement issued November 13, 2023, page 3.
[10] Funding Opportunity Announcement issued November 13, 2023, page 20.

with any questions you may have.

Dated this 21st Day of November, 2023.

Respectfully submitted,

/s/ Jeffrey Wood

Vice President
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Exhibit 1

BPA's Power Transfer Distribution Factors for 100 MW of energy deliveries from Maupin substation (Central Oregon), Slatt substation (near Boardman) and Vantage substation (near Mid-C) to PGE's service territory (BPAT PGE).[11]

- Deliveries to BPAT PGE from each of those three substations show significant MW impacts on SOA (14.0 – 27.2), CCS (64.6 – 72.7) and NOPE (24.6 – 32.3)[12]

		Zone	kV	Owner Name
Evaluated Source:	MAUPIN	Lower Columbia Basin	230	Bonneville Power Admin
Evaluated Sink:	BPAT.PGE	NA	NA	NA
Request MW:	100			

Posted 10/18/23

Sub Grid Constrained Area:	BIG EDDY/MAUPIN 230	PORTLAND AREA
PTDF #:	40709	321

Flowgate	Source	Sink	% Impact	MW Impact	Result
CROSS CASCADES NORTH E>W	-0.1607	-0.2985	13.8%	13.8	Potential LTF
CROSS CASCADES SOUTH E>W	0.1024	-0.6132	71.6%	71.6	Study for CFS
NORTH OF HANFORD N>S	-0.6171	-0.5054	-11.2%	0.0	Potential LTF
RAVER-PAUL N>S	-0.1035	-0.1971	9.4%	9.4	Potential LTF
SOUTH OF ALLSTON N>S	-0.1659	-0.3056	14.0%	14.0	Study for CFS
NORTH OF PEARL S>N	0.0846	-0.2311	31.6%	31.6	Study for PoS
WEST OF JOHN DAY E>W	-0.2866	-0.2094	-7.7%	0.0	Potential LTF
WEST OF SLATT E>W	-0.1853	-0.1331	-5.2%	0.0	Potential LTF
WEST OF LOWER MONUMENTAL E>W	-0.0597	-0.0569	-0.3%	0.0	Potential LTF
SOUTH OF CUSTER N>S	-0.0021	-0.0067	0.5%	0.5	Potential LTF
NORTH OF ECHO LAKE S>N	0.0439	0.0471	-0.3%	0.0	Potential LTF
WEST OF MCNARY E>W	-0.1475	-0.1233	-2.4%	0.0	Potential LTF
WEST OF HATWAI E>W	0.0503	0.0431	0.7%	0.7	Potential LTF
NORTH OF GRIZZLY N>S	0.1097	-0.0233	13.3%	13.3	Potential LTF

[11] BPA PTDF Calculator Effective 10/18/2023.

[12] Anything high-lighted in yellow is viewed by BPA as being an immaterial impact on the flowgate.

		Zone	kV	Owner Name
Evaluated Source:	SLATT	Lower Columbia Basin	500	Bonneville Power Admin
Evaluated Sink:	BPAT.PGE	NA	NA	NA
Request MW:	100			

Posted 10/18/23

Sub Grid Constrained Area:		PORTLAND AREA
PTDF #:	40989	321

Flowgate	Source	Sink	% Impact	MW Impact	Result
CROSS CASCADES NORTH E>W	-0.1315	-0.2985	16.7%	16.7	Potential LTF
CROSS CASCADES SOUTH E>W	0.1139	-0.6132	72.7%	72.7	Study for CFS
NORTH OF HANFORD N>S	-0.6623	-0.5054	-15.7%	0.0	Potential LTF
RAVER-PAUL N>S	-0.0835	-0.1971	11.4%	11.4	Study for CFS
SOUTH OF ALLSTON N>S	-0.1350	-0.3056	17.1%	17.1	Study for CFS
NORTH OF PEARL S>N	0.0922	-0.2311	32.3%	32.3	Study for PoS
WEST OF JOHN DAY E>W	0.1935	-0.2094	40.3%	40.3	Potential LTF
WEST OF SLATT E>W	0.5072	-0.1331	64.0%	64.0	Potential LTF
WEST OF LOWER MONUMENTAL E>W	-0.0749	-0.0569	-1.8%	0.0	Potential LTF
SOUTH OF CUSTER N>S	-0.0009	-0.0067	0.6%	0.6	Potential LTF
NORTH OF ECHO LAKE S>N	0.0431	0.0471	-0.4%	0.0	Potential LTF
WEST OF MCNARY E>W	-0.1939	-0.1233	-7.1%	0.0	Potential LTF
WEST OF HATWAI E>W	0.0410	0.0431	-0.2%	0.0	Potential LTF
NORTH OF GRIZZLY N>S	0.0586	-0.0233	8.2%	8.2	Potential LTF

		Zone	kV	Owner Name
Evaluated Source:	VANTAGE	Central Washington	230	Bonneville Power Admin
Evaluated Sink:	BPAT.PGE	NA	NA	NA
Request MW:	100			

Posted 10/18/23

Sub Grid Constrained Area:		PORTLAND AREA
PTDF #:	41111	321

Flowgate	Source	Sink	% Impact	MW Impact	Result
CROSS CASCADES NORTH E>W	-0.0364	-0.2985	26.2%	26.2	Potential LTF
CROSS CASCADES SOUTH E>W	0.0327	-0.6132	64.6%	64.6	Study for CFS
NORTH OF HANFORD N>S	0.0025	-0.5054	50.8%	50.8	Potential LTF
RAVER-PAUL N>S	-0.0195	-0.1971	17.8%	17.8	Study for CFS
SOUTH OF ALLSTON N>S	-0.0332	-0.3056	27.2%	27.2	Study for PoS
NORTH OF PEARL S>N	0.0150	-0.2311	24.6%	24.6	Study for PoS
WEST OF JOHN DAY E>W	-0.0033	-0.2094	20.6%	20.6	Potential LTF
WEST OF SLATT E>W	0.0085	-0.1331	14.2%	14.2	Potential LTF
WEST OF LOWER MONUMENTAL E>W	-0.0456	-0.0569	1.1%	1.1	Potential LTF
SOUTH OF CUSTER N>S	-0.0054	-0.0067	0.1%	0.1	Potential LTF
NORTH OF ECHO LAKE S>N	0.0310	0.0471	-1.6%	0.0	Potential LTF
WEST OF MCNARY E>W	0.0218	-0.1233	14.5%	14.5	Potential LTF
WEST OF HATWAI E>W	0.0189	0.0431	-2.4%	0.0	Potential LTF
NORTH OF GRIZZLY N>S	0.0069	-0.0233	3.0%	3.0	Potential LTF

Exhibit 2

BPA's Power Transfer Distribution Factors for 100 MW of energy deliveries from Maupin substation (Central Oregon), Slatt substation (near Boardman) and Vantage substation (near Mid-C) to Big Eddy substation, the location of CRTP's eastern converter station.[13]

- Deliveries to Big Eddy show no MW impact on the currently constrained CCS and NOPE and only in the case of deliveries from Vantage is there an impact on SOA in the amount of 12.7 MW. However, CRT's analysis indicates a 100 MW injection at Harborton would have an approximately 20 MW benefit on SOA, so on a net basis, with CRTP there should not be a material impact on SOA.

With CRTP, PGE should be able to procure resources from Maupin, Slatt and Vantage and have them delivered to PGE's service territory without the need to upgrade SOA, CCS or NOPE.

			Zone	kV	Owner Name
Evaluated Source:	MAUPIN		Lower Columbia Basin	230	Bonneville Power Admin
Evaluated Sink:	BIGEDDY		Lower Columbia Basin	500	Bonneville Power Admin
Request MW:	100				
Posted 10/18/23					
Sub Grid Constrained Area:	BIG EDDY/MAUPIN 230				
PTDF #:	40709	40111			

Flowgate	Source	Sink	% Impact	MW Impact	Result
CROSS CASCADES NORTH E>W	-0.1607	-0.1545	-0.6%	0.0	Potential LTF
CROSS CASCADES SOUTH E>W	0.1024	0.1428	-4.0%	0.0	Potential LTF
NORTH OF HANFORD N>S	-0.6171	-0.6425	2.5%	2.5	Potential LTF
RAVER-PAUL N>S	-0.1035	-0.1000	-0.3%	0.0	Potential LTF
SOUTH OF ALLSTON N>S	-0.1659	-0.1606	-0.5%	0.0	Potential LTF
NORTH OF PEARL S>N	0.0846	0.1012	-1.7%	0.0	Potential LTF
WEST OF JOHN DAY E>W	-0.2866	-0.5245	23.8%	23.8	Potential LTF
WEST OF SLATT E>W	-0.1853	-0.1823	-0.3%	0.0	Potential LTF
WEST OF LOWER MONUMENTAL E>W	-0.0597	-0.0640	0.4%	0.4	Potential LTF
SOUTH OF CUSTER N>S	-0.0021	-0.0028	0.1%	0.1	Potential LTF
NORTH OF ECHO LAKE S>N	0.0439	0.0453	-0.1%	0.0	Potential LTF
WEST OF MCNARY E>W	-0.1475	-0.1528	0.5%	0.5	Potential LTF
WEST OF HATWAI E>W	0.0503	0.0439	0.6%	0.6	Potential LTF
NORTH OF GRIZZLY N>S	0.1097	0.0557	5.4%	5.4	Potential LTF

[13] BPA PTDF Calculator Effective 10/18/2023.

		Zone	kV	Owner Name
Evaluated Source:	SLATT	Lower Columbia Basin	500	Bonneville Power Admin
Evaluated Sink:	BIGEDDY	Lower Columbia Basin	500	Bonneville Power Admin
Request MW:	100			

Posted 10/18/23

Sub Grid Constrained Area:		
PTDF #:	40989	40111

Flowgate	Source	Sink	% Impact	MW Impact	Result
CROSS CASCADES NORTH E>W	-0.1315	-0.1545	2.3%	2.3	Potential LTF
CROSS CASCADES SOUTH E>W	0.1139	0.1428	-2.9%	0.0	Potential LTF
NORTH OF HANFORD N>S	-0.6623	-0.6425	-2.0%	0.0	Potential LTF
RAVER-PAUL N>S	-0.0835	-0.1000	1.7%	1.7	Potential LTF
SOUTH OF ALLSTON N>S	-0.1350	-0.1606	2.6%	2.6	Potential LTF
NORTH OF PEARL S>N	0.0922	0.1012	-0.9%	0.0	Potential LTF
WEST OF JOHN DAY E>W	0.1935	-0.5245	71.8%	71.8	Potential LTF
WEST OF SLATT E>W	0.5072	-0.1823	69.0%	69.0	Potential LTF
WEST OF LOWER MONUMENTAL E>W	-0.0749	-0.0640	-1.1%	0.0	Potential LTF
SOUTH OF CUSTER N>S	-0.0009	-0.0028	0.2%	0.2	Potential LTF
NORTH OF ECHO LAKE S>N	0.0431	0.0453	-0.2%	0.0	Potential LTF
WEST OF MCNARY E>W	-0.1939	-0.1528	-4.1%	0.0	Potential LTF
WEST OF HATWAI E>W	0.0410	0.0439	-0.3%	0.0	Potential LTF
NORTH OF GRIZZLY N>S	0.0586	0.0557	0.3%	0.3	Potential LTF

		Zone	kV	Owner Name
Evaluated Source:	VANTAGE	Central Washington	230	Bonneville Power Admin
Evaluated Sink:	BIGEDDY	Lower Columbia Basin	500	Bonneville Power Admin
Request MW:	100			

Posted 10/18/23

Sub Grid Constrained Area:		
PTDF #:	41111	40111

Flowgate	Source	Sink	% Impact	MW Impact	Result
CROSS CASCADES NORTH E>W	-0.0364	-0.1545	11.8%	11.8	Potential LTF
CROSS CASCADES SOUTH E>W	0.0327	0.1428	-11.0%	0.0	Potential LTF
NORTH OF HANFORD N>S	0.0025	-0.6425	64.5%	64.5	Potential LTF
RAVER-PAUL N>S	-0.0195	-0.1000	8.1%	8.1	Potential LTF
SOUTH OF ALLSTON N>S	-0.0332	-0.1606	12.7%	12.7	Study for CFS
NORTH OF PEARL S>N	0.0150	0.1012	-8.6%	0.0	Potential LTF
WEST OF JOHN DAY E>W	-0.0033	-0.5245	52.1%	52.1	Potential LTF
WEST OF SLATT E>W	0.0085	-0.1823	19.1%	19.1	Potential LTF
WEST OF LOWER MONUMENTAL E>W	-0.0456	-0.0640	1.8%	1.8	Potential LTF
SOUTH OF CUSTER N>S	-0.0054	-0.0028	-0.3%	0.0	Potential LTF
NORTH OF ECHO LAKE S>N	0.0310	0.0453	-1.4%	0.0	Potential LTF
WEST OF MCNARY E>W	0.0218	-0.1528	17.5%	17.5	Potential LTF
WEST OF HATWAI E>W	0.0189	0.0439	-2.5%	0.0	Potential LTF
NORTH OF GRIZZLY N>S	0.0069	0.0557	-4.9%	0.0	Potential LTF

Attachment 10. Tribal Business New Article, November 1, 2024

TRIBAL BUSINESS NEWS

Oregon tribe's $857M power line upgrade could unlock renewable energy future

Members of the Confederated Tribes of Warm Springs and reps of Portland General Electric meet at the partners' shared hydroelectric plant, Round Butte Dam. Round Butte serves as one end of a 230 kv line set for an upgrade thanks in part to a $250 million contribution from the tribe. (Photo by Portland General Electric)

BY CHEZ OXENDINE |

NOVEMBER 1, 2024

Sometimes the biggest barrier to renewable energy isn't financing or building the project — it's getting the power where it needs to go.

That's precisely the challenge facing the Confederated Tribes of Warm Springs, whose 644,000 acres of prime renewable energy territory in central Oregon is hamstrung by a congested transmission line that severely limits their ability to move power off the reservation.

That infrastructure challenge has stalled roughly half a dozen potential renewable energy projects, according to Cathy Ehli, general manager for the tribes' Warm Springs Power and Water utility enterprise. Without improved transmission capacity, those projects may never materialize.

"We could be waiting years in an interconnection queue, so the tribe has been unable to develop its renewable energy potential," Ehli told *Tribal Business News*. "You couldn't take the energy anywhere if we built it."

The tribes' challenge reflects a broader problem. According to a report by Washington, D.C.-based power consultancy Grid Strategies LLC, transmission congestion cost the U.S. $13.4 billion in 2021, driven by inadequate capacity to support renewable energy growth, extreme weather events, and growing electricity demand.

To address the bottleneck, the Confederated Tribes have partnered with Portland General Electric (PGE) to upgrade the 230 kilovolt line between the Oregon cities of Bethel and Round Butte. The $857 million project will nearly double the line's capacity to 500 kilovolts and could open new possibilities for tribal energy development. As an added benefit, new broadband fiber lines installed as part of the upgrade will serve as a backbone for new internet connectivity projects along the transmission corridor.

The partnership builds on decades of collaboration between the tribes and PGE. They have co-owned and jointly operated the Pelton Round Butte hydropower project in central Oregon for several decades, generating enough emissions-free energy to power more than 150,000 homes while working to restore salmon and steelhead runs in the Deschutes River basin.

For the new transmission line project the tribes will commit $250 million to the upgrade through a grant received from the Department of Energy's Grid Resilience Innovation Partners program, gaining partial ownership of the line in the process.

Ehli said the upgrade could "unlock" vast economic potential for the tribe's renewable energy prospects, giving them a way to send generated energy out of the reservation and into rapidly growing power markets.

"When we found out we had gotten the grant to do this, I'm not sure my feet touched the ground for a day or two," Ehli said. "It's a fantastic project, but the bigger picture to me was the future stability it could create for the tribe economically, which was sort of the icing on the cake."

In a statement provided to *Tribal Business News*, Tribal Council Chairman Jonathan Smith said the transmission line upgrade was a way to exercise tribal sovereignty.

"This Bethel-Round Butte Transmission Line upgrade allows us to continue sustaining our land through restoration work and our people through jobs, education and generational wealth," Smith said. "We look forward to growing the role of our Tribes in shaping Oregon's energy future."

The project recently kicked off with a meeting between the tribes and PGE, marking the start of an expected eight-year development timeline.

The tribes also allocated $10 million of the grant for a "community benefits program" to develop educational programs for students and an apprenticeship program for aspiring electricians. With two years of planning ahead, the tribes aim to have workforce development and training opportunities ready when construction begins.

The community benefits program is quite extensive in what it anticipates the tribe's needs will be, Ehli said. "We're going to be ready not just for the construction jobs the project brings, but for educational and other workforce opportunities."

Ehli said the transmission line upgrade, in both opening up the path for renewable development and giving the tribe partial ownership of the line, could be a model for other tribes hoping to break similar barriers.

"While this is a really exciting project, the potential is so much bigger," Ehli said. "We're excited for that, because it really begins what can be a snowball of economic development in a variety of different ways, and I think other tribes could do this too."

Brian Edwards contributed reporting to this story.

About The Author

Chez Oxendine

Staff Writer

Chez Oxendine (Lumbee-Cheraw) is a staff writer for Tribal Business News. Based in Oklahoma, he focuses on broadband, Indigenous entrepreneurs, and federal policy. His journalism has been featured in Native News Online, Fort Gibson Times, Muskogee Phoenix, Baconian Magazine, and Oklahoma Magazine, among others.
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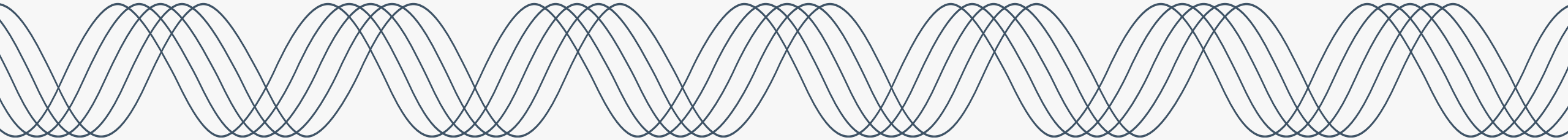
Attachment 11. PGE CEP-IRP Roundtable 24-6 Public Presentation

PGE CEP & IRP Roundtable 24-6

October 2nd 2024



October 2nd, 2024 – Agenda

9:00 – 9:05	Welcome | Meeting Logistics
9:05 – 9:35	RFP Proxy
9:35 – 10:10	DER Update
10:10 – 10:30	Transmission | Step 1: Existing Capacity
10:30 – 11:05	Transmission | Step 2: Future Capacity
11:05 – 11:25	Modified Price Forecast
11:25 – 11:30	Closing Remarks | Next Steps

Meeting Details

1

Electronic version of presentation

https://portlandgeneral.com/about/who-we-are/resource-planning/combined-cep-and-irp/combined-cep-irp-public-meetings

2

Zoom meeting details

- Join Zoom Meeting https://us06web.zoom.us/j/9291862450?pwd=xVXQI4jljt7FdetDzWD0G35FFvayF8.1&omn=84372774388
- Meeting ID: 929 186 2459
- Passcode: 108198

3

Participation

- Please rename yourself indicating the organization you represent if applicable.
- Use the raise the hand feature to let us know you have a question
- Unmute with microphone icon or *6

Meeting Logistics

Focus on Learning & Understanding

- There will be no chat feature during the meeting to streamline taking feedback
- Team members will take clarifying questions during the presentation, substantive questions will be saved for the end (time permitting)
- Attendees are encouraged to ‘raise’ their hand to ask questions

Follow Up

If we don’t have time to cover all questions, we will rely on the CEP/IRP feedback form

RFP Proxy

Rob Campbell, PGE

Purpose of RFP Proxy

The RFP (Request for Proposal) proxy is a placeholder in PGE's modeled baseline portfolio for resources that are expected to be acquired through the ongoing RFP.

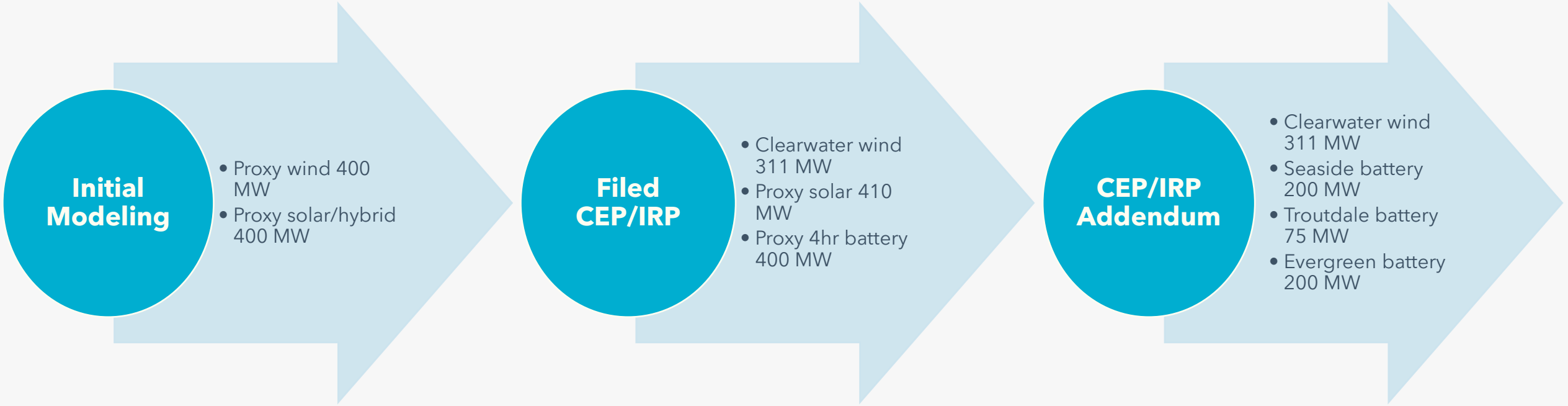
Because negotiations for project acquisition are ongoing, the actual resources that will become part of PGE's portfolio are unknown.

Based on the resources on the RFP final shortlist, the RFP proxy is an informed estimate about the quantity of resources that will be acquired.

The RFP proxy represents the energy and capacity benefits contributed to PGE's portfolio by the expected resources so they can be accounted for in calculation of energy and capacity needs.

Proxy resources in the RFP proxy are replaced by the characteristics of actual projects when certainty of acquisition is achieved.

RFP Proxy in the 2023 CEP/IRP



The RFP proxy was updated throughout the 2023 CEP/IRP process, replacing the proxy with details about the actual projects as new information became available.

The evolution in resource mix of the RFP proxy in the 2023 CEP/IRP illustrates the uncertainty inherent in commercial negotiations for resource acquisition.

Updating of the RFP proxy can lead to changes in estimates of energy need and resource ELCCs, the calculation of which are dependent on resource mix.

RFP Proxy in the IRP Update

The 2023 RFP final shortlist contains four projects:

- 250 MW solar & 250 MW battery
- 41 MW solar
- 400 MW battery
- 125 MW solar and 125 MW battery

To represent the energy and capacity provided by the projects on the final shortlist, the current RFP proxy consists of:

- Proxy solar/battery hybrid 375 MW
- Proxy standalone solar 41 MW
- Proxy standalone battery 400 MW

Resources in the RFP proxy will be replaced with details about actual projects as contracts are signed.

If commercial negotiations proceed quickly, we may replace the whole RFP proxy with actual projects in our models for the IRP Update.

However, if necessary, based on timing of execution, some or all projects will be represented by the RFP proxy in modeling.

DER Update

Seth Wiggins, PGE

Fred Schaefer, Cadeo

PGE's 2023 CEP/IRP uses two forecasts of Distributed Energy Resources (DERs)

Both come from PGE's Distribution System Planning team

1. Cost-effective DERs: Quantities of DERs that are projected to be added (and that PGE should plan for)
   - *Given the current economics, what will customers procure?*
2. Additional DERs: Quantities of DERs that could be acquired (that PGE should evaluate)
   - *Given the current economics of supply-side resources included in portfolio modeling would it make sense for PGE to procure more?*

The 2023 CEP/IRP used DER forecasts from 2022 DSP II (created in March 2022) and were updated for the 2023 CEP/IRP Addendum (created June 2023)

Today Cadeo will describe their updated forecast.

Updates for August 2024 Forecast

2024 Q3 Forecast Vintage Updates

Current DER "stock" from PGE Systems of Record

- Solar PV and Storage
- Transport Electrification (TE): DMV data mapped to PGE service points

Adoption Curves

- TE: expected impacts of Advanced Clean Cars II and Advanced Clean Truck mandates, known fleet electrification plans
- Building Electrification (BE): expected impact of Inflation Reduction Act legislation
- Solar PV: incorporate available federal and local policy support, future panel price trends

Hourly Load Impact

- BE: Residential 8760 shapes from ResStock 2024.2 Release

Program Costs

- Refreshed selected PGE customer program costs

Avoided Costs

- Generation and distribution capacity from UM 1893
- Flexibility capacity are from 2023 IRP (using average of values for years 2026-2030)

DER Forecasting Approach

AdopDER is our DER Forecasting Software

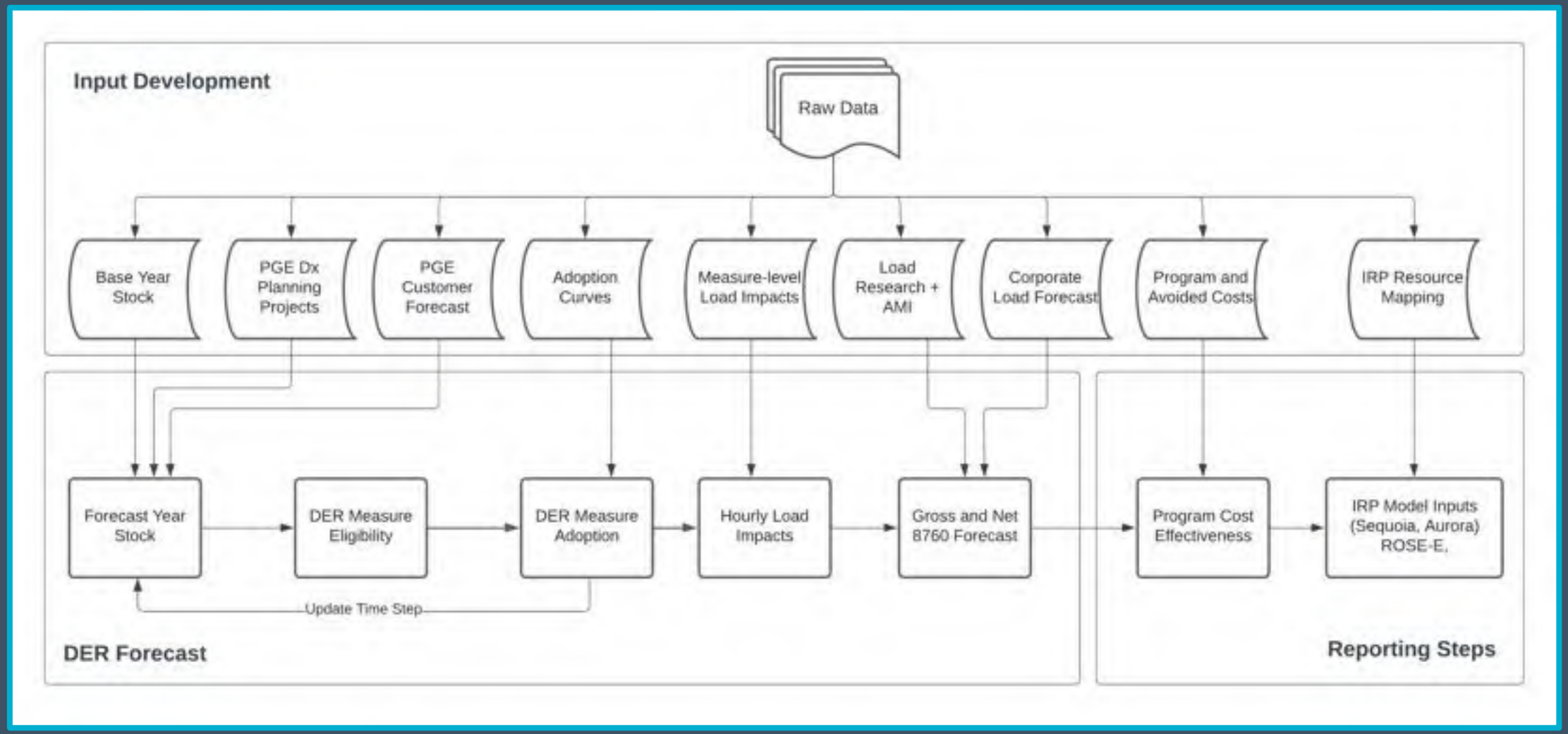
Consistent forecasting process from 2021 to present

- Distribution Resource Planning group owns process at PGE
- Service-territory DER potential estimate
- Feeder-level load forecast, net of DER adoption (2022)
- Service-point level load forecast for Dx Planning (2024)

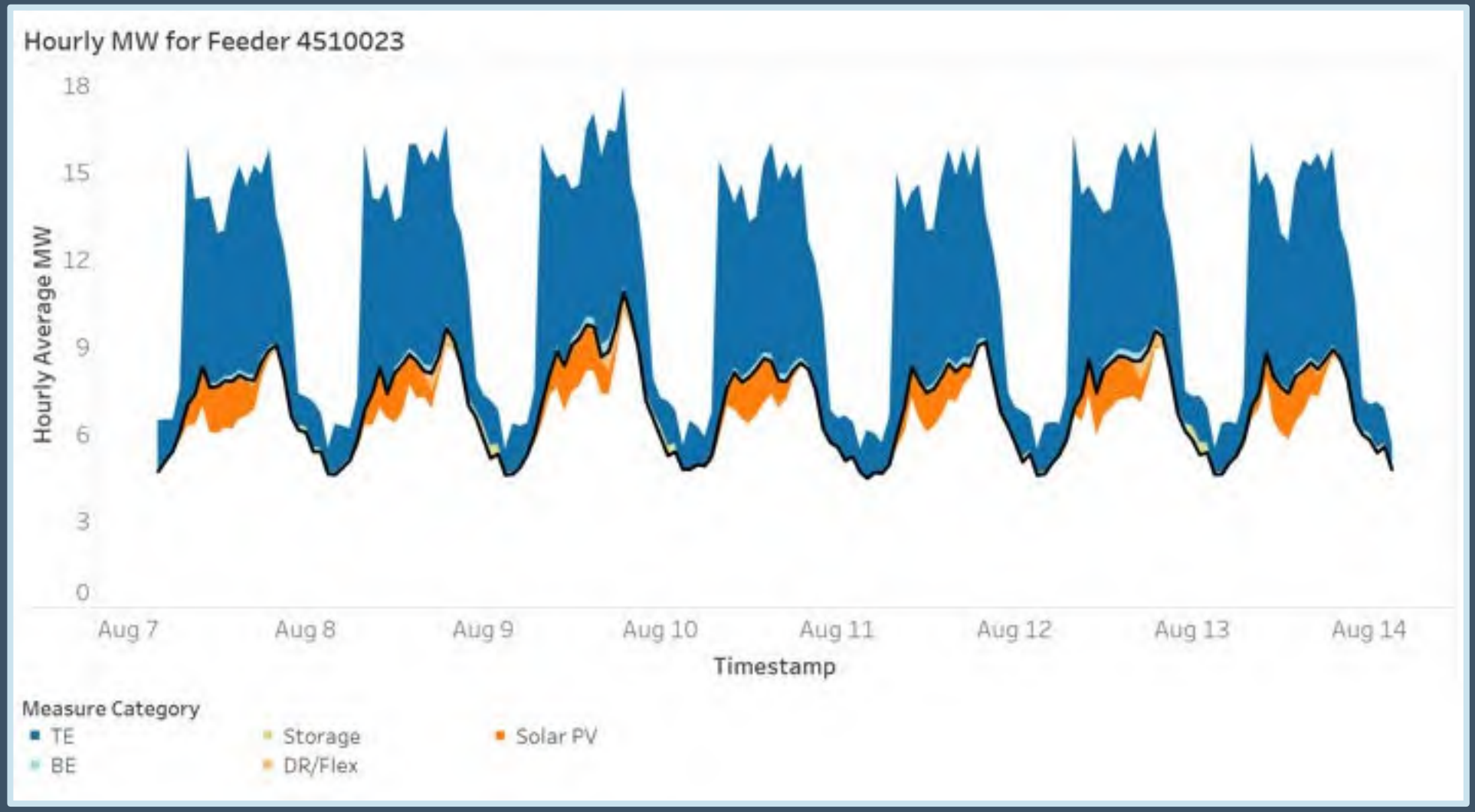
Broad definition of DERs:

BTM Solar PV	Building Electrification	DLC
BTM Storage	Electric Vehicles	Time-of-Use
Microgrids	EVSE	Curtailment

AdopDER Forecasting Framework



Illustrative 8760 Forecast from AdopDER



We consider multiple forecast scenarios, each with many assumptions

Reference Case

- "Most likely" outcome.
- Based on known policies, adoption trends, and/or moderate technology costs.

Low Adoption

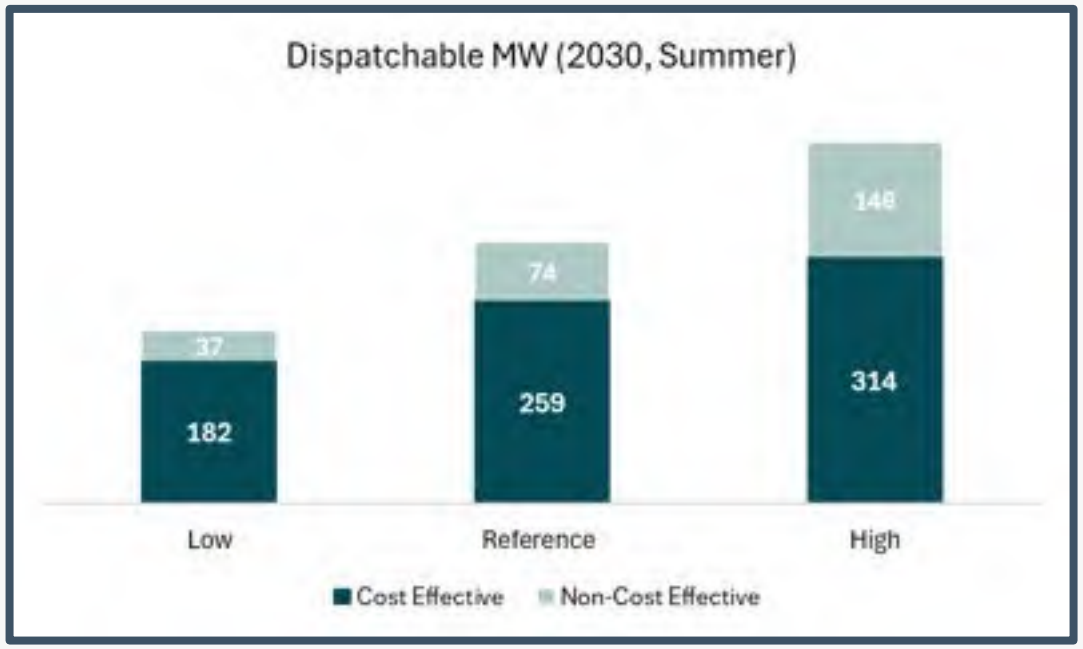
- A lower bound alternative scenario.
- Based on less aggressive policies, adoption trends, and/or higher technology costs.

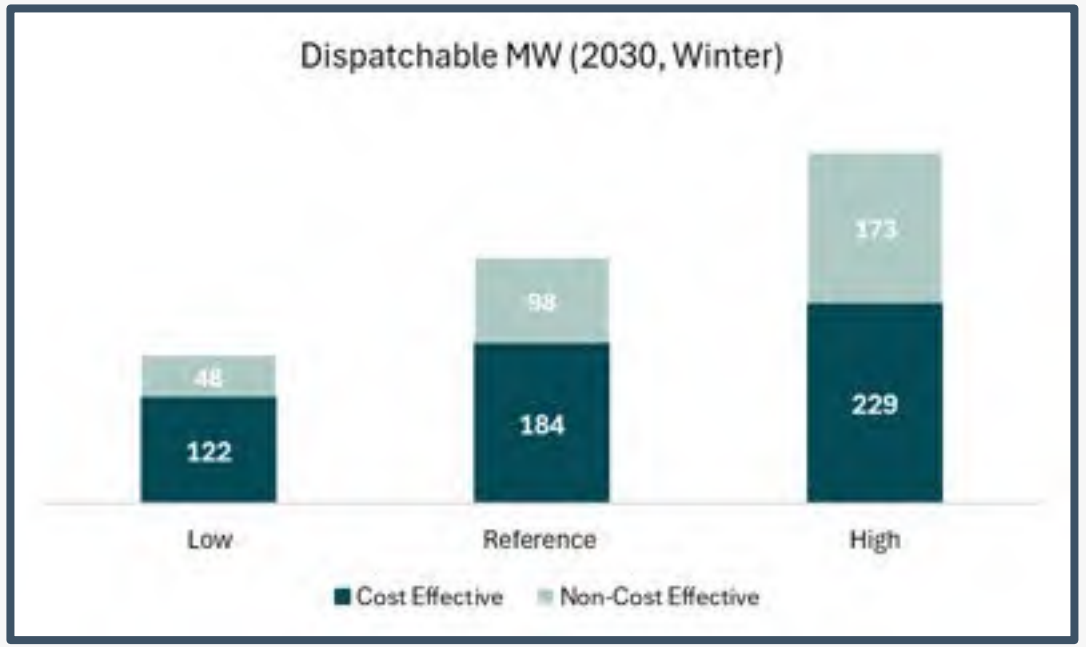
High Adoption

- An upper bound alternative scenario.
- Based on more aggressive policies, adoption trends, and/or lower technology costs.

High-level Forecast Results

Dispatchable MW by Scenario

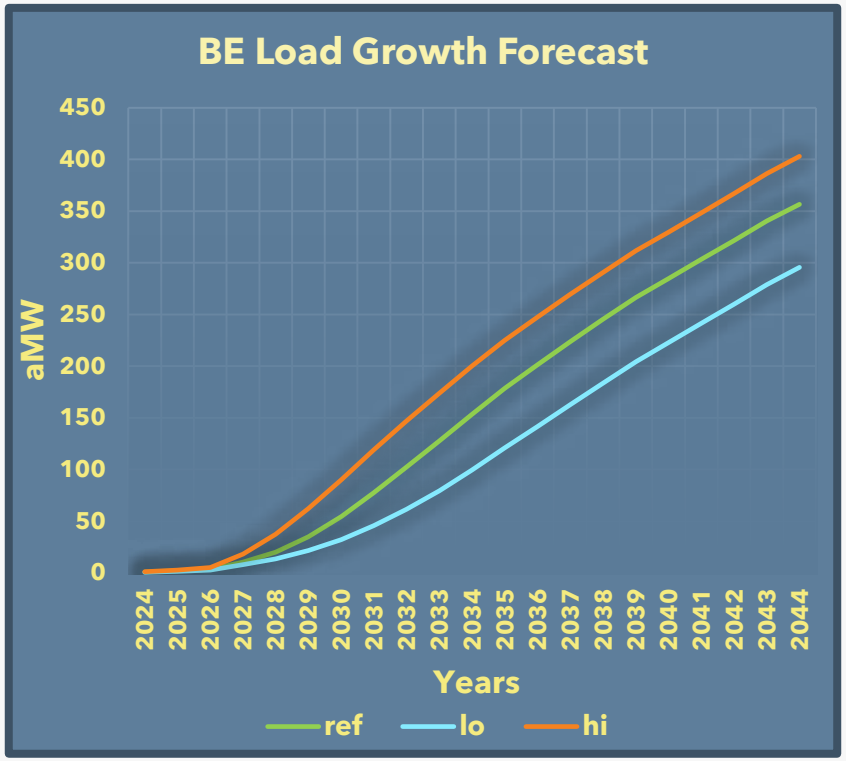


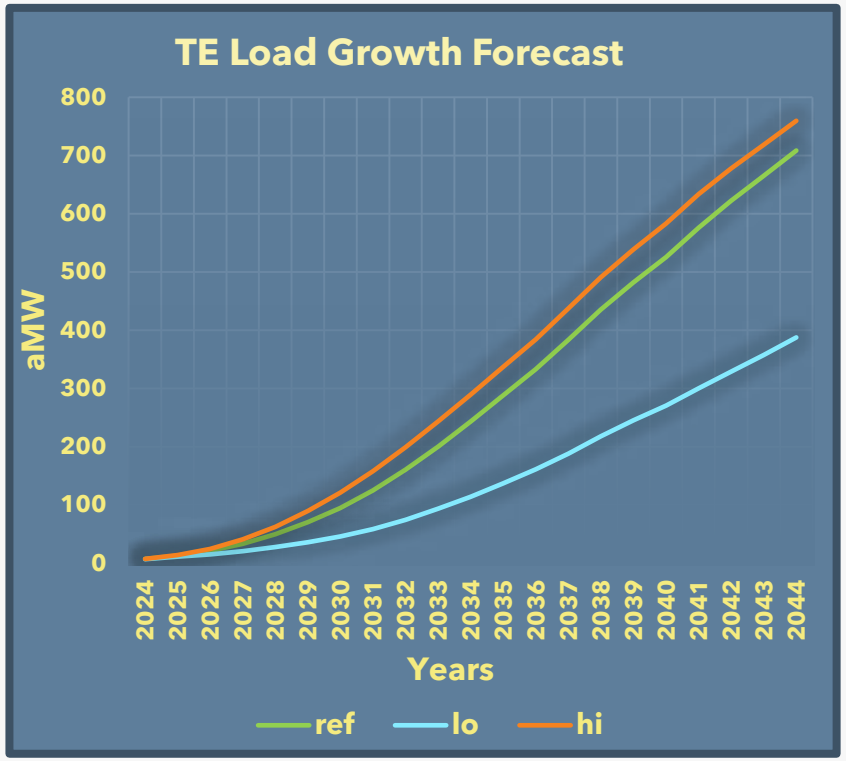


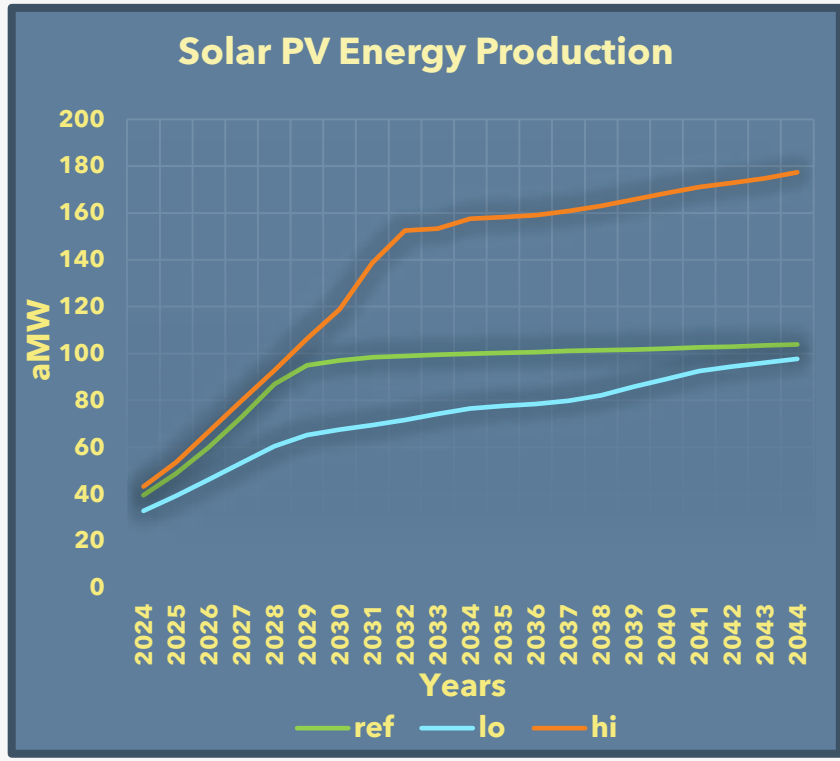
Includes current and possible PGE customer programs: curtailment, DLC (Thermostat, WH, and EVSE), flexible loads, utility-controlled storage, building electrification

DLC: Direct Load Control
WH: Water Heater
EVSE: Electric Vehicle Supply Equipment

Annual Load Impacts by Scenario



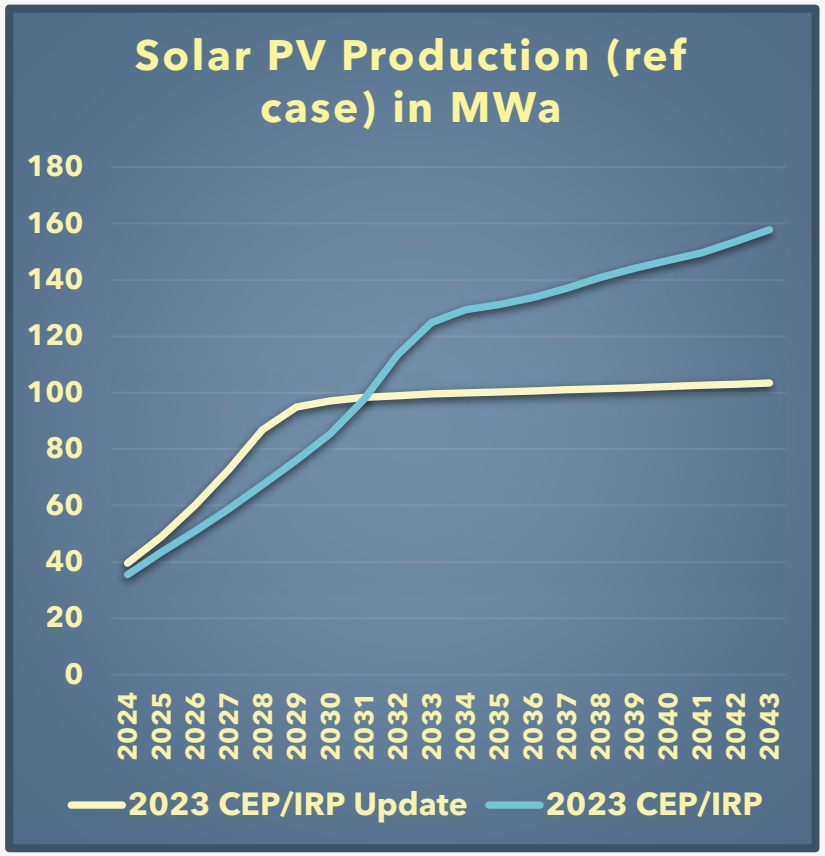


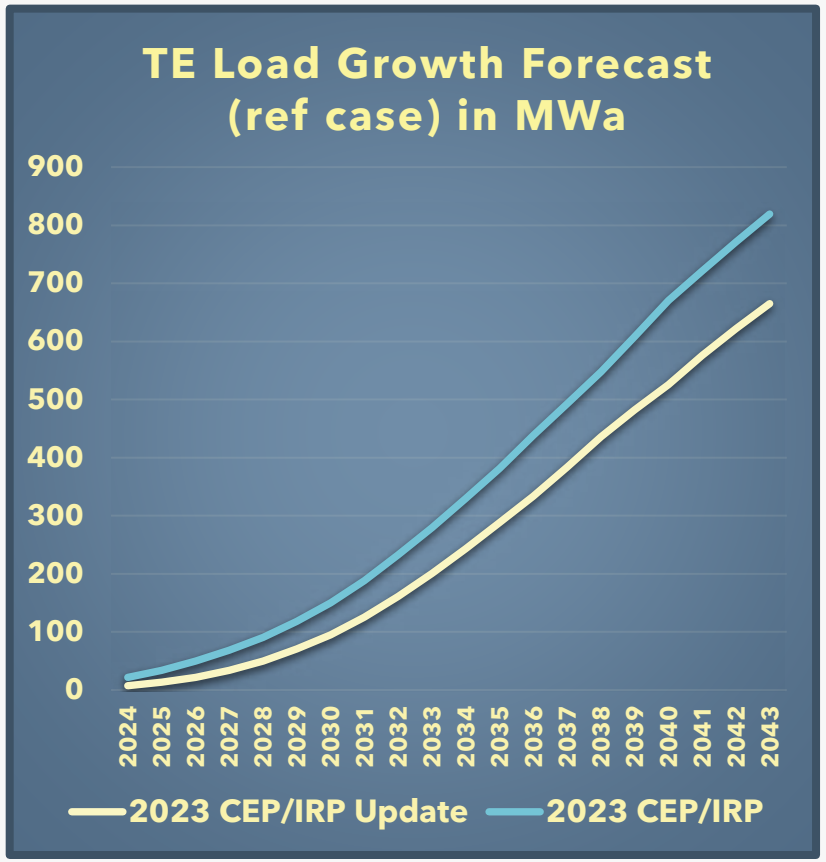


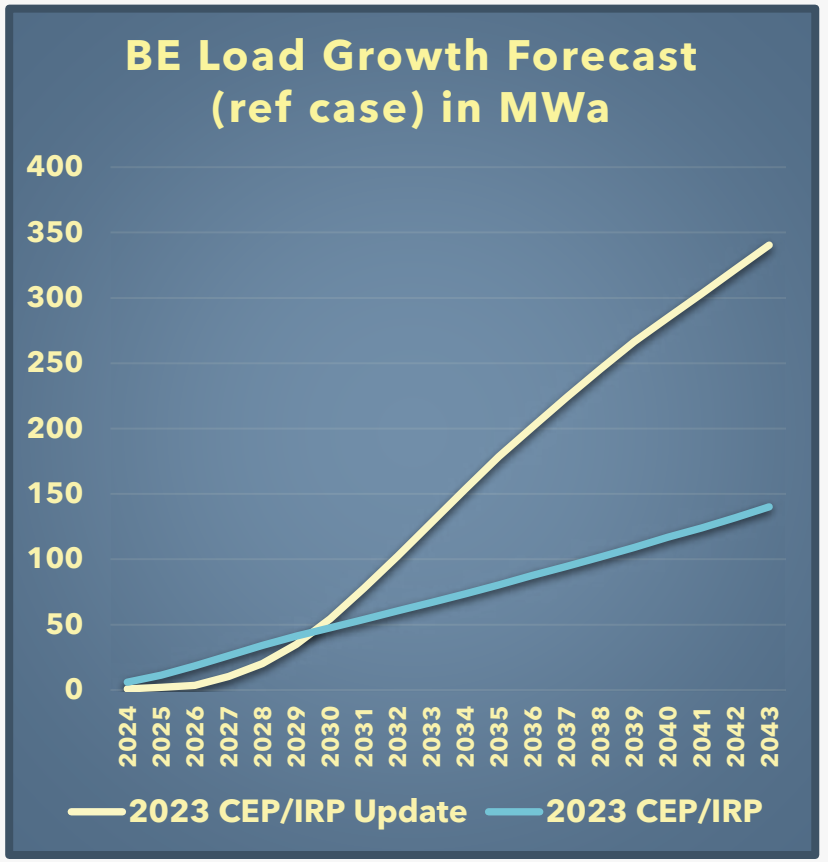
These annual load impacts modify the annual load forecast that IRP models use.

BE: Building Electrification
TE: Transportation Electrification

Comparison of 'ref' Forecasts Between 2023 CEP/IRP and 2023 CEP/IRP Update

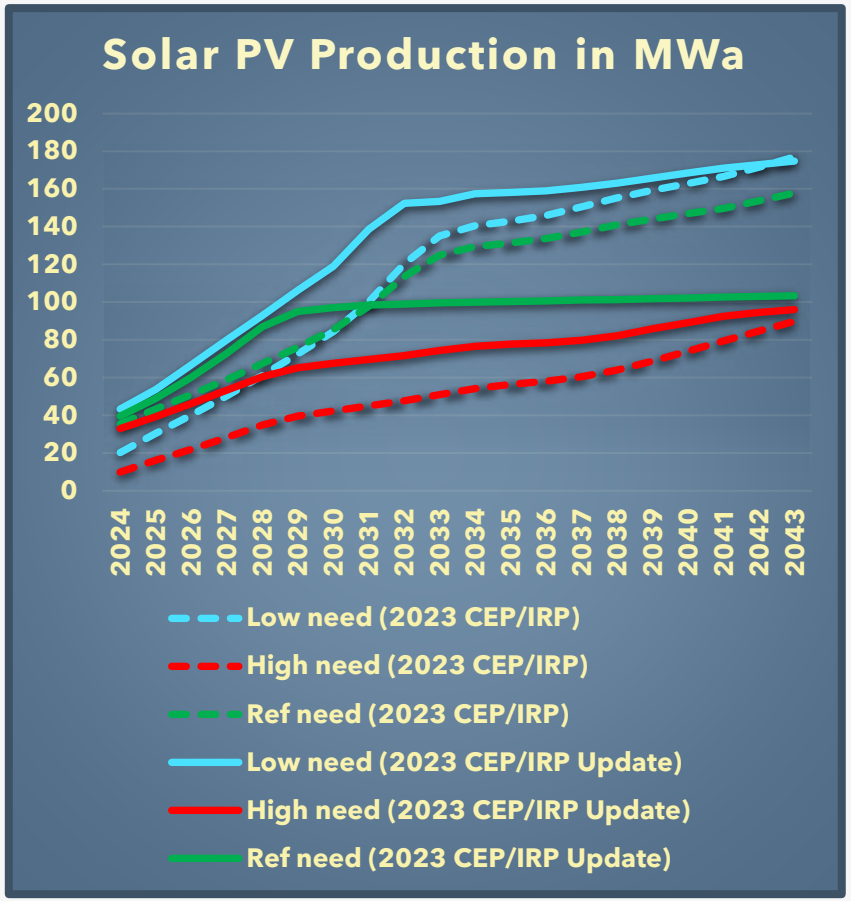


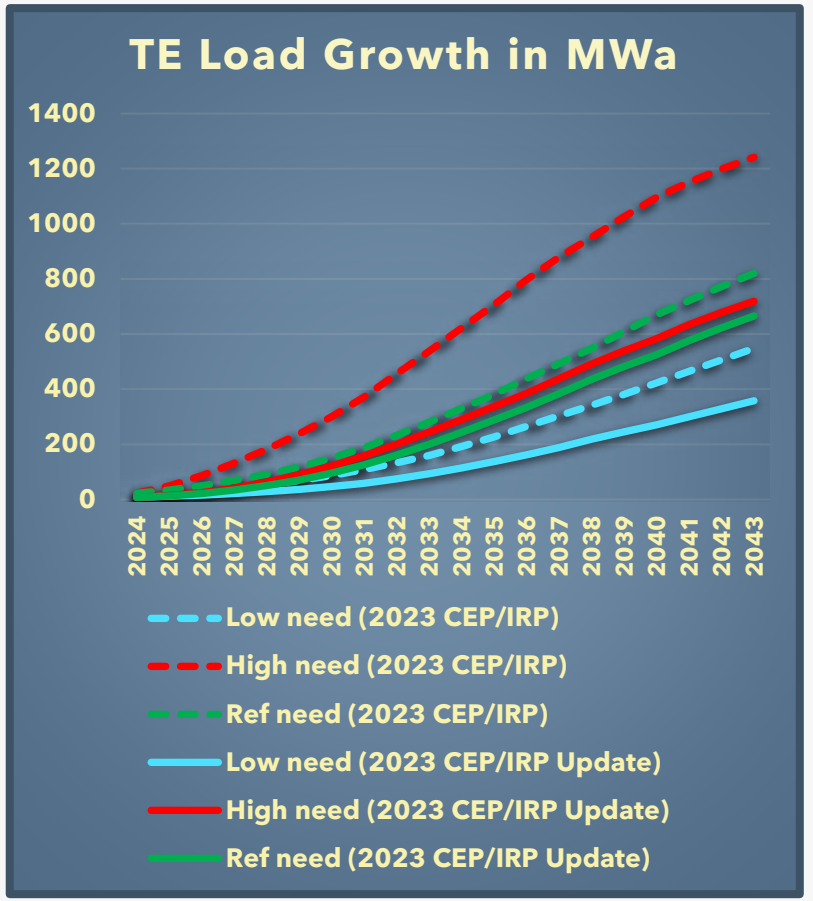


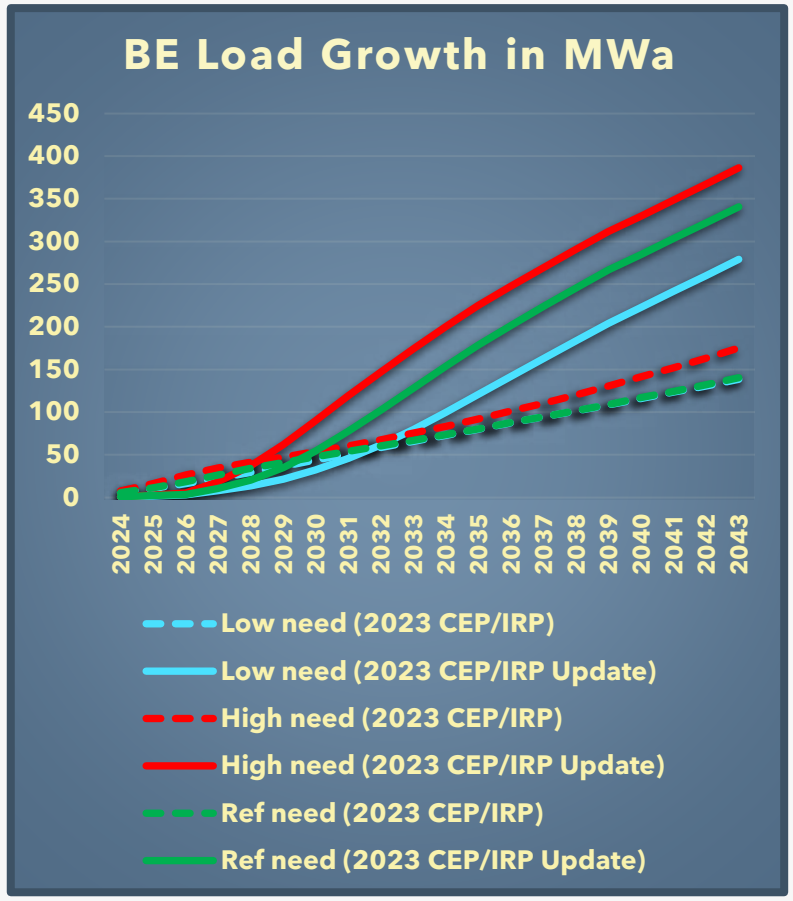


BE: building electrification
TE: transportation electrification

Comparison of Forecasts Between 2023 CEP/IRP and 2023 CEP/IRP Update







BE: building electrification
TE: transportation electrification

Transmission | Step 1 : Existing Capacity

Laura Green, PGE

Seth Wiggins, PGE

2023 CEP/IRP Update Transmission Modeling

PGE's geography necessitates an analysis with three components:

1. A characterization of the existing transmission system

- How much transmission capacity is available to PGE today?

2. A characterization of the future transmission system

- How much transmission capacity will be available to PGE when expected upgrades are made?

3. A description of actions PGE can take to increase transmission capacity (September 2024 Roundtable)

- What can PGE do to bring more transmission capacity?

2023 CEP/IRP Update Transmission Modeling

PGE's geography necessitated an analysis requiring three components:

A characterization of the existing transmission system [Discussed here]

- How much transmission capacity is available to PGE today?

In the 2023 CEP/IRP, PGE extrapolated from Transmission Service Requests (TSRs) in BPA's previous four TSR Study and Expansion Process (TSEPs) to estimate this transmission capacity in each resource zone

We are following that method and presenting updated results here

Table 129 from the 2023 CEP/IRP:

Resource Zone	LTF	CF	Total
Christmas Valley	490	510	1000
Gorge	190	388	578
McMinnville	10	0	10
Montana	0	0	0
Offshore	0	80	80
SE Washington	0	150	150
Total	690	1128	1818

July Roundtable:

IRP Zone	Long Term Firm	Conditional Firm	Total
Christmas Valley	3	*	
Gorge	875	*	
McMinnville	80	*	
Montana	250	*	
Offshore	80	*	
Southeast Washington	0	*	
Wasco	76	*	
Total	**1394**	**1360**	**2754**

*NewPoint TSRs are under study and masked. Therefore, IRP Zones are not available

Updated Existing Transmission Forecast

IRP Zone	Long Term Firm	Conditional Firm	Total
Christmas Valley	~~3~~ 201	~~*~~ 466	667
Gorge	~~875~~ 55	~~*~~ 129	184
McMinnville	~~80~~ 45	~~*~~ 105	150
Montana	~~250~~ 96	~~*~~ 224	320
Offshore	~~80~~ 201	~~*~~ 467	668
Southeast Washington	~~0~~ 31	~~*~~ 73	104
Wasco	~~76~~ 124	~~*~~ 289	413
Total	**~~1394~~ 753**	**~~1360~~ 1753**	**~~2754~~ 2506**

*NewPoint TSRs are under study and masked. Therefore, IRP Zones are not available

Methodological Change for Existing Transmission Forecast

July Methodology	Update Methodology
• Queried TSRs in OASIS with a status of Received, Study and Confirm. • Request type: Originals and Redirects. • Start date: 8/20/2022 (close of the 2023 Cluster Study window) – 8/15/2024 close of the 2025 Cluster Study window. • LTF PTP TSRs in a study status and requesting NewPoint with a POD of BPAT.PGE (resource sink zone information not available)	• Analyzed BPA's LTF queue data from 2016-2023. • 2016-2023 LTF Queue: Used the 2019-2023 Cluster Study data[1] to determine resource zones (POR/POD) and MW amounts. • 2019-2023 TSEPs/EG: Used Evolving Grid 2019-2023 Cluster Study data to determine LTF and CF amounts. CF 70% awarded; LTF 30% awarded.

LTF: long term firm
CF: conditional firm
OASIS: open access same time information system
POD: point of delivery
PTP: point to point
TSR: transmission service request

[1]From BPA's Evolving Grid Presentation, May 16, 2024

Transmission | Step 2: Future Capacity

Laura Green, PGE

Seth Wiggins, PGE

2023 CEP/IRP Update Transmission Modeling

PGE's geography necessitates an analysis with three components:

1. A characterization of the existing transmission system

- How much transmission capacity is available to PGE today?

2. A characterization of the future transmission system

- How much transmission capacity will be available to PGE when expected upgrades are made?

3. A description of actions PGE can take in increase transmission capacity

- What can PGE do to bring more transmission capacity?

2023 CEP/IRP Update Transmission Modeling

PGE's geography necessitated an analysis requiring three components:

A characterization of the future transmission system

- How much transmission capacity will be available to PGE when expected upgrades are made?

In the 2023 CEP/IRP, once transmission capacity inventories were exhausted ROSE-E only had access to transmission expansion options (e.g., NV WY, SOA resources)

This assumed that no additional transmission capacity would become available

No Comparable Input in 2023 CEP/IRP

Forecasted Impact of Evolving Grid

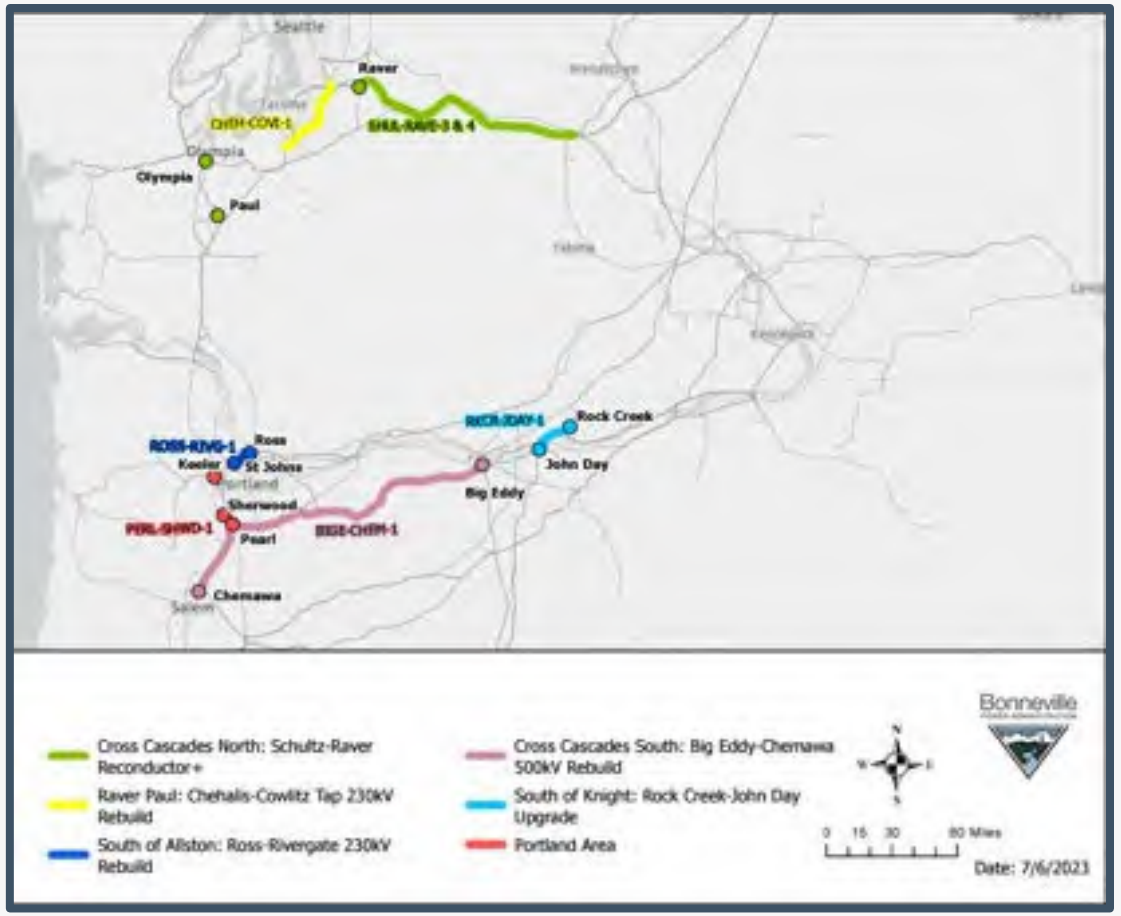
In July 2023, BPA announced their intent to construct a collection of transmission infrastructure referred to as BPA's 'Evolving Grid' projects. Together these projects were forecasted to cost over $2 Billion.

BPA has hosted three workshops regarding these infrastructure plans and the next update is anticipated in Q4 2024.

PGE's 2023 CEP/IRP Update will assume that these projects announced by BPA are successfully constructed and allocated as network assets due to their status as 'Regionally Needed Projects.'

The current list of projects include:

- Schultz-Raver Reconducter
- Bid Eddy-Chemawa 500kV Rebuild
- Covington-Chehalis 230kV Rebuild
- Ross-Rivergate 230kV Rebuild
- Rock Creek-John Day
- Pearl-Sherwood-McLoughlin



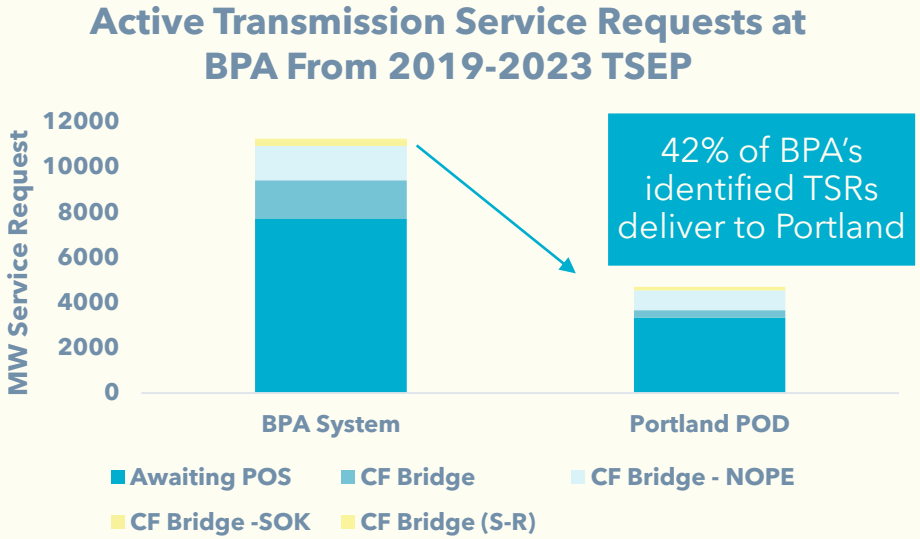
Forecasted Impact of Evolving Grid Cont.

In April 2023, BPA communicated that upon completion of all Evolving Grid projects, 4260 MW of additional transmission service will be enabled.

Using publicly available information, PGE estimates that 42% (1779 MW) of that enabled service will allow for firm transmission service delivered to the Portland area.

Projects are currently forecasted to be complete in 2032. Upon completion, 1753 MW conditional firm bridge transmission will convert to long term firm service. An additional 26 MW of long-term firm transmission service is forecasted by PGE to be marketed upon completion of identified Evolving Grid Projects.

PGE will monitor ongoing Evolving Grid updates to consider incorporating updated information.



As presented at BPA's May 2024 Evolving Grid Update

Incremental Transmission Service as of Jan 2033

	Incremental Transmission Service as of Jan 2033		
IRP Zone	Long Term Firm	Conditional Firm	Total
Christmas Valley	7		7
Gorge	2		2
McMinnville	2		2
Montana	3		3
Offshore	7		7
Southeast Washington	1		1
Wasco	4		4
Total	**26**		**26**

Conditional-firm upgrades

IRP Zone	Conditional Firm in 2025
Christmas Valley	466
Gorge	129
McMinnville	105
Montana	224
Offshore	467
Southeast Washington	73
Wasco	289
Total	**1753**

IRP Zone	Long Term Firm in 2033
Christmas Valley	466
Gorge	129
McMinnville	105
Montana	224
Offshore	467
Southeast Washington	73
Wasco	289
Total	**1753**

Total 2033 Transmission Capacity

	Identified Transmission Service As of Jan 2033		
IRP Zone	Long Term Firm	Conditional Firm	Total
Christmas Valley	674	-	674
Gorge	186	-	186
McMinnville	152	-	152
Montana	323	-	323
Offshore	675	-	675
Southeast Washington	105	-	105
Wasco	417	-	417
Total	**2532**	-	**2532**

Updated Price Forecasts

New Methodology for 2023 CEP/IRP Update

Chris White, PGE

2023 CEP/IRP Price Forecast

PGE benefitted from extensive discussions on our electricity price forecasts with stakeholders in several CEP/IRP Roundtables[1]. These discussions identified the following risk drivers to be considered in the IRP forecasts:

- **Gas prices** and hydro conditions
- Cost of compliance with potential carbon policy/policies
- Uncertainty in net load
- Scarcity of committed dispatchable resources

***Updated between 2023 CEP/IRP and 2023 CEP/IRP Update**
**Unchanged between 2023 CEP/IRP and 2023 CEP/IRP Update

1 February 2021, May 2021, November 2021, April 2022

2023 CEP/IRP Price Forecast

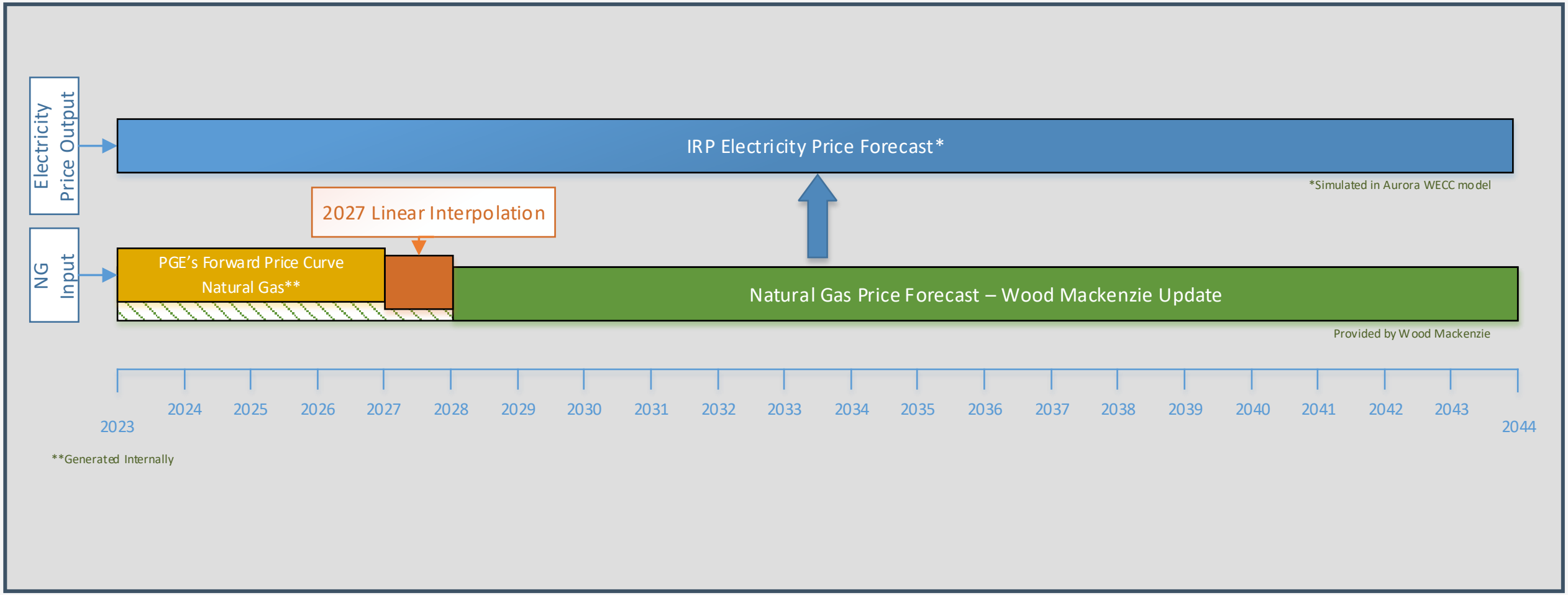
PGE relies on the expertise of a power research consultancy, Wood Mackenzie (WM):

- To project the Western Electricity Coordinating Council (WECC) resource buildout and development, and its impact on electricity prices.
- To incorporate WM's natural gas price forecasts into its long-term **electricity price** forecasts.

2023 CEP/IRP: Uses WM's long-term reference gas price forecast from **June 2022**

2023 CEP/IRP Update: Uses WM's long-term reference gas price forecast from **December 2023**

2023 CEP/IRP Price Forecast



2023 CEP/IRP UPDATED Price Forecast

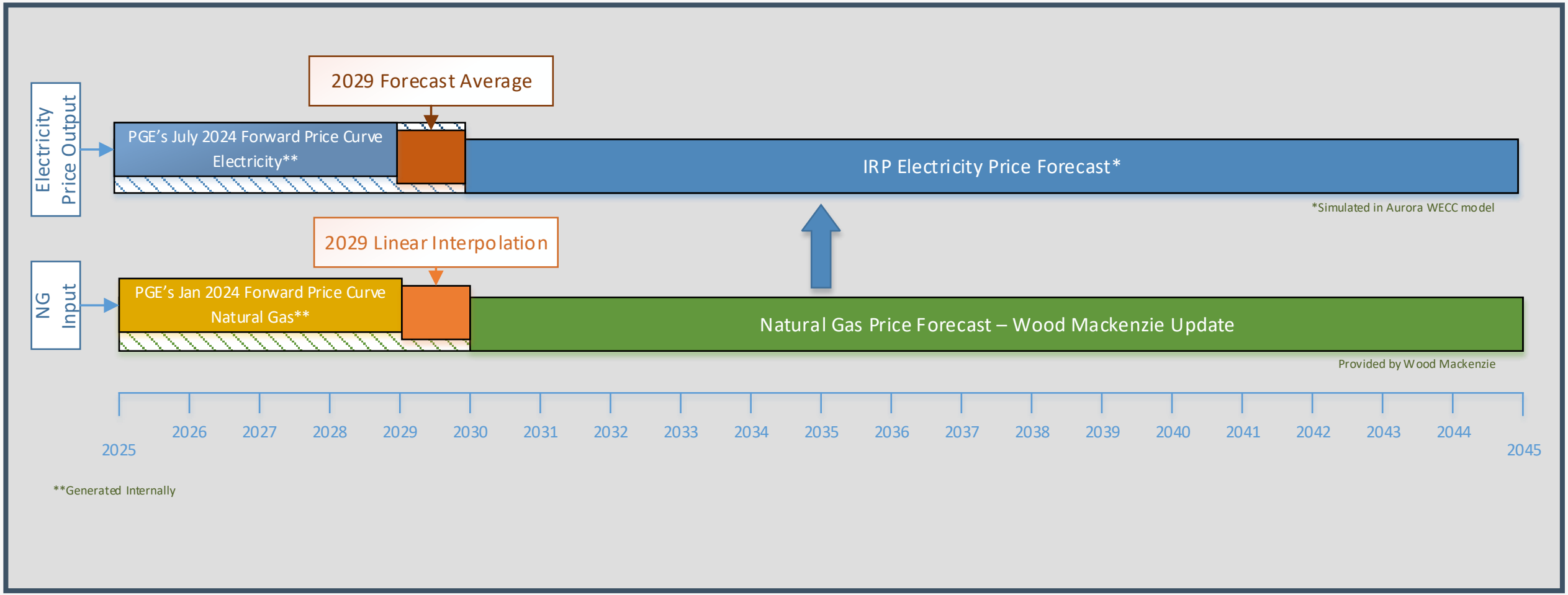
Change in Methodology for 2023 CEP/IRP Update:

To align with the Staff's recommendation in the UM 1893 docket, PGE will be incorporating the July 31, 2024 Snapshot of the Electric Forward Price Curve (FPC) as estimated by the PGE's Power Cost Forecasting Group using the Lydia Model to create hourly granularity.

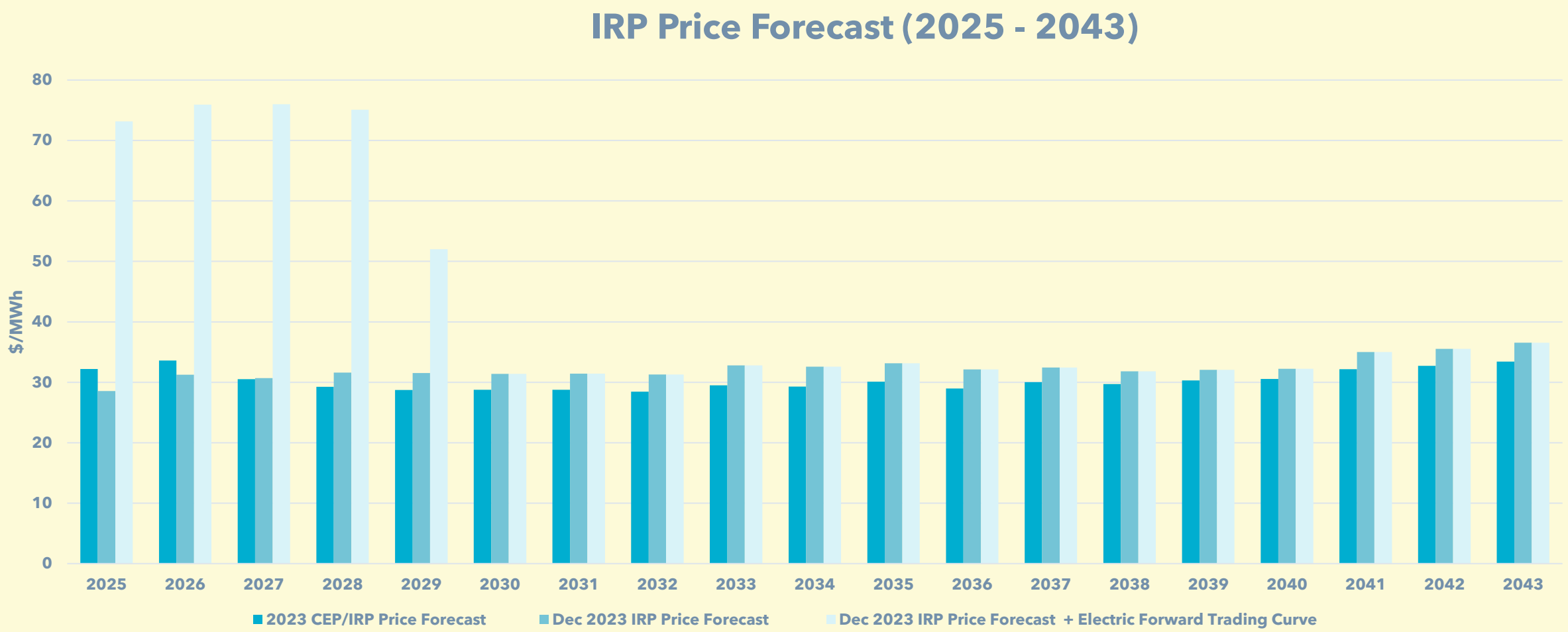
For reference case electricity prices:

- There is no change to the methodology for how the WECC simulated price forecast is created.
- 2025-2028 prices reflect PGE's Electric FPC.
- 2029 prices are an average of PGE's Electric FPC and WECC simulated price forecast.
- 2030-2045 prices are WECC simulated price forecast.

2023 CEP/IRP UPDATED Price Forecast



2023 CEP/IRP UPDATED Price Forecast



2023 CEP/IRP UPDATED Price Forecast

The methodological change in the IRP Price Forecast results in higher average prices between 2025-2029. We expect that these higher prices will lead to changes in the following variables for the 2023 CEP/IRP Update:

- Energy values
- Frequency of Variable Energy Resource (VER) curtailment
- Timing and quantity of thermal generation
- Thermal generation allocated to serve PGE load

Questions

NEXT STEPS

A recording from today's webinar will be available on our website in one week

Upcoming Roundtable: November 6th

Distribution System Workshop: October 24th

Thank you

Contact us at
IRP.CEP@PGN.COM

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ACRONYMS

ARIMA: autoregressive integrated moving average
ART: annual revenue-requirement tool
ATC available transfer capability
BE: Building Electrification
BPA: Bonneville Power Administration
C&I: commercial and industrial
CBI: community benefit indicators
CBIAG: community benefits and impacts advisory group
CBRE: community based renewable energy
CDD: colling degree day
CEC: California energy commission
CEP: clean energy plan
CF conditional firm
DC: direct current
DER: distributed energy resource
DR: demand response
DSP: distribution system plan
EE: energy efficiency
ELCC: effective load carrying capacity
EJ: environmental justice
ETO: energy trust of Oregon
EUI: energy use intensity
GHG: greenhouse gas
HB2021: House Bill 2021
HDD: heating degree day
HVDC: high-voltage direct current
HRCO: heat rate call option
IE: independent evaluator
IOU: investor-owned utilities
ITE: information technology equipment
ITC: investment tax credit
kW: kilowatt
LOLH: loss of load hours
LT/ST: long term/ short term
LTF long-term firm
MW: megawatt
MWa: mega watt average
NAICS: North American industry classification system
NCE: non-cost effective
NG: natural gas
NPVRR: net present value revenue requirement
OASIS Open Access Same Time Information System
ODOE: Oregon department of energy
PPA: power purchase agreement
PSH: pumped storage hydro
PUC: public utility commission
PURPA: Public Utility Regulatory Policies Act
PV: photovoltaic
REC: renewable energy credit
RLRR: low carbon price future
ROSE-E: resource option strategy engine
RPS: renewable portfolio standard
RRRR: reference case price future
RTO: regional transmission organization
SoA: South of Allston
TE: Transportation Electrification
T&D: transmission and distribution
TSR: transmission service request
TSEP: TSR study and expansion process
Tx: transmission
UPC: usage per customer
UPS: uninterruptible power supply
VER: variable energy resources
VPP: virtual power plant
WECC: western electricity coordinating council

Attachment 12. WECC Phase 2 Path Rating Study Plan, November 10, 2021

Cascade Renewable Transmission Project (CRTP)

HVDC Transmission Line Project

Rating: 1,100 MW DC

WECC Phase 2 Path Rating Study Plan

November 10, 2021

FINAL

Prepared by:
Jeffery L. Ellis of Utility System Efficiencies, Inc.

Reviewed by:
PRG Group members

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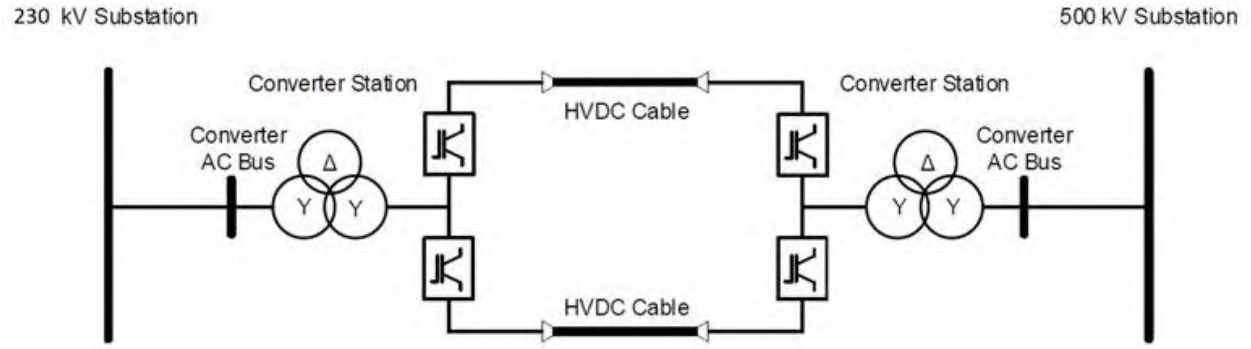
I. INTRODUCTION

Cascade Renewable Transmission, LLC (CRT) is developing the Cascade Renewable Transmission Project (CRTP) HVDC Transmission Line Project, an 1,100 MW transmission project in the western U.S. The studies outlined herein will determine Planned Rating to be requested as CRTP requests to enter Phase 2B of the WECC Path Rating Process.

The CRT is proposing a symmetrical monopolar Voltage-Source Converter-based High-Voltage Direct Current (VSC-HVDC) transmission system between the Big Eddy and Harborton 230 kV buses/substations (over 105 miles long), as shown in Figure 1. The project is envisioned to deliver 1,100 MW of renewable energy resources to the greater metropolitan area of Portland, Oregon. CRT anticipates the Cascades Renewable Transmission Project (CRTP) VSC-HVDC Project could potentially be in-service as early as 2026.

Figure 1 - CRTP VSC-HVDC Transmission Project



A summary of key elements of the CRTP VSC-HVDC Project are listed below.

- Eastern VSC-HVDC Terminal connected at the Big Eddy 500kV substation.
- A 105-mile ±320 kV, 1100 MW VSC-HVDC transmission cable.
- Western VSC-HVDC Terminal connected at the Harborton 230kV substation.

II. SCOPE OVERVIEW

The objective of this study plan is to outline steps necessary to demonstrate a 1,100 MW east to west and west to east Planned Rating for the VSC-HVDC line (measured at Harborton), consistent with the requirements of the WECC Path Rating Phase 2 study process.

The simultaneous rating will be based on using the following:

- Applicable NERC, WECC, CAISO and/or more stringent local performance requirements or criteria (see *Appendix 1*)
- Post-transient governor power flow solution techniques using GE PSLF v21.0 will be used to assess TPL-001-4 NERC P1, P2, P4 and P7 contingencies (see *Section V*).
- Transient stability contingency analysis for select TPL-001-4 NERC P1 and P7 contingencies (see *Section V*),

CRT will seek approval from the PRG and RAC/StS groups requesting Phase 3 status once all study results have been completed.

III. NON-SIMULTANEOUS ANALYSES

A non-simultaneous study will be performed to demonstrate a 1,100 MW east-to-west and a 1,100 MW west to east Path Rating (measured at the receiving end of the CRTP DC line) for the CRTP HVDC Project using the study methodology and contingencies described in Section V.

IV. SIMULTANEOUS ANALYSES

The Study Plan includes an assessment of the potential impact of the CRTP Project delivering 1,100 MW to the Harborton 230 kV bus and 1,100 MW to the Big Eddy 500 kV bus simultaneously with stressed flows on each of the following paths, taken one at a time or in logical groupings.

- WECC Path 5, WOCS, East to West (No Accepted Rating)
- WECC Path 65, PDCI, North to South
- WECC Path 66, COI, North to South
- WECC Path 71, South of Allston, North to South (No Accepted Rating)
- WECC Path 86, West of John Day, East to West

These paths were selected for simultaneous analysis based on results of the Ten Percent Test described in the WECC Project Rating Review Process for loss of the DC Line. The Ten Percent Test results are provided in Appendix 6.

Path 26 was not selected for a simultaneous interaction since the Ten Percent Test results identified that the flow difference was negligible and would not be impacted by the CRTP Project.

The simultaneous paths and case to be used that will be studied are provided in Table 1.

Table 1 – Interacting WECC Simultaneous Path Rating

WECC Path Name	WECC Path Rating (MW)		Base Case
CRTP Flow Direction	East to West	West to East	
Path 5, West of Cascades (E-W)†	5,930 (HS) / 7,200 (HW)	None	2026 HS / 2026 HW
Path 65, PDCI	3,220 (N-S) 3,100 (S-N) (Sensitivity)	3,220 (N-S) 3,100 (S-N) (Sensitivity)	2026 HS / 2026 HW 2024 LS (Sensitivity)
Path 66, COI	4,800 (N-S) / 3,675 (S-N)	4,800 (N-S) / 3,675 (S-N)	2026 HS / 2026 HW / 2024 LS (Sensitivity)
Path 71, South of Allston†	2,725 to 3,100 (N-S) 1,170 to 1,480 (S-N)	2,725 to 3,100 (N-S) 1,170 to 1,480 (S-N)	2026 HS
Path 86, West of John Day	4,760 (E-W)	4,760 (E-W)	2026 HS

†Identified WECC Path Name does not have an "Accepted" Path rating.

Aspects of this simultaneous analysis, including assumptions, methodology, and contingencies are covered in Section V of this Study Plan.

V. STUDY METHODOLOGY

The non-simultaneous study results will comply with NERC TPL-001-4 Standards as well as TPL-001-WECC-CRT-2.1 – System Performance Regional Criterion (Appendices 1 and 2).

a. Base Case *Development*

- The WECC 2026HS2 and 2025-2026HW2 planning base cases in GE PSLF v. 21.0.10.1 format will be used as the starting base case(s).
- The sensitivity analysis base case will use a 2024 light spring base case in GE PSLF v. 21.0.10.1 format.
- Project base cases will be developed with a CRTP Project flow of 1,100 MW (measured at Harborton).
- The HVDC system will be loaded with use of DC controls. No generation will be moved when loading the HVDC system for the non-simultaneous base case.
- Swing bus set to Laramie River PP (73129), out of region of study.
- No new WECC Rating Projects identified in the WECC Path Rating Process Logbook will have an impact to the proposed CRTP VSC-HVDC Project. As a result, no new WECC Rating Projects will be modeled in the CPR studied cases.

b. Power Flow Analysis

Study Assumptions:

a. A traditional power flow will be used for contingencies that do not trip generation.
b. The power flow voltage deviations should meet the TPL Standards and WECC system performance regional criterion.
c. No manual operator intervention is allowed to increase the generator MVAR flow.
d. Solution Setting Assumptions during Contingency Events

Area Interchange	Solution Status
Transformer Tap Automatic Adjustment (TCUL)	Disabled
Phase Shifter Control	Disabled
Area Interchange	Disabled
Switched Shunt Devices	Disable Type 3 and 4

e. Contingencies are provided in Appendix 3, Tables 3-1 and 3-2.

f. Any thermal loading greater than 98% of the branch rating with a thermal overload increase of 2% or more will be documented. Normal rating will be used for all lines in-service conditions and the emergency rating will be used during contingency analysis.

Study Criteria:

a. Steady-State Conditions
   i. Under steady-state conditions, bus voltages must be between 0.95 p.u. and 1.05 p.u., unless specific minimum operating voltage requirements exist.
   ii. Line and transformer loadings must be less than 100% of normal continuous ratings.

b. Contingency Conditions
   i. Changes in bus voltages from pre- to post-contingency conditions must be less than 8% for single contingencies, with exceptions noted in Appendix 1 and 2.
   ii. All line, series capacitors, and transformer loadings must not exceed their emergency ratings (or normal rating if no emergency rating is given), for P1, P2, P4 and P7 contingencies.
   iii. Under contingency conditions, bus voltages must be between 0.90 p.u. and 1.10 p.u., unless specific minimum operating voltage requirements exist.

c. Post-Transient Power Flow Analysis

Study Assumptions:

a. A governor power flow will be used for contingencies that trip generation.
b. The post-transient voltage deviations should meet the TPL Standards and WECC system performance regional criterion.
c. All loads will be modeled as constant MVA during the first few minutes following an outage or disturbance.
d. Generator MVAR limits (maximum and minimum) will be modeled as a single value for each generator since the reactive power capability curve will not be modeled in the program output.
e. No manual operator intervention is allowed to increase the generator MVAR flow.
f. Solution Setting Assumptions during Contingency Events

Area Interchange	Solution Status
Governor Blocking	Base load Flag will be used per WECC practices
DC Line and Transformer Tap Automatic Adjustment	Enabled
Generator Voltage Control	Set to local except for Palo Verde and selected Northwest generation
Phase Shifter Control	Disabled
Switched Shunt Devices	Disabled – except in Nevada Energy (Sierra Pacific) system and other locations that will move during the transient period.
Voltage-Source Converters	VSC will allow VAR movement during contingency

g. Contingencies are provided in Appendix 3, Tables 3-1 and 3-2.
h. Any thermal loading greater than 98% of the branch rating with a thermal overload increase of 2% or more will be documented. Normal rating will be used for all lines in-service conditions and the emergency rating will be used during contingency analysis.

Study Criteria:

a. Steady-State Conditions
   iii. Under steady-state conditions, bus voltages must be between 0.95 p.u. and 1.05 p.u., unless specific minimum operating voltage requirements exist.
   iv. Line and transformer loadings must be less than 100% of normal continuous ratings.

b. Contingency Conditions

iv. Changes in bus voltages from pre- to post-contingency conditions must be less than 8% for single contingencies, with exceptions noted in Appendix 1 and 2.

v. All line, series capacitors, and transformer loadings must not exceed their emergency ratings (or normal rating if no emergency rating is given), for P1, P2, P4 and P7 contingencies.

vi. Under contingency conditions, bus voltages must be between 0.90 p.u. and 1.10 p.u., unless specific minimum operating voltage requirements exist.

d. ***Post-Transient Voltage Stability Analysis:***

a. The WECC Voltage Stability Guidelines and Reactive Power Reserve Monitoring Methodology will be utilized in evaluating study results.

i. For P1 and P2 disturbances, a path is required to have positive reactive margin for a 5% increase beyond the maximum allowable MW flow on that path.

ii. For P4 and P7 disturbances, a path is required to have positive margin for a 2.5% increase beyond the maximum allowable MW flow on that path.

e. Transient Stability Analysis

Transient stability studies will be performed to assess the impact on the dynamic performance of the non-simultaneous base case.

Study Assumptions:

a. The Project will be represented using the vhvdc1 model with a voltage source converter-based HVDC (VSC-HVDC) transferring power to the western terminal.
b. All transient stability contingencies will be performed to a minimum of 20 seconds.
c. While specific tripping schemes will be utilized for the Palo Verde double unit trip disturbance, the following timing will be used for faults:
   230 kV lines – 5 cycles (6 cycles for PG&E)
   345 kV lines – 4 cycles (3 cycles for Idaho system)
   500 kV lines - 4 cycles (3 cycles for Midpoint 500 kV)
d. List of contingencies are provided in Appendix 3, Tables 3-3 and 3-4.

Study Criteria:

a. System stability is evaluated based on the damping of the relative rotor angles and the damping of the voltage magnitude swings.
b. Transient voltage dips and duration requirements must meet TPL Standards and WECC system performance criteria as shown in Appendix 2.

f. Nomogram(s)

As part of the simultaneous analysis that will be performed, changes to existing nomograms (if necessary) will be determined or new nomograms will be defined if impacts to other simultaneous ratings are identified.

g. Project *Review* Group

To assure that the appropriate system conditions are included in the study, a Project Review Group has been formed to provide input. The participants will represent various areas impacted by the CRTP Project.

h. Path Ratings

The Path Rating for the CRTP Project requires simultaneous studies that may include reevaluating existing Path Ratings and identifying new transmission paths. A tabulation of interacting paths is provided in Table 1.

These paths were selected for simultaneous analysis based on results of the Ten Percent Test described in the WECC Project Rating Review Process for a CRTP HVDC outage of the CRTP Project. The Ten Percent Test results are provided in Appendix 5.

Other paths may be identified during the study and will be added as appropriate.

i. Mitigation Options

To the extent a need to mitigate criteria violations or interaction with Existing/Accepted Path Ratings is identified from the simultaneous path analyses, viable mitigation options will be identified in this Phase 2 Study Group Technical Report, including the following:

1. Added Facilities
2. Operating Procedures and/or Operating Nomograms

The detailed design of the mitigation plan will be developed during Phase 3 of the Project Rating Review Process, prior to facilities becoming commercial, or as part of the Operating Transfer Capability (OTC) technical studies.

VI. SENSITIVITY CASES

This Project may have benefits to the COI during heavy south to north flow.

1. California Oregon Intertie, Path 66 flow: Addition of the CRTP may have benefits to COI during heavy south to north flow. The sensitivity study will simulate maximum south to north COI flow (3,675 MW) with use of the 2024 light spring base case. The sensitivity base case will model south to north flow for South of Allston (350 MW) and maximum PDCI (3,100 MW) flow.

VII. SUB-SYNCHRONOUS SCREENING ANALYSIS

Sub-synchronous torsional interactions (SSTI) associated with HVDC converters are important topics for the CRTP Project. Because SSTI studies is typically not included in Phase 2 rating studies it is not included in this Study Plan. SSTI issues will be addressed in design studies (Phase 3) for the CRTP Project, and/or interconnection studies with other transmission providers.

As part of its design studies, CRT will conduct screening studies to identify any potential SSTI effects between the CRTP Project HVDC converters and local area generators in the CRTP Terminal areas. Additional generators will be evaluated if requested by Project Review Group members prior to the beginning of the screening studies. The results of the screening studies will be provided to the Project Review Group prior to CRTP requesting an Accepted Rating. If any issues are identified, they will be analyzed in detail when an HVDC vendor is selected.

SSTI screening analysis will be per the methodology provided in EPRI Report, "HVDC system Control for Damping of Sub-Synchronous Oscillations – EPRI EL-2708". Generator Unit Interaction Factor (UIF) will be calculated, as given below, for each of the generators under consideration:

$$UIF = \frac{MVAdc}{MVAg}\left(1 - \frac{SCg}{SCdc}\right)^2$$

Where,
UIF: Unit Interaction Factor

MVAdc: HVDC Converter Rating

MVAg: Rating of the Generator under study

SCg: Short Circuit Capacity at the HVDC Commutating Bus, excluding the generator under study

SCdc: Short Circuit Capacity at the HVDC Commutating Bus, including the generator under study

As per EPRI Report, a generator with an UIF of less than 0.1 will not have a significant interaction and need not be considered for detailed SSTI analysis.

VIII. SHORT CIRCUIT ANALYSIS

CRTP will not evaluate short circuit impacts since the DC Project does not contribute to short circuit fault duties.

X. SCHEDULE

The study schedule for the CRTP VSC-HVDC Project is provided below.

Table 3. CRTP VSC-HVDC Project Study Schedule

Action	Completion Date
Approved WECC Phase 1 Report from RAC/StS	June 2021
PRG Meeting 1 – Kick Off Meeting	June 2021
Approve WECC Phase 2 Study Plan	November 2021
Approve Foundational Base Case	November 2021
WECC Phase 2B Status	November 2021
Begin WECC Phase 2B Studies	November 2021
PRG Meeting 2 – Status of work performed to date	December 2021
Continue WECC Phase 2B Studies	December-February 2022
PRG Meeting 3 – Status of work performed to date	February 2022
DRAFT Report to PRG	February 2022
Final Draft Report for PRG Approval	March 2022
Final WECC Phase 2B Report to RAC/StS for Review	March 2022
Approved WECC Phase 3 Status	May 2022

APPENDIX 1 - Minimum Voltage Limits

Bus Voltage Exceptions

Bus	Pre-Outage Min. Volt (p.u.)	Post-Disturbance Min. Volt (p.u.)	Comments
BPA	0.95 – 1.05	0.90 – 1.10	
PGE	0.95 – 1.05	0.90 – 1.10	*Also, see below*
PacifiCorp	0.95 – 1.05	0.90 – 1.10	

PGE Voltage Limits

			Pre-Contingency Voltage Range		Contingency Voltage Range	
Bus Number	Name	Nom kV	Low PU Volt	High PU Volt	Low PU Volt	High PU Volt
43001	ABRNATHY	115	0.975	1.077	0.923	1.129
43005	ABRNTHY1	115	0.975	1.077	0.923	1.129
43007	ALDERCRT	115	0.975	1.077	0.923	1.129
43009	AMITY	59.8	0.964	1.065	0.913	1.116
43011	ARLETA	59.8	0.964	1.065	0.913	1.116
43013	BANKS	59.8	0.964	1.065	0.913	1.116
43014	BASIN TP	115	0.975	1.077	0.923	1.129
43015	BARNES	115	0.975	1.077	0.923	1.129
43016	BASIN AV	115	0.975	1.077	0.923	1.129
43021	BEAVER	230	0.979	1.082	0.927	1.133
43029	BEAVRTON	115	0.975	1.077	0.923	1.129
43033	BELL	115	0.975	1.077	0.923	1.129
43035	BETHEL	59.8	0.964	1.065	0.913	1.116
43037	BETHEL	115	0.975	1.077	0.923	1.129
43039	BETHEL	230	0.979	1.082	0.927	1.133
43043	BETHELSO	115	0.975	1.077	0.923	1.129
43046	CARTY	500	1.031	1.139	0.977	1.194
43048	GRASSLND	500	1.031	1.139	0.977	1.194
43050	CARTYM1	500	1.031	1.139	0.977	1.194
43053	BOISECSC	115	0.975	1.077	0.923	1.129
43054	CORNEL	115	0.975	1.077	0.923	1.129
43055	BETHANY	115	0.975	1.077	0.923	1.129
43056	CORNEL #	115	0.975	1.077	0.923	1.129
43057	BOONESFR	115	0.975	1.077	0.923	1.129
43059	BORING	59.8	0.964	1.065	0.913	1.116
43061	BRGHTWD	59.8	0.964	1.065	0.913	1.116
43063	BRGHTWD2	59.8	0.964	1.065	0.913	1.116
43068	BROOKWOOD	115	0.975	1.077	0.923	1.129
43070	BUTLER	115	0.975	1.077	0.923	1.129

			Pre-Contingency Voltage Range		Contingency Voltage Range	
Bus Number	Name	Nom kV	Low PU Volt	High PU Volt	Low PU Volt	High PU Volt
43077	CANBY	59.8	0.964	1.065	0.913	1.116
43078	CANBYTP1	59.8	0.964	1.065	0.913	1.116
43079	CANBYTP2	59.8	0.964	1.065	0.913	1.116
43081	CANEMAH	59.8	0.964	1.065	0.913	1.116
43082	CANEMAH_W	59.8	0.964	1.065	0.913	1.116
43083	CANEMAH	115	0.975	1.077	0.923	1.129
43085	CANYON	115	0.975	1.077	0.923	1.129
43087	CARVER	115	0.975	1.077	0.923	1.129
43088	CARVER B	115	0.975	1.077	0.923	1.129
43089	CARVER	230	0.979	1.082	0.927	1.133
43091	CEDARHIL	115	0.975	1.077	0.923	1.129
43092	CORN TP2	115	0.975	1.077	0.923	1.129
43093	CENTURY	115	0.975	1.077	0.923	1.129
43095	CLACKMAS	115	0.975	1.077	0.923	1.129
43097	CLAXTAR	59.8	0.964	1.065	0.913	1.116
43099	CNTENIAL	115	0.975	1.077	0.923	1.129
43101	CNTENL 1	115	0.975	1.077	0.923	1.129
43103	CNTENL 2	115	0.975	1.077	0.923	1.129
43105	COLTON	59.8	0.964	1.065	0.913	1.116
43107	CORNELUS	59.8	0.964	1.065	0.913	1.116
43109	CORNELUS	115	0.975	1.077	0.923	1.129
43115	COYO M1	500	1.031	1.139	0.977	1.194
43123	COYOTE	500	1.031	1.139	0.977	1.194
43126	CULVER	115	0.975	1.077	0.923	1.129
43137	DAYTON	59.8	0.964	1.065	0.913	1.116
43138	DAYTON_TAP	115	0.975	1.077	0.923	1.129
43139	DAYTON	115	0.975	1.077	0.923	1.129
43143	DELAWARE	115	0.975	1.077	0.923	1.129
43145	DENNY	115	0.975	1.077	0.923	1.129
43147	DILLEY	59.8	0.964	1.065	0.913	1.116
43149	DUNSCRN2	59.8	0.964	1.065	0.913	1.116
43151	DUNSCRNR	59.8	0.964	1.065	0.913	1.116
43157	E SUBSTA	115	0.975	1.077	0.923	1.129
43159	EAGLCRK1	59.8	0.964	1.065	0.913	1.116
43161	EAGLCRK2	59.8	0.964	1.065	0.913	1.116
43163	EAGLECRK	59.8	0.964	1.065	0.913	1.116
43165	EASTPORT	115	0.975	1.077	0.923	1.129
43167	ELMA	59.8	0.964	1.065	0.913	1.116

			Pre-Contingency Voltage Range		Contingency Voltage Range	
Bus Number	Name	Nom kV	Low PU Volt	High PU Volt	Low PU Volt	High PU Volt
43169	ELMA 2	59.8	0.964	1.065	0.913	1.116
43171	ESTACAD1	59.8	0.964	1.065	0.913	1.116
43173	ESTACAD2	59.8	0.964	1.065	0.913	1.116
43175	ESTACADA	59.8	0.964	1.065	0.913	1.116
43181	FAIRMNT	115	0.975	1.077	0.923	1.129
43185	FAIRVW P	115	0.975	1.077	0.923	1.129
43191	FARADAY	59.8	0.964	1.065	0.913	1.116
43193	FARADAY	115	0.975	1.077	0.923	1.129
43195	FARGO	115	0.975	1.077	0.923	1.129
43197	STMSNLBR	59.8	0.964	1.065	0.913	1.116
43199	GALES CR	59.8	0.964	1.065	0.913	1.116
43200	GALES TP	59.8	0.964	1.065	0.913	1.116
43201	GLENCOE	115	0.975	1.077	0.923	1.129
43205	GLENCULN	115	0.975	1.077	0.923	1.129
43207	GLNDOVER	115	0.975	1.077	0.923	1.129
43209	GRDNHOM1	115	0.975	1.077	0.923	1.129
43211	GRDNHOM2	115	0.975	1.077	0.923	1.129
43213	GRDNHOME	115	0.975	1.077	0.923	1.129
43215	GRESHAM	230	0.979	1.082	0.927	1.133
43217	GRESHAMA	115	0.975	1.077	0.923	1.129
43219	GRESHAMB	115	0.975	1.077	0.923	1.129
43221	GRNDROND	59.8	0.964	1.065	0.913	1.116
43223	GRNDROND	115	0.975	1.077	0.923	1.129
43227	HARBORTN	115	0.975	1.077	0.923	1.129
43229	HARBORTN	230	0.979	1.082	0.927	1.133
43235	HARMONY	115	0.975	1.077	0.923	1.129
43237	HARSNPGE	115	0.975	1.077	0.923	1.129
43240	HELVETIA	115	0.975	1.077	0.923	1.129
43241	HEMLCK	115	0.975	1.077	0.923	1.129
43245	HILSBOR1	59.8	0.964	1.065	0.913	1.116
43247	HILSBOR2	59.8	0.964	1.065	0.913	1.116
43249	HILSBORO	59.8	0.964	1.065	0.913	1.116
43251	HOGAN	59.8	0.964	1.065	0.913	1.116
43252	HOGAN N	115	0.975	1.077	0.923	1.129
43253	HOGAN	115	0.975	1.077	0.923	1.129
43254	HOGAN #1	115	0.975	1.077	0.923	1.129
43255	HOGAN #2	115	0.975	1.077	0.923	1.129
43257	HOLGATE	59.8	0.964	1.065	0.913	1.116

			Pre-Contingency Voltage Range		Contingency Voltage Range	
Bus Number	Name	Nom kV	Low PU Volt	High PU Volt	Low PU Volt	High PU Volt
43259	HUBER	115	0.975	1.077	0.923	1.129
43260	HLGTTAP	59.8	0.964	1.065	0.913	1.116
43263	HYDN ISL	115	0.975	1.077	0.923	1.129
43265	INDIAN	115	0.975	1.077	0.923	1.129
43267	ISLAND	115	0.975	1.077	0.923	1.129
43269	WLINN	59.8	0.964	1.065	0.913	1.116
43273	JENGSLD2	115	0.975	1.077	0.923	1.129
43275	JENGSLDG	115	0.975	1.077	0.923	1.129
43277	KELYBUTE	115	0.975	1.077	0.923	1.129
43279	KINGCITY	115	0.975	1.077	0.923	1.129
43280	LELAND	59.8	0.964	1.065	0.913	1.116
43281	LENTS	59.8	0.964	1.065	0.913	1.116
43283	LENTS	115	0.975	1.077	0.923	1.129
43285	LIBERAL	59.8	0.964	1.065	0.913	1.116
43291	LINNEMAN	230	0.979	1.082	0.927	1.133
43299	MAIN ST	59.8	0.964	1.065	0.913	1.116
43301	MAIN ST1	59.8	0.964	1.065	0.913	1.116
43303	MAIN ST2	59.8	0.964	1.065	0.913	1.116
43307	MCCLAIN	59.8	0.964	1.065	0.913	1.116
43309	MCLGHLNA	115	0.975	1.077	0.923	1.129
43311	MCLGHLNB	115	0.975	1.077	0.923	1.129
43313	MCLOUGLN	230	0.979	1.082	0.927	1.133
43314	MCLOUGE5	230	0.979	1.082	0.927	1.133
43315	MERIDIAN	115	0.975	1.077	0.923	1.129
43316	MIDLGROV	115	0.975	1.077	0.923	1.129
43318	MIDGRV #	115	0.975	1.077	0.923	1.129
43319	MIDWAYTP2	115	0.975	1.077	0.923	1.129
43320	MIDWAYTP1	115	0.975	1.077	0.923	1.129
43321	MIDWAYPG	115	0.975	1.077	0.923	1.129
43323	MOLALLAN	59.8	0.964	1.065	0.913	1.116
43327	MONITOR	59.8	0.964	1.065	0.913	1.116
43328	MONITORTAP	230	0.979	1.082	0.927	1.133
43329	MONITOR	230	0.979	1.082	0.927	1.133
43331	MT ANGEL	59.8	0.964	1.065	0.913	1.116
43333	MT PLSN1	115	0.975	1.077	0.923	1.129
43335	MT PLSN2	115	0.975	1.077	0.923	1.129
43337	MT PLSNT	115	0.975	1.077	0.923	1.129
43339	MULINO	59.8	0.964	1.065	0.913	1.116

			Pre-Contingency Voltage Range		Contingency Voltage Range	
Bus Number	Name	Nom kV	Low PU Volt	High PU Volt	Low PU Volt	High PU Volt
43345	MULTNMAH	115	0.975	1.077	0.923	1.129
43347	MURRAY H	115	0.975	1.077	0.923	1.129
43348	MURRAY H	230	0.979	1.082	0.927	1.133
43349	SCHOLFRY	115	0.975	1.077	0.923	1.129
43353	N MARION	59.8	0.964	1.065	0.913	1.116
43355	N PLAINS	59.8	0.964	1.065	0.913	1.116
43357	NEWBERG	115	0.975	1.077	0.923	1.129
43361	NORTH FK	115	0.975	1.077	0.923	1.129
43364	NORTHERN	115	0.975	1.077	0.923	1.129
43370	OAKGROVE_W	115	0.975	1.077	0.923	1.129
43371	OAKGROVE	115	0.975	1.077	0.923	1.129
43372	LKHARIET	115	0.975	1.077	0.923	1.129
43376	COVANTTP	59.8	0.964	1.065	0.913	1.116
43377	COVANTA	59.8	0.964	1.065	0.913	1.116
43379	ORENCO	59.8	0.964	1.065	0.913	1.116
43380	ORENCO_N	59.8	0.964	1.065	0.913	1.116
43381	ORENCO	115	0.975	1.077	0.923	1.129
43383	ORENCO 1	115	0.975	1.077	0.923	1.129
43387	ORESTEEL	115	0.975	1.077	0.923	1.129
43389	ORIENT	59.8	0.964	1.065	0.913	1.116
43393	OSWEGO	115	0.975	1.077	0.923	1.129
43409	PELTON	230	0.979	1.082	0.927	1.133
43410	PEN PARK	115	0.975	1.077	0.923	1.129
43411	PEN TP1	115	0.975	1.077	0.923	1.129
43414	PEN TP2	115	0.975	1.077	0.923	1.129
43415	MILL CR	115	0.975	1.077	0.923	1.129
43419	PLSNTVLY	115	0.975	1.077	0.923	1.129
43421	PORTSMTH	115	0.975	1.077	0.923	1.129
43423	PROGRESS	115	0.975	1.077	0.923	1.129
43427	PTLBRUN1	59.8	0.964	1.065	0.913	1.116
43431	PTLBRUN2	59.8	0.964	1.065	0.913	1.116
43439	RALGHHIL	115	0.975	1.077	0.923	1.129
43443	RAMAPO	115	0.975	1.077	0.923	1.129
43444	RAMAPOTP1	115	0.975	1.077	0.923	1.129
43447	REDLAND	115	0.975	1.077	0.923	1.129
43449	REDLAND1	115	0.975	1.077	0.923	1.129
43451	REDLAND2	115	0.975	1.077	0.923	1.129
43453	REEDVILE	115	0.975	1.077	0.923	1.129

			Pre-Contingency Voltage Range		Contingency Voltage Range	
Bus Number	Name	Nom kV	Low PU Volt	High PU Volt	Low PU Volt	High PU Volt
43455	RHODODEN	59.8	0.964	1.065	0.913	1.116
43459	RIVRGATE	230	0.979	1.082	0.927	1.133
43461	RIVRGT A	115	0.975	1.077	0.923	1.129
43463	RIVRGT B	115	0.975	1.077	0.923	1.129
43464	RVRGT B#	115	0.975	1.077	0.923	1.129
43467	RIVRMILL	59.8	0.964	1.065	0.913	1.116
43469	RIVRVIEW	115	0.975	1.077	0.923	1.129
43471	RIVRVW 1	115	0.975	1.077	0.923	1.129
43473	ROCKCRTAP	115	0.975	1.077	0.923	1.129
43474	ROCKCREEK	115	0.975	1.077	0.923	1.129
43475	ROCKWD	115	0.975	1.077	0.923	1.129
43476	ROCKWD1	115	0.975	1.077	0.923	1.129
43477	ROCKWD2	115	0.975	1.077	0.923	1.129
43479	ROSEMONT	115	0.975	1.077	0.923	1.129
43481	ROSEWAY	115	0.975	1.077	0.923	1.129
43482	ROUNDB S	230	0.979	1.082	0.927	1.133
43483	ROUNDB N	230	0.979	1.082	0.927	1.133
43484	RUBY	115	0.975	1.077	0.923	1.129
43485	ROUND BU	500	1.031	1.139	0.977	1.194
43487	ROUNDB_STR	500	1.031	1.139	0.977	1.194
43497	SALEM	59.8	0.964	1.065	0.913	1.116
43499	SANDY	59.8	0.964	1.065	0.913	1.116
43503	SANDY 2	59.8	0.964	1.065	0.913	1.116
43507	BETSY_J#	115	0.975	1.077	0.923	1.129
43509	SCHNTZTAP	115	0.975	1.077	0.923	1.129
43510	SCHNTZER	115	0.975	1.077	0.923	1.129
43511	SCOGGIN	59.8	0.964	1.065	0.913	1.116
43513	SCOTTMIL	59.8	0.964	1.065	0.913	1.116
43517	SELLWOOD	59.8	0.964	1.065	0.913	1.116
43519	SELLWOOD	115	0.975	1.077	0.923	1.129
43521	SHERIDAN	59.8	0.964	1.065	0.913	1.116
43523	SHERWD A	115	0.975	1.077	0.923	1.129
43525	SHERWD B	115	0.975	1.077	0.923	1.129
43527	SHERWOOD	230	0.979	1.082	0.927	1.133
43529	SILVRTON	59.8	0.964	1.065	0.913	1.116
43531	SIXCRNRS	115	0.975	1.077	0.923	1.129
43533	SPNWSPR1	115	0.975	1.077	0.923	1.129
43535	SPNWSPR	115	0.975	1.077	0.923	1.129

			Pre-Contingency Voltage Range		Contingency Voltage Range	
Bus Number	Name	Nom kV	Low PU Volt	High PU Volt	Low PU Volt	High PU Volt
43537	BHERON	59.8	0.964	1.065	0.913	1.116
43538	BHERON#	59.8	0.964	1.065	0.913	1.116
43539	ST LOUIS	59.8	0.964	1.065	0.913	1.116
43541	ST MARYS	230	0.979	1.082	0.927	1.133
43544	STHELENS_N	115	0.975	1.077	0.923	1.129
43545	STHELENS	115	0.975	1.077	0.923	1.129
43547	STMARYE1	115	0.975	1.077	0.923	1.129
43549	STMARYE2	115	0.975	1.077	0.923	1.129
43551	STMARYES	115	0.975	1.077	0.923	1.129
43553	STMARYSA	115	0.975	1.077	0.923	1.129
43555	STMARYSB	115	0.975	1.077	0.923	1.129
43557	SULIVAN	59.8	0.964	1.065	0.913	1.116
43558	SULIVAN #	59.8	0.964	1.065	0.913	1.116
43559	SULIVAN	115	0.975	1.077	0.923	1.129
43560	N MARION #	59.8	0.964	1.065	0.913	1.116
43563	SUMMIT	59.8	0.964	1.065	0.913	1.116
43570	SWAN TAP	115	0.975	1.077	0.923	1.129
43572	SWAN ISL	115	0.975	1.077	0.923	1.129
43573	SYLVAN	115	0.975	1.077	0.923	1.129
43574	SWAN TP2	115	0.975	1.077	0.923	1.129
43576	SWAN TP1	115	0.975	1.077	0.923	1.129
43577	SYLVAN 2	115	0.975	1.077	0.923	1.129
43579	TABOR	59.8	0.964	1.065	0.913	1.116
43581	TABOR	115	0.975	1.077	0.923	1.129
43585	TEKTRONX	115	0.975	1.077	0.923	1.129
43587	TIGARD	115	0.975	1.077	0.923	1.129
43589	TIGARD 1	115	0.975	1.077	0.923	1.129
43591	TIGARD 2	115	0.975	1.077	0.923	1.129
43595	TOWNCNTR	115	0.975	1.077	0.923	1.129
43597	TROJAN	230	0.979	1.082	0.927	1.133
43599	TROJAN_V81	230	0.979	1.082	0.927	1.133
43600	SPRNGVIL	230	0.979	1.082	0.927	1.133
43601	TROJAN_V82	230	0.979	1.082	0.927	1.133
43603	TUALATIN	115	0.975	1.077	0.923	1.129
43605	TURNER	115	0.975	1.077	0.923	1.129
43611	TWILIGHT	59.8	0.964	1.065	0.913	1.116
43613	TWR22-4N	115	0.975	1.077	0.923	1.129
43615	TWR22-4S	115	0.975	1.077	0.923	1.129

			Pre-Contingency Voltage Range		Contingency Voltage Range	
Bus Number	Name	Nom kV	Low PU Volt	High PU Volt	Low PU Volt	High PU Volt
43617	UNIONVLE	59.8	0.964	1.065	0.913	1.116
43619	UNVSTYPG	115	0.975	1.077	0.923	1.129
43620	URBAN_N	115	0.975	1.077	0.923	1.129
43621	URBAN_M1	115	0.975	1.077	0.923	1.129
43622	URBAN_M2	115	0.975	1.077	0.923	1.129
43623	URBAN_S	115	0.975	1.077	0.923	1.129
43627	WACKER	115	0.975	1.077	0.923	1.129
43628	WACKER_W	115	0.975	1.077	0.923	1.129
43631	WACONDA	59.8	0.964	1.065	0.913	1.116
43633	WALACERD	59.8	0.964	1.065	0.913	1.116
43635	WELCHES	59.8	0.964	1.065	0.913	1.116
43636	WILLAMINA1	59.8	0.964	1.065	0.913	1.116
43638	WILLAMINATP1	59.8	0.964	1.065	0.913	1.116
43639	WELCHES2	59.8	0.964	1.065	0.913	1.116
43641	WILLAMINA2	59.8	0.964	1.065	0.913	1.116
43642	WILLAMINATP2	59.8	0.964	1.065	0.913	1.116
43643	WLBRSHOOFLY	115	0.964	1.065	0.913	1.116
43644	WLBRSHOOFLYTP	115	0.975	1.077	0.923	1.129
43645	WILLBRDG	115	0.975	1.077	0.923	1.129
43646	WLBRTP2	115	0.975	1.077	0.923	1.129
43647	WILLPENN	115	0.975	1.077	0.923	1.129
43650	WILSNVIL	115	0.975	1.077	0.923	1.129
43651	SULZER	115	0.975	1.077	0.923	1.129
43652	COFF TAP	115	0.975	1.077	0.923	1.129
43653	COFF CR	115	0.975	1.077	0.923	1.129
43654	COFF TP2	115	0.975	1.077	0.923	1.129
43655	WOODBURN	59.8	0.964	1.065	0.913	1.116
43657	WSTPRTLD	115	0.975	1.077	0.923	1.129
43662	WSTUNION	115	0.975	1.077	0.923	1.129
43663	YAMHILL	59.8	0.964	1.065	0.913	1.116
43684	BLUELAKE	115	0.975	1.077	0.923	1.129
43685	BLUELAKE	230	0.979	1.082	0.927	1.133
43686	BLUELAKE2	115	0.975	1.077	0.923	1.129
43691	CURTISPG	115	0.975	1.077	0.923	1.129
43693	DURHAM	115	0.975	1.077	0.923	1.129
43694	DURHAM 1	115	0.975	1.077	0.923	1.129
43695	DURHAM 2	115	0.975	1.077	0.923	1.129
43697	GLISAN	115	0.975	1.077	0.923	1.129

			Pre-Contingency Voltage Range		Contingency Voltage Range	
Bus Number	Name	Nom kV	Low PU Volt	High PU Volt	Low PU Volt	High PU Volt
43701	SPRNGBRK	115	0.975	1.077	0.923	1.129
43704	HILLCRST	115	0.975	1.077	0.923	1.129
43706	HUBER 1	115	0.975	1.077	0.923	1.129
43707	HUBER 2	115	0.975	1.077	0.923	1.129
43709	KP TAP	115	0.975	1.077	0.923	1.129
43710	KELLEYPT	115	0.975	1.077	0.923	1.129
43713	MARKET	115	0.975	1.077	0.923	1.129
43715	MCGILL	115	0.975	1.077	0.923	1.129
43719	OAKHILL2	115	0.975	1.077	0.923	1.129
43720	OAKHILLS	115	0.975	1.077	0.923	1.129
43737	STMARYSC	115	0.975	1.077	0.923	1.129
43739	SUNSETPG	115	0.975	1.077	0.923	1.129
43740	HORIZN	230	0.979	1.082	0.927	1.133
43741	TEK 1	115	0.975	1.077	0.923	1.129
43742	SHUTE	115	0.975	1.077	0.923	1.129
43743	HORIZN1	115	0.975	1.077	0.923	1.129
43744	HORIZN2	115	0.975	1.077	0.923	1.129
43745	HORIZN3	115	0.975	1.077	0.923	1.129
43750	ABRNTHY#	115	0.975	1.077	0.923	1.129
43752	BEAVTN #	115	0.975	1.077	0.923	1.129
43754	CANBY #	59.8	0.964	1.065	0.913	1.116
43755	CEDARHL#	115	0.975	1.077	0.923	1.129
43756	CLACKMA#	115	0.975	1.077	0.923	1.129
43761	GLENCOE#	115	0.975	1.077	0.923	1.129
43763	HEMLOCK#	115	0.975	1.077	0.923	1.129
43764	BARNESTP1	115	0.975	1.077	0.923	1.129
43765	HOGAN #	59.8	0.964	1.065	0.913	1.116
43766	JENGSL #	115	0.975	1.077	0.923	1.129
43767	LIBTY PG	115	0.975	1.077	0.923	1.129
43768	BARNESTP2	115	0.975	1.077	0.923	1.129
43769	MULTNM2#	115	0.975	1.077	0.923	1.129
43770	MULTNMA#	115	0.975	1.077	0.923	1.129
43772	ARMSTRONG#	115	0.975	1.077	0.923	1.129
43773	PEARL #	230	0.979	1.082	0.927	1.133
43776	RAINIER#	115	0.975	1.077	0.923	1.129
43777	RALGHHL#	115	0.975	1.077	0.923	1.129
43778	RAMAPO #	115	0.975	1.077	0.923	1.129
43779	HLGTTAP2	59.8	0.964	1.065	0.913	1.116

			Pre-Contingency Voltage Range		Contingency Voltage Range	
Bus Number	Name	Nom kV	Low PU Volt	High PU Volt	Low PU Volt	High PU Volt
43781	SALEMAL#	115	0.975	1.077	0.923	1.129
43782	SANDY #	59.8	0.964	1.065	0.913	1.116
43784	SCOTTML#	59.8	0.964	1.065	0.913	1.116
43786	SYLVAN #	115	0.975	1.077	0.923	1.129
43787	HARMONYTP1	115	0.975	1.077	0.923	1.129
43788	TURNER #	115	0.975	1.077	0.923	1.129
43790	URBAN #	115	0.975	1.077	0.923	1.129
43792	WILBRDG#	115	0.975	1.077	0.923	1.129
43793	SULZER #	115	0.975	1.077	0.923	1.129
43795	OXFRD PG	115	0.975	1.077	0.923	1.129
43800	BOISE #	115	0.975	1.077	0.923	1.129
43801	CARVER1	115	0.975	1.077	0.923	1.129
43802	CARVERLD	115	0.975	1.077	0.923	1.129
43806	MURAY LD	115	0.975	1.077	0.923	1.129
43807	MURRAY#1	115	0.975	1.077	0.923	1.129
43808	MURRAY#2	115	0.975	1.077	0.923	1.129
43809	OAKHILL1	115	0.975	1.077	0.923	1.129
43810	ORENCO 2	115	0.975	1.077	0.923	1.129
43811	ORENCOLD	115	0.975	1.077	0.923	1.129
43812	POT ASH	115	0.975	1.077	0.923	1.129
43813	POT ASH1	115	0.975	1.077	0.923	1.129
43814	RVGT SO1	115	0.975	1.077	0.923	1.129
43815	RVGTSOUTH	115	0.975	1.077	0.923	1.129
43816	WSTPRT	115	0.975	1.077	0.923	1.129
43817	WSTPRT 1	115	0.975	1.077	0.923	1.129
43818	WSTPRT 2	115	0.975	1.077	0.923	1.129
43819	CARVER2	115	0.975	1.077	0.923	1.129
43820	MARQUAM	115	0.975	1.077	0.923	1.129
43821	MAXIM	115	0.975	1.077	0.923	1.129
43822	MIDGRV 2	115	0.975	1.077	0.923	1.129
43823	CLAXTAR#	59.8	0.964	1.065	0.913	1.116
43824	RVGTSOTAP	115	0.975	1.077	0.923	1.129
43825	MAXIMTP1	115	0.975	1.077	0.923	1.129
43826	MAXIMTP2	115	0.975	1.077	0.923	1.129
43827	MAXIM1	115	0.975	1.077	0.923	1.129
43828	MAXIM2	115	0.975	1.077	0.923	1.129
43906	PORTW_STR	230	0.979	1.082	0.927	1.133
43909	PORTW	230	0.979	1.082	0.927	1.133

			Pre-Contingency Voltage Range		Contingency Voltage Range	
Bus Number	Name	Nom kV	Low PU Volt	High PU Volt	Low PU Volt	High PU Volt
43912	PORTW2SR1	230	0.979	1.082	0.923	1.129
43915	PORTW2SR2	230	0.979	1.082	0.923	1.129
43950	MULLAN	230	0.979	1.082	0.927	1.133
43960	MALIN R2	500	1.031	1.139	0.977	1.194
43990	SAND_SP_21	500	1.031	1.139	0.977	1.194
43991	SAND_SP_22	500	1.031	1.139	0.977	1.194
43992	FORT_RK_21	500	1.031	1.139	0.977	1.194
43993	FORT_RK_22	500	1.031	1.139	0.977	1.194
43994	SYCAN_21	500	1.031	1.139	0.977	1.194
43995	SYCAN_22	500	1.031	1.139	0.977	1.194
47844	BIGLWCYN	230	0.979	1.082	0.927	1.133
434590	KEE_RIV_OWN	230	0.979	1.082	0.927	1.133

APPENDIX 2 - EXCERPT FROM WECC TPL-001-WECC-CRT-3 SYSTEM PERFORMANCE REGIONAL CRITERION

NERC/WECC Categories	Transient Voltage Dip Standard	Minimum Transient Frequency Standard	Post Transient Voltage Deviation Standard
P0	Nothing in addition to NERC		
P1 – P7	Following fault clearing, the voltage shall recover to 80% of the pre-contingency voltage within 20 seconds of the initiating event for all P1 through P7 events, for each applicable BES bus serving load. Following fault clearing and voltage recovery above 80%, voltage at each applicable BES bus serving load shall neither dip below 70% of pre-contingency voltage for more than 30 cycles nor remain below 80% of pre-contingency voltage for more than two seconds, for all P1 through P7 events.	No criteria.	Not to exceed 8% at any load bus for P1.

APPENDIX 3 – CONTINGENCY LIST

Table 3-1 provides a list of key bulk system contingencies to be simulated. In addition, zones 401 (Portland), 402 (Western Oregon), 403 (Central Oregon) and 404 (Lower Columbian Basin) will be simulated for all voltage levels above 200kV and 115kV contingencies in zones 401 (Portland), 450-455 (PGE contingencies) and 489 (PAC: PTLD) will be simulated. BPA and PGE provided a list of all P1, P2, P4 and P7 contingencies in their system that will be simulated, which are provided in Tables 3-2 and 3-3.

Table 3-1 Contingencies for Power Flow & Post-Transient Analysis

No	Contingency	Power Flow (PF) or Post-Transient Power Flow (PT)
1	P1.2_ALLSTON-KEELER_500	PF
2	P1.2_ALLSTON-NAPAVINE_500	PF
3	P1.2_ALLSTON-PAUL_500	PF
4	P1.2_ASHE-HANFORD_500	PF
5	P1.2_ASHE-LOWMON_500	PF
6	P1.2_ASHE-SLATT_500	PF
7	P1.2_Alvey-Dixnvile_500	PF
8	P1.2_Alvey-Marion_500	PF
9	P1.2_Ashe-Marion_500	PF
10	P1.2_BIGEDDY-CELILO1_500	PF
11	P1.2_BIGEDDY-CELILO2_500	PF
12	P1.2_BIGEDDY-JOHNDAY_500_1	PF
13	P1.2_BIGEDDY-JOHNDAY_500_2	PF
14	P1.2_BIGEDDY-KNIGHT_500	PF
15	P1.2_BIGEDDY-OSTRNDER_500	PF
16	P1.2_BUCKLEY-GRIZZLY_500	PF
17	P1.2_BUCKLEY-MARION_500	PF
18	P1.2_BUCKLEY-SLATT_500	PF
19	P1.2_BellBPA-Coulee_500	PF
20	P1.2_Burns-SummerLake_500	PF
21	P1.2_CELILO1-CELILO2_500	PF
22	P1.2_CHIEFJO-COULEE_500	PF
23	P1.2_CHIEFJO-MONROE_500	PF
24	P1.2_CHIEFJO-SICKLER_500	PF
25	P1.2_COULEE-HANFORD_500	PF
26	P1.2_COYOTE-MCNARY_500	PF
27	P1.2_COYOTE-SLATT_500	PF
28	P1.2_Chief JO-CHJ PH6_500	PF
29	P1.2_ChiefJO-CHJPH5_500	PF
30	P1.2_Coulee-Coulee19_500	PF
31	P1.2_Coulee-Coulee20_500	PF
32	P1.2_Coulee-Coulee21_500	PF
33	P1.2_Coulee-Coulee22_500	PF

No	Contingency	Power Flow (PF) or Post-Transient Power Flow (PT)
34	P1.2_Coulee-Coulee23_500	PF
35	P1.2_Coulee-Coulee24_500	PF
36	P1.2_Coulee-Schultz1_500	PF
37	P1.2_Coulee-Schultz2_500	PF
38	P1.2_Echolake-Schultz_500	PF
39	P1.2_GRASSLND-SLATT_500	PF
40	P1.2_Grizzly-JohnDay1_500	PF
41	P1.2_Grizzly-JohnDay2_500	PF
42	P1.2_HANFORD-LOWMON_500	PF
43	P1.2_HANFORD-VANTAGE_500	PF
44	P1.2_HANFORD-WAUTOMA_500	PF
45	P1.2_HANFORD-WAUTOMA_500	PF
46	P1.2_HERMCALP-MCNARY_500	PF
47	P1.2_JOHNDAY-MARION_500	PF
48	P1.2_JOHNDAY-ROCKCK_500	PF
49	P1.2_JOHNDAY-SLATT_500	PF
50	P1.2_JohnDay-JDAPH1_500	PF
51	P1.2_JohnDay-JDAPH2_500	PF
52	P1.2_JohnDay-JDAPH3_500	PF
53	P1.2_JohnDay-JDAPH4_500	PF
54	P1.2_KEELER-PEARL_500	PF
55	P1.2_KNIGHT-WAUTOMA_500	PF
56	P1.2_LANE-MARION_500	PF
57	P1.2_MAPLE VL-ROCKY RH_345	PF
58	P1.2_MARION-PEARL_500	PF
59	P1.2_MARION-SANTIAM_500	PF
60	P1.2_MCNARY-JOHNDAY_500	PF
61	P1.2_MCNARY-ROSS_345	PF
62	P1.2_OSTRNDER-KNIGHT_500	PF
63	P1.2_OSTRNDER-PEARL_500	PF
64	P1.2_OSTRNDER-TROUTDAL_500	PF
65	P1.2_RAVER-SCHULTZ_500	PF
66	P1.2_RAVER-SCHULTZ_500	PF
67	P1.2_ROCKCK-WAUTOMA_500	PF
68	P1.2_Raver-Schultz_500	PF
69	P1.2_SCHULTZ-SICKLER_500	PF
70	P1.2_SCHULTZ-VANTAGE_500	PF
71	P1.2_SCHULTZ-WAUTOMA_500	PF
72	P1.2_SamsVLY-Meridian_500	PF
73	P1.3_ALLSTON 500 to ALLSTN E 230 No_2	PF
74	P1.3_ALLSTON 500 to ALLSTN W 230 No_1	PF
75	P1.3_ALVEY 500 to ALVEY 230 No_5	PF

No	Contingency	Power Flow (PF) or Post-Transient Power Flow (PT)
76	P1.3_ASHE 230 to ASHE F 230 No_1	PF
77	P1.3_BIG EDDY 500 to BIGEDDY1 230 No_2	PF
78	P1.3_BIG EDDY 500 to BIGEDDY3 230 No_5	PF
79	P1.3_CHIEF J3 345 to CHIEF J1 230 No_1	PF
80	P1.3_CHIEF J4 345 to CHIEF J2 230 No_2	PF
81	P1.3_CHIEF JO 500 to CHIEF J2 230 No_3	PF
82	P1.3_COULEE 300 to COULEES2 230 No_1	PF
83	P1.3_COULEE 500 to COULEES2 230 No_1	PF
84	P1.3_JOHN DAY 500 to JOHN DAY 230 No_1	PF
85	P1.3_KEELER 500 to KEELER W 230 No_2	PF
86	P1.3_LANE 500 to LANE 2 230 No_3	PF
87	P1.3_MCNARY 345 to MCNRY S3 230 No_8	PF
88	P1.3_MCNARY 500 to MCNRY S1 230 No_1	PF
89	P1.3_MCNARY 500 to MCNRY S2 230 No_2	PF
90	P1.3_OSTRNDER 500 to OSTRNDER 230 No_1	PF
91	P1.3_PEARL 500 to PEARL E 230 No_1	PF
92	P1.3_PEARL 500 to PEARL W 230 No_2	PF
93	P1.3_ROCK CK 500 to ROCK CK 230 No_1	PF
94	P1.3_ROCKY RH 345 to ROCKYRH2 230 No_1	PF
95	P1.3_ROSS 230 to ROSS 345 No_4	PF
96	P1.3_SANTIAM 500 to SANTIAM EAST 230 No_4	PF
97	P1.3_SICKLER 500 to SICKLER TX 230 No_1	PF
98	P1.3_SLATT 500 to SLATT 230 No_1	PF
99	P1.3_TROUTDAL 500 to TROUTD W 230 No_8	PF
100	P1.3_VANTAGE 500 to VANTAGEN 230 No_2	PF
101	P1.3_VANTAGE 500 to VANTAGES 230 No_1	PF
102	P1.5_CRTP-VSC-HVDC Outage	PF
103	P1.5_PDCI-NS-monopole Outage	PT
104	P7.1_Malin - Round Mountain 500kV #1 and #2 Lines	PT
105	P7.2_PDCI bi-pole Outage (w/ RAS)	PT
106	Extreme_Palo Verde Generation – Trip Two Units (w/ RAS)†	PT

† NERC Extreme Event

Table 3-2 Contingencies for Power Flow & Post-Transient Analysis, BPA List

No	Contingency	Power Flow (PF) or Post-Transient Power Flow (PT)
1	P2-2 BUS Alcoa 115kV	PF
2	P2-2 BUS Allston East 230kV	PF
3	P2-2 BUS Allston West 230kV	PF
4	P2-2 BUS Carlton 115kV	PF
5	P2-2 BUS Carlton 230kV	PF
6	P2-2 BUS Chehalis 115kV	PF
7	P2-2 BUS Chehalis 230kV	PF
8	P2-2 BUS Driscoll 115kV	PF
9	P2-2 BUS Driscoll 230kV	PF
10	P2-2 BUS Forest Grove 115kV	PF
11	P2-2 BUS Keeler East 115kV	PF
12	P2-2 BUS Keeler East 230kV	PF
13	P2-2 BUS Keeler West 115kV	PF
14	P2-2 BUS Keeler West 230kV	PF
15	P2-2 BUS LongeviewS 230kV	PF
16	P2-2 BUS LongviewM 230kV	PF
17	P2-2 BUS McMinneville 115kV	PF
18	P2-2 BUS N. Bonneville Annex 115kV	PF
19	P2-2 BUS N.Bonneville East 230kV	PF
20	P2-2 BUS N.Bonneville West 230kV	PF
21	P2-2 BUS Naselle 115kV	PF
22	P2-2 BUS Oregon City 115kV	PF
23	P2-2 BUS Pearl East 230kV	PF
24	P2-2 BUS Pearl West 230kV	PF
25	P2-2 BUS PGE St. Helens 115kV	PF
26	P2-2 BUS Ross 115kV	PF
27	P2-2 BUS Ross East 230kV	PF
28	P2-2 BUS Sifton 115kV	PF
29	P2-2 BUS St. Johns 115kV	PF
30	P2-2 BUS Troutdale East 230kV	PF
31	P2-2 BUS Troutdale West 230kV	PF
32	P2-2 BUS_Big Eddy 115	PF
33	P2-2 BUS_Big Eddy 230 Sect 1	PF
34	P2-2 BUS_Big Eddy 230 Sect 2	PF
35	P2-2 BUS_Big Eddy 230 Sect 3 & 4	PF
36	P2-2 BUS_Bonneville PH 115	PF
37	P2-2 BUS_Chenoweth 115	PF
38	P2-2 BUS_Discovery NW 115	PF
39	P2-2 BUS_Hood River 115	PF
40	P2-2 BUS_N Camas 115	PF
41	P2-2 BUS_The Dalles 115	PF

No	Contingency	Power Flow (PF) or Post-Transient Power Flow (PT)
42	P2-2 Trojan East 230kV	PF
43	P2-2 Trojan West 230kV	PF
44	P2-3 Harborton V242 230kV	PF
45	P2-3 Horizon V112 230kV	PF
46	P2-3 Horizon V212 230kV	PF
47	P2-3 Murrayhill V312 230kV	PF
48	P2-4_P4-6 BSB Keeler 115kV	PF
49	P2-4_P4-6 BSB Keeler 230kV	PF
50	P2-4_P4-6 BSB Longview 115kV	PF
51	P2-4_P4-6 BSB Longview 230kV	PF
52	P2-4_P4-6 BSB N.Bonneville 230kV	PF
53	P2-4_P4-6 BSB Pearl 230kV	PF
54	P2-4_P4-6 BSB Ross 230kV	PF
55	P2-4_P4-6 BSB Troutdale 230kV	PF
56	P4-2 BKF 4194 John Day-Big Eddy #1/RockCk-John Day 500 kV	PF
57	P4-2 BKF 4202 Big Eddy-John Day #2/Ostrander 500 kV	PF
58	P4-2 BKF 4205 Big Eddy-Ostrander 500 kV/Celilo #1 500 kV	PF
59	P4-2 BKF 4209 Big Eddy-Knight & Big Eddy 500/230 #5	PF
60	P4-2 BKF 4212 Big Eddy 500/230 #5/Celilo #1 500 kV	PF
61	P4-2 BKF 4365 Marion-Lane 500kV (+Marion S Bus Shunts)	PF
62	P4-2 BKF 4368 Marion-John Day & Marion-Lane 500	PF
63	P4-2 BKF 4374 Marion-Alvey 500kV (+Marion S Bus Shunts)	PF
64	P4-2 BKF 4377 Marion-Ashe/Alvey 500kV	PF
65	P4-2 BKF 4383 Marion-Santiam 500kV (+Marion S Bus Shunts)	PF
66	P4-2 BKF 4386 Marion-Buckley/Santiam 500kV	PF
67	P4-2 BKF 4394 Keeler-Allston & Pearl-Keeler (+ Keeler caps) 500kV	PF
68	P4-2 BKF 4432 Ostrander-Troutdale (+ Ostrander W Bus caps) 500kV	PF
69	P4-2 BKF 4433 Ostrander-Troutdale 500 kV (+Ostrander W Bus Caps)	PF
70	P4-2 BKF 4439 Ostrander-Knight (+ Ostrander E Bus reactors) 500 kV	PF
71	P4-2 BKF 4442 Ostrander-McLoughlin 230 kV / Knight 500kV	PF
72	P4-2 BKF 4445 Ostrander-McLoughlin 230 kV (+Ostrander W Bus Caps)	PF
73	P4-2 BKF 4448 Ostrander-Big Eddy (+ Ostrander E Bus reactors) 500kV	PF
74	P4-2 BKF 4450 Ostrander-Pearl 500 kV / Big Eddy - Ostrander 500 kV	PF
75	P4-2 BKF 4475 Pearl-Marion 500kV & Pearl 500/230 TX 2	PF
76	P4-2 BKF 4510 Pearl-Marion/Pearl TX #1 (+ Pearl E Bus caps) 500kV	PF

No	Contingency	Power Flow (PF) or Post-Transient Power Flow (PT)
77	P4-2 BKF 4860 Big Eddy-Knight 500 kV/Celilo #2 500 kV	PF
78	P4-2 BKF 4867 Big Eddy 500/230 #2/Celilo #1 500 kV	PF
79	P4-2 BKF 4870 Big Eddy - John Day #1 & Big Eddy 500/230 #2	PF
80	P4-2 BKF 4872 John Day-Big Eddy #1/Celilo #2 500 kV	PF
81	P4-2 BKF 4946 Pearl - Marion 500 kV (+Marion S Bus Shunts)	PF
82	P4-2 BKF 5134 Ostrander-Pearl/Ostrander W Bus Caps 500kV	PF
83	P4-2 BKF 5139 Ostrander - Troutdale (+ Ostrander E Bus reactors) 500kV	PF
84	P4-2 BKF 5452 Pearl-Ostrander/Pearl TX #1 (+ Pearl E Bus caps) 500kV	PF
85	P4-2 BKF 5455 Pearl-Ostrander/Pearl #2 500/230kV	PF
86	P4-2 BKF Alcoa B1893 115 kV	PF
87	P4-2 BKF Alcoa B224 115 kV	PF
88	P4-2 BKF Alcoa B234 115 kV	PF
89	P4-2 BKF Alcoa B236 115 kV	PF
90	P4-2 BKF Alcoa B238 115 kV	PF
91	P4-2 BKF Cherry Grove B1 115 kV	PF
92	P4-2 BKF Cherry Grove B2 115 kV	PF
93	P4-2 BKF Cherry Grove B3 115 kV	PF
94	P4-2 BKF Cherry Grove B4 115 kV	PF
95	P4-2 BKF Hazeldell PCB 1 BF	PF
96	P4-2 BKF Hazeldell PCB 2	PF
97	P4-2 BKF Hazeldell PCB 3	PF
98	P4-2 BKF Hazeldell PCB 4	PF
99	P4-2 BKF North Camas PCB 1	PF
100	P4-2 BKF North Camas PCB 2	PF
101	P4-2 BKF North Camas PCB 3	PF
102	P4-2 BKF North Camas PCB 4	PF
103	P4-2 BKF Runyan PCB 1	PF
104	P4-2 BKF Runyan PCB 3	PF
105	P4-2 BKF Runyan PCB 5	PF
106	P4-2 BKF Troutdale 2P112	PF
107	P4-2 BKF Troutdale 2P113 (BF)	PF
108	P4-2 BKF Troutdale 2P114 (BF)	PF
109	P4-2 BKF_Big Eddy B1696 (The Dalles) 115	PF
110	P4-2 BKF_Bonneville PH (Alcoa) 115	PF
111	P4-2 BKF_Bonneville PH (Hood River) 115	PF
112	P4-2 BKF_Bonneville PH (N Camas) 115	PF
113	P4-2 BKF_Hood River B1680 (Bonneville PH) 115	PF
114	P4-2 BKF_The Dalles (Big Eddy) 115	PF
115	P4-2 Pearl 4280 BPA 500kV	PF
116	P4-6 BSB Longview 230kV	PF
117	P4-6 BSB N.Bonneville 230kV	PF

No	Contingency	Power Flow (PF) or Post-Transient Power Flow (PT)
118	P4-6 BSB Ross 230kV	PF
119	P7 Harborton-Rivergate 230 kV + Harborton-Rivergate 115kV	PF
120	P7 Keeler-St. Marys 230 kV + Harborton-Evergreen 230 kV	PF
121	P7 Trojan-St. Marys/Harborton #1 230 kV + Trojan-Harborton #2 230 kV	PF
122	P7-1 CTR Allston-Trojan #1 and #2 230kV	PF
123	P7-1 CTR Ashe-Marion 2 500 AND Ashe-Slatt 1 500	PF
124	P7-1 CTR Ashe-Marion 2 500 AND Buckley-Marion 1 500	PF
125	P7-1 CTR Ashe-Marion 2 500 AND Slatt-Buckley 1 500	PF
126	P7-1 CTR Big Eddy-Troutdale 1 AND Big Eddy-Chemawa 1 230kV	PF
127	P7-1 CTR BONN PH 2-NBONN 4 230kV AND BONN PH 2-NBONN 4 230kV	PF
128	P7-1 CTR BONN PH-Alcoa 1&2 AND BONN PH-N Camas 1 115kV	PF
129	P7-1 CTR Carlton-McMinnville 115kV AND Forest Grove-McMinnville 115kV	PF
130	P7-1 CTR Carlton-Tillamook 230kV AND Forest Grove-Tillamook 115kV	PF
131	P7-1 CTR Chemawa-Salem 1 230kV AND Chemawa-Salem 2 115kV	PF
132	P7-1 CTR Cherry-Pioneer & 119th 115 kV	PF
133	P7-1 CTR Longview-Allston #1 and #2 230kV	PF
134	P7-1 CTR Longview-Allston #3 230kV and #4 115kV	PF
135	P7-1 CTR N. Sifton-Ast/Sifton-Lacamas 115 kV	PF
136	P7-1 CTR N.Bonneville-Ross #2/N.Bonneville-Troutdale #2 230kV	PF
137	P7-1 CTR Naselle-Tarlett 1 115kV AND Naselle-Tarlett 2 115kV	PF
138	P7-1 CTR North Camas-Sifton 1 115kV AND BONN PH 1-North Camas 1 115kV	PF
139	P7-1 CTR PAC Troutdale-BPA Troutdale #1 and #2 230kV	PF
140	P7-1 CTR PAC Troutdale-Gresham #1 & #2 230kV	PF
141	P7-1 CTR PGE Harborton-Evergreen 230kV & Harborton-St Marys 230kV	PF
142	P7-1 CTR PGE Keeler-StMarys/Keeler-Rivergate 230kV	PF
143	P7-1 CTR PGE Murrayhill - Sherwood 230 kV (1 & 2)	PF
144	P7-1 CTR Ross-Rivergate 230 kV / Ross-St. John's 230	PF
145	P7-1 CTR Ross-Sifton 115 and Bonneville-Alcoa 115	PF
146	P7-1 CTR Runyan-Ast & Troutdale DBL CKT 115	PF
147	P7-1 CTR Sifton-Ast/Sifton-Lacamas 115 kV	PF
148	P7-1 CTR Sifton-Silicon DBL CKT 115	PF
149	P7-1 CTR St Johns-Keeler 2 115kV AND St Johns-St Helens 1 115kV	PF
150	P7-1 CTR_Bonneville PH - North Camas #1 115 / Bonneville PH - Alcoa 1 & 2 115	PF

No	Contingency	Power Flow (PF) or Post-Transient Power Flow (PT)
151	PX ADJ BIG EDDY-PARKDALE-TROUTDALE,BIG EDDY-CHEMAWA 230	PF
152	Extreme Event: PX ADJ Ostrander-Pearl 500kV / Big Eddy-Chemawa 230kV	PF

Table 3-3 Contingencies for Power Flow & Post-Transient Analysis, PGE List

No	Contingency	Power Flow (PF) or Post-Transient Power Flow (PT)
1	P1-1: Beaver #1	PT
2	P1-1: Beaver #2	PT
3	P1-1: Beaver #3	PT
4	P1-1: Beaver #4	PT
5	P1-1: Beaver #5	PT
6	P1-1: Beaver #6	PT
7	P1-1: Beaver #7	PT
8	P1-1: Beaver #8	PT
9	P1-1: Biglow Canyon #1	PT
10	P1-1: Biglow Canyon #2	PT
11	P1-1: Biglow Canyon #3	PT
12	P1-1: Carty Gas Turbine	PT
13	P1-1: Carty Steam Turbine	PT
14	P1-1: Covanta	PT
15	P1-1: Coyote Gas Turbine	PT
16	P1-1: Coyote Steam Turbine	PT
17	P1-1: Faraday #6	PT
18	P1-1: Faraday #7	PT
19	P1-1: Faraday #8	PT
20	P1-1: Merwin PACW #1	PT
21	P1-1: Merwin PACW #2	PT
22	P1-1: Merwin PACW #3	PT
23	P1-1: Mint Farm PSE Gas Turbine	PT
24	P1-1: Mint Farm PSE Steam Turbine	PT
25	P1-1: Mullan #1	PT
26	P1-1: Mullan #2	PT
27	P1-1: North Fork #1	PT
28	P1-1: North Fork #2	PT
29	P1-1: Oak Grove #1	PT
30	P1-1: Oak Grove #2	PT
31	P1-1: Parkdale BPA	PT
32	P1-1: Pelton #1	PT
33	P1-1: Pelton #2	PT
34	P1-1: Pelton #3	PT

No	Contingency	Power Flow (PF) or Post-Transient Power Flow (PT)
35	P1-1: Pelton Re-Reg PACW	PT
36	P1-1: Port Westward 2 BESS	PT
37	P1-1: Port Westward 2 Gen. #1	PT
38	P1-1: Port Westward 2 Gen. #10	PT
39	P1-1: Port Westward 2 Gen. #11	PT
40	P1-1: Port Westward 2 Gen. #12	PT
41	P1-1: Port Westward 2 Gen. #2	PT
42	P1-1: Port Westward 2 Gen. #3	PT
43	P1-1: Port Westward 2 Gen. #4	PT
44	P1-1: Port Westward 2 Gen. #5	PT
45	P1-1: Port Westward 2 Gen. #6	PT
46	P1-1: Port Westward 2 Gen. #7	PT
47	P1-1: Port Westward 2 Gen. #8	PT
48	P1-1: Port Westward 2 Gen. #9	PT
49	P1-1: Port Westward Gas Turbine	PT
50	P1-1: Port Westward Steam Turbine	PT
51	P1-1: Portland Bull Run #1	PT
52	P1-1: Portland Bull Run #2	PT
53	P1-1: River Mill #1	PT
54	P1-1: River Mill #2	PT
55	P1-1: River Mill #3	PT
56	P1-1: River Mill #4	PT
57	P1-1: River Mill #5	PT
58	P1-1: River Road CPU	PT
59	P1-1: Round Butte #1	PT
60	P1-1: Round Butte #2	PT
61	P1-1: Round Butte #3	PT
62	P1-1: Sullivan	PT
63	P1-1: Swift1 PACW #1	PT
64	P1-1: Swift1 PACW #2	PT
65	P1-1: Swift1 PACW #3	PT
66	P1-1: Swift2 PACW #1	PT
67	P1-1: Swift2 PACW #2	PT
68	P1-1: Wauna CLPUD #1	PT
69	P1-1: Yale PACW #1	PT
70	P1-1: Yale PACW #2	PT
71	P1-2: Albany BPA-Hazelwood PACW 115kV	PF
72	P1-2: Albany BPA-Salem BPA #1 115kV	PF
73	P1-2: Albany BPA-Salem BPA #2 115kV	PF
74	P1-2: Albany BPA-Santiam BPA 230kV	PF
75	P1-2: Albina PACW-Curtis 115kV	PF
76	P1-2: Albina PACW-Delaware 115kV	PF

No	Contingency	Power Flow (PF) or Post-Transient Power Flow (PT)
77	P1-2: Albina PACW-Knott PACW 115kV	PF
78	P1-2: Albina PACW-Knott PACW-St Johns BPA 115kV	PF
79	P1-2: Alcoa BPA-River Road CPU 115kV	PF
80	P1-2: Alcoa BPA-Ross BPA 230kV	PF
81	P1-2: Alder-Harrison 115kV	PF
82	P1-2: Alder-Tabor 115kV	PF
83	P1-2: Allston BPA-Clatsop BPA-Driscoll BPA 230kV	PF
84	P1-2: Allston BPA-Driscoll BPA #1 230kV	PF
85	P1-2: Allston BPA-Keeler BPA 500kV	PF
86	P1-2: Allston BPA-Longview BPA #1 230kV	PF
87	P1-2: Allston BPA-Longview BPA #2 230kV	PF
88	P1-2: Allston BPA-Longview BPA #3 230kV	PF
89	P1-2: Allston BPA-Longview BPA #4 115kV	PF
90	P1-2: Allston BPA-Napavine BPA 500kV	PF
91	P1-2: Allston BPA-Paul BPA 500kV	PF
92	P1-2: Allston BPA-St Helens 115kV	PF
93	P1-2: Allston BPA-Trojan #1 230kV	PF
94	P1-2: Allston BPA-Trojan #2 230kV	PF
95	P1-2: Alvey BPA-Dixonville PACW 230kV	PF
96	P1-2: Alvey BPA-Dixonville PACW 500kV	PF
97	P1-2: Alvey BPA-Lane BPA 230kV	PF
98	P1-2: Alvey BPA-Marion BPA 500kV	PF
99	P1-2: Alvey BPA-Santiam BPA 230kV	PF
100	P1-2: Arrowhead-Sherwood 115kV	PF
101	P1-2: Arrowhead-Wilsonville 115kV	PF
102	P1-2: Ashe BPA-Hanford BPA 500kV	PF
103	P1-2: Ashe BPA-Lower Monumental BPA 500kV	PF
104	P1-2: Ashe BPA-Marion BPA 500kV	PF
105	P1-2: Ashe BPA-Slatt BPA 500kV	PF
106	P1-2: Astoria PACW-Driscoll BPA 115kV	PF
107	P1-2: Astoria PACW-Lewis & Clark PACW-Tillamook BPA 115kV	PF
108	P1-2: Astoria PACW-Youngs Bay PACW 115kV	PF
109	P1-2: Banks-Century 57kV	PF
110	P1-2: Banks-Cornelius 57kV	PF
111	P1-2: Banks-North Plains 57kV	PF
112	P1-2: Beaver-Port Westward 230kV	PF
113	P1-2: Beaverton-Denny 115kV	PF
114	P1-2: Beaverton-Murrayhill 115kV	PF
115	P1-2: Beaverton-Progress 115kV	PF
116	P1-2: Beaverton-Tektronix 115kV	PF
117	P1-2: Bell-Gresham 115kV	PF
118	P1-2: Bell-Sellwood 115kV	PF

No	Contingency	Power Flow (PF) or Post-Transient Power Flow (PT)
119	P1-2: Bethel-Culver 115kV	PF
120	P1-2: Bethel-Elma 57kV	PF
121	P1-2: Bethel-Market 115kV	PF
122	P1-2: Bethel-McLoughlin 230kV	PF
123	P1-2: Bethel-Parrish Gap PACW 230kV	PF
124	P1-2: Bethel-Round Butte 230kV	PF
125	P1-2: Bethel-Salem 57kV	PF
126	P1-2: Bethel-Santiam BPA 230kV	PF
127	P1-2: Bethel-Silverton 57kV	PF
128	P1-2: Big Eddy BPA-Chemawa BPA 230kV	PF
129	P1-2: Big Eddy BPA-John Day BPA #1 500kV	PF
130	P1-2: Big Eddy BPA-John Day BPA #2 500kV	PF
131	P1-2: Big Eddy BPA-Knight BPA 500kV	PF
132	P1-2: Big Eddy BPA-McLoughlin 230kV	PF
133	P1-2: Big Eddy BPA-Ostrander BPA 500kV	PF
134	P1-2: Big Eddy BPA-Redmond BPA 230kV	PF
135	P1-2: Big Eddy BPA-Troutdale BPA 230kV	PF
136	P1-2: Biglow Canyon-Golden Hills Avangrid 230kV	PF
137	P1-2: Biglow Canyon-John Day BPA 230kV	PF
138	P1-2: Blue Lake-Fairview 115kV	PF
139	P1-2: Blue Lake-Glendoveer 115kV	PF
140	P1-2: Blue Lake-Gresham 230kV	PF
141	P1-2: Blue Lake-Kelly Butte 115kV	PF
142	P1-2: Blue Lake-McGill 115kV	PF
143	P1-2: Blue Lake-Tabor 115kV	PF
144	P1-2: Blue Lake-Troutdale BPA #1 230kV	PF
145	P1-2: Blue Lake-Troutdale BPA #2 230kV	PF
146	P1-2: Boring-Dunns Corner 57kV	PF
147	P1-2: Boring-Faraday 57kV	PF
148	P1-2: Boring-Hogan-Lents 57kV	PF
149	P1-2: Boring-River Mill 57kV	PF
150	P1-2: Boyer PACW-Devils Lake PACW #2 115kV	PF
151	P1-2: Boyer PACW-Grand Ronde 115kV	PF
152	P1-2: Boyer PACW-Tillamook BPA 115kV	PF
153	P1-2: Brightwood-Rhododendron 57kV	PF
154	P1-2: Brookwood-Shute 115kV	PF
155	P1-2: Brookwood-St Marys 115kV	PF
156	P1-2: Buckley BPA-Grizzly BPA 500kV	PF
157	P1-2: Buckley BPA-Marion BPA 500kV	PF
158	P1-2: Buckley BPA-Slatt BPA 500kV	PF
159	P1-2: Butler-Orenco 115kV	PF
160	P1-2: Butler-St Marys 115kV	PF

No	Contingency	Power Flow (PF) or Post-Transient Power Flow (PT)
161	P1-2: Butler-Sunset #1 115kV	PF
162	P1-2: Butler-Sunset #2 115kV	PF
163	P1-2: Canemah-Carver 115kV	PF
164	P1-2: Canemah-Leland 57kV	PF
165	P1-2: Canemah-McLoughlin 115kV	PF
166	P1-2: Canemah-Rosemont 115kV	PF
167	P1-2: Canemah-Sullivan #1 57kV	PF
168	P1-2: Canemah-Sullivan #2 57kV	PF
169	P1-2: Canemah-Sullivan 115kV	PF
170	P1-2: Canyon-E 115kV	PF
171	P1-2: Canyon-Glencullen 115kV	PF
172	P1-2: Canyon-Urban 115kV	PF
173	P1-2: Canyon-West Portland 115kV	PF
174	P1-2: Captain Jack BPA-Malin BPA #1 500kV	PF
175	P1-2: Captain Jack BPA-Malin PACW #2 500kV	PF
176	P1-2: Captain Jack BPA-Olinda WAPA 500kV	PF
177	P1-2: Captain Jack BPA-Ponderosa BPA-Grizzly BPA 500kV	PF
178	P1-2: Captain Jack BPA-Snowgoose PACW 500kV	PF
179	P1-2: Cardwell BPA-Cowlitz BPA 115kV	PF
180	P1-2: Cardwell BPA-Merwin PACW 115kV	PF
181	P1-2: Carlton BPA-McMinnville BPA #1 115kV	PF
182	P1-2: Carlton BPA-Sherwood 230kV	PF
183	P1-2: Carlton BPA-Tillamook BPA 230kV	PF
184	P1-2: Carty-Grassland 500kV	PF
185	P1-2: Carver-Clackamas 115kV	PF
186	P1-2: Carver-Gresham #1 230kV	PF
187	P1-2: Carver-Gresham #3 115kV	PF
188	P1-2: Carver-Hogan South 115kV	PF
189	P1-2: Carver-McLoughlin #1 230kV	PF
190	P1-2: Carver-McLoughlin #2 230kV	PF
191	P1-2: Carver-Pleasant Valley 115kV	PF
192	P1-2: Carver-Sellwood 115kV	PF
193	P1-2: Carver-Town Center 115kV	PF
194	P1-2: Central Ferry BPA-Mullan 230kV	PF
195	P1-2: Century-Helvetia 115kV	PF
196	P1-2: Century-North Plains 57kV	PF
197	P1-2: Century-Orenco 115kV	PF
198	P1-2: Century-West Union 115kV	PF
199	P1-2: Chemawa BPA-Claxtar 57kV	PF
200	P1-2: Chemawa BPA-Dayton 57kV	PF
201	P1-2: Chemawa BPA-Indian 115kV	PF
202	P1-2: Chemawa BPA-Market 115kV	PF

No	Contingency	Power Flow (PF) or Post-Transient Power Flow (PT)
203	P1-2: Chemawa BPA-McClain 57kV	PF
204	P1-2: Chemawa BPA-Oregon City BPA 115kV	PF
205	P1-2: Chemawa BPA-Salem 57kV	PF
206	P1-2: Chemawa BPA-Salem Alumina BPA 115kV	PF
207	P1-2: Chemawa BPA-Salem BPA #1 230kV	PF
208	P1-2: Chemawa BPA-Salem BPA #2 115kV	PF
209	P1-2: Chemawa BPA-Santiam BPA 230kV	PF
210	P1-2: Chemawa BPA-St Louis 57kV	PF
211	P1-2: Chemawa BPA-Waconda 57kV	PF
212	P1-2: Chemawa BPA-Wallace 57kV	PF
213	P1-2: Cherry Grove CPU-Hazel Dell CPU 115kV	PF
214	P1-2: Cherry Grove CPU-View CPU 115kV	PF
215	P1-2: Chiloquin PACW-LaPine BPA 230kV	PF
216	P1-2: Columbia PACW-Killingsworth PACW 69kV	PF
217	P1-2: Cornelius-Forest Grove BPA 115kV	PF
218	P1-2: Cornelius-Orenco #1 57kV	PF
219	P1-2: Cornelius-Orenco #2 57kV	PF
220	P1-2: Cornelius-Scoggins 57kV	PF
221	P1-2: Cornelius-Yamhill 57kV	PF
222	P1-2: Corral PACW-Ochoco PACW #1 230kV	PF
223	P1-2: Corral PACW-Ochoco PACW #2 230kV	PF
224	P1-2: Corral PACW-Ponderosa BPA #1 230kV	PF
225	P1-2: Corral PACW-Ponderosa BPA #2 230kV	PF
226	P1-2: Cove PACW-Round Butte #1 230kV	PF
227	P1-2: Cove PACW-Round Butte #2 230kV	PF
228	P1-2: Cowlitz BPA-Longview BPA 115kV	PF
229	P1-2: Coyote BPA-McNary BPA 500kV	PF
230	P1-2: Coyote BPA-Slatt BPA 500kV	PF
231	P1-2: Culver-Mill Creek 115kV	PF
232	P1-2: Curtis-Delaware 115kV	PF
233	P1-2: Curtis-Northern 115kV	PF
234	P1-2: Curtis-Portsmouth 115kV	PF
235	P1-2: Curtis-Rivergate 115kV	PF
236	P1-2: Dayton-McMinnville BPA-Newberg 115kV	PF
237	P1-2: Dayton-Sheridan 57kV	PF
238	P1-2: Dayton-Wallace 57kV	PF
239	P1-2: Dayton-Yamhill 57kV	PF
240	P1-2: Detroit BPA-Santiam BPA 230kV	PF
241	P1-2: Driscoll BPA-Naselle BPA 115kV	PF
242	P1-2: Dunns Corner-Brightwood 57kV	PF
243	P1-2: Dunns Corner-Hogan 57kV	PF
244	P1-2: Dunns Corner-Orient 57kV	PF

No	Contingency	Power Flow (PF) or Post-Transient Power Flow (PT)
245	P1-2: Dunns Corner-Portland Hydro Project 57kV	PF
246	P1-2: Dunns Corner-Welches 57kV	PF
247	P1-2: E-Bethany 115kV	PF
248	P1-2: E-St Marys 115kV	PF
249	P1-2: Evergreen-Harborton 230kV	PF
250	P1-2: Evergreen-Helvetia 115kV	PF
251	P1-2: Evergreen-Horizon 230kV	PF
252	P1-2: Evergreen-Rock Creek 115kV	PF
253	P1-2: Evergreen-Shute 115kV	PF
254	P1-2: Evergreen-Sunset 115kV	PF
255	P1-2: E-Wacker 115kV	PF
256	P1-2: Fairview-Glisan 115kV	PF
257	P1-2: Faraday-Colton 57kV	PF
258	P1-2: Faraday-McLoughlin 115kV	PF
259	P1-2: Faraday-Molalla 57kV	PF
260	P1-2: Faraday-North Fork 115kV	PF
261	P1-2: Faraday-Oak Grove 115kV	PF
262	P1-2: Faraday-River Mill 57kV	PF
263	P1-2: Forest Grove BPA-Keeler BPA #1 115kV	PF
264	P1-2: Forest Grove BPA-Keeler BPA #2 115kV	PF
265	P1-2: Forest Grove BPA-McMinnville BPA 115kV	PF
266	P1-2: Forest Grove BPA-Tillamook BPA 115kV	PF
267	P1-2: Fry PACW-Oremet PACW 115kV	PF
268	P1-2: Fry PACW-Parrish Gap PACW 230kV	PF
269	P1-2: Glendoveer-Gresham 115kV	PF
270	P1-2: Glendoveer-Russelville PACW 115kV	PF
271	P1-2: Glendoveer-Tabor 115kV	PF
272	P1-2: Glisan-McGill 115kV	PF
273	P1-2: Glisan-Ruby 115kV	PF
274	P1-2: Grand Ronde-Salem BPA 115kV	PF
275	P1-2: Grand Ronde-Sheridan 57kV	PF
276	P1-2: Grassland-Slatt BPA 500kV	PF
277	P1-2: Gresham-Eastport 115kV	PF
278	P1-2: Gresham-Holgate 115kV	PF
279	P1-2: Gresham-Pleasant Valley 115kV	PF
280	P1-2: Gresham-Ruby 115kV	PF
281	P1-2: Gresham-Troutdale PACW 230kV #1	PF
282	P1-2: Gresham-Troutdale PACW 230kV #2	PF
283	P1-2: Grizzly BPA-John Day BPA #1 500kV	PF
284	P1-2: Grizzly BPA-John Day BPA #2 500kV	PF
285	P1-2: Grizzly BPA-Malin BPA #2 500kV	PF
286	P1-2: Grizzly BPA-Ponderosa BPA-Summer Lake BPA 500kV	PF

No	Contingency	Power Flow (PF) or Post-Transient Power Flow (PT)
287	P1-2: Grizzly BPA-Round Butte 500kV	PF
288	P1-2: Hanford BPA-Wautoma BPA #1 500kV	PF
289	P1-2: Hanford BPA-Wautoma BPA #2 500kV	PF
290	P1-2: Harborton-Kaster 115kV	PF
291	P1-2: Harborton-Kelley Point 115kV	PF
292	P1-2: Harborton-Rivergate #1 230kV	PF
293	P1-2: Harborton-Rivergate #2 115kV	PF
294	P1-2: Harborton-Scappoose 115kV	PF
295	P1-2: Harborton-St Marys 230kV	PF
296	P1-2: Harborton-Trojan #1 230kV	PF
297	P1-2: Harborton-Trojan #2 230kV	PF
298	P1-2: Harborton-Wacker 115kV	PF
299	P1-2: Harrison PACW-Holgate 115kV	PF
300	P1-2: Harrison PACW-Holladay PACW 115kV	PF
301	P1-2: Harrison PACW-Lincoln PACW 115kV	PF
302	P1-2: Harrison-Harrison PACW 115kV	PF
303	P1-2: Harrison-Marquam 115kV	PF
304	P1-2: Hazel Dell PACW-River Road CPU-St Johns SS PACW 115kV	PF
305	P1-2: Hillcrest-Liberty 115kV	PF
306	P1-2: Hillcrest-Mill Creek 115kV	PF
307	P1-2: Hillcrest-Oxford 115kV	PF
308	P1-2: Hogan South-McGill 115kV	PF
309	P1-2: Hogan South-Orient 57kV	PF
310	P1-2: Hogan South-Tabor 57kV	PF
311	P1-2: Holgate-Eastport 115kV	PF
312	P1-2: Holladay PACW-Knott PACW 115kV	PF
313	P1-2: Horizon-Keeler BPA #1 230kV	PF
314	P1-2: Horizon-Keeler BPA #2 230kV	PF
315	P1-2: John Day BPA-Marion BPA 500kV	PF
316	P1-2: John Day BPA-McNary BPA 500kV	PF
317	P1-2: John Day BPA-Slatt BPA 500kV	PF
318	P1-2: Jones Canyon BPA-Santiam BPA 230kV	PF
319	P1-2: Kaster-Scappoose 115kV	PF
320	P1-2: Kaster-St Helens 115kV	PF
321	P1-2: Keeler BPA-Oregon City BPA 115kV	PF
322	P1-2: Keeler BPA-Pearl BPA 500kV	PF
323	P1-2: Keeler BPA-Rivergate 230kV	PF
324	P1-2: Keeler BPA-St Johns BPA 115kV	PF
325	P1-2: Keeler BPA-St Marys 230kV	PF
326	P1-2: King City-Sherwood 115kV	PF
327	P1-2: King City-West Portland 115kV	PF
328	P1-2: Knight BPA-Ostrander BPA 500kV	PF

No	Contingency	Power Flow (PF) or Post-Transient Power Flow (PT)
329	P1-2: Knight BPA-Wautoma BPA 500kV	PF
330	P1-2: Knott PACW-Sellwood 57kV	PF
331	P1-2: Knott PACW-St Johns SS PACW 115kV	PF
332	P1-2: Knott PACW-Tabor 57kV	PF
333	P1-2: Knott PACW-Troutdale PACW 115kV	PF
334	P1-2: La Pine BPA-Pilot Butte PACW 230kV	PF
335	P1-2: Lane BPA-Marion BPA 500kV	PF
336	P1-2: Leland-Liberal 57kV	PF
337	P1-2: Leland-Molalla 57kV	PF
338	P1-2: Lents-Arleta 57kV	PF
339	P1-2: Lents-Sellwood 57kV	PF
340	P1-2: Lents-Tabor 57kV	PF
341	P1-2: Lexington BPA-Longview BPA #1 115kV	PF
342	P1-2: Lexington BPA-Longview BPA #2 230kV	PF
343	P1-2: Lexington BPA-Woodland BPA-Ross BPA 230kV	PF
344	P1-2: Liberty-Fairmount 115kV	PF
345	P1-2: Liberty-Salem BPA 115kV	PF
346	P1-2: Lincoln PACW-Marquam 115kV	PF
347	P1-2: Longview BPA-Mint Farm PSE 230kV	PF
348	P1-2: Marion BPA-Pearl BPA 500kV	PF
349	P1-2: Marion BPA-Santiam BPA 500kV	PF
350	P1-2: Market-Indian 115kV	PF
351	P1-2: Market-Oxford 115kV	PF
352	P1-2: Market-University 115kV	PF
353	P1-2: Marquam-Urban 115 kV	PF
354	P1-2: McLoughlin-Island 115kV	PF
355	P1-2: McLoughlin-Oak Grove 115kV	PF
356	P1-2: McLoughlin-Ostrander BPA 230kV	PF
357	P1-2: McLoughlin-Pearl BPA-Sherwood 230kV	PF
358	P1-2: McLoughlin-Sellwood 115kV	PF
359	P1-2: McMinnville BPA-Gormley MW&L 115kV	PF
360	P1-2: McNary BPA-Morrow Flat BPA #1 230kV	PF
361	P1-2: McNary BPA-Morrow Flat BPA #2 230kV	PF
362	P1-2: McNary BPA-Ross BPA 345kV	PF
363	P1-2: Meridian-Rosemont 115kV	PF
364	P1-2: Meridian-Tonquin 115kV	PF
365	P1-2: Meridian-Tualatin 115kV	PF
366	P1-2: Merwin PACW-Lewis River CCPD 115kV	PF
367	P1-2: Merwin PACW-View CPU 115kV	PF
368	P1-2: Merwin PACW-Yale PACW 115kV	PF
369	P1-2: Molalla-Colton 57kV	PF
370	P1-2: Molalla-Liberal 57kV	PF

No	Contingency	Power Flow (PF) or Post-Transient Power Flow (PT)
371	P1-2: Molalla-Mt Angel 57kV	PF
372	P1-2: Monitor-Mt Angel 57kV	PF
373	P1-2: Monitor-North Marion 57kV	PF
374	P1-2: Monitor-Woodburn 57kV	PF
375	P1-2: Mt Angel-Silverton 57kV	PF
376	P1-2: Murrayhill-Reedville 115kV	PF
377	P1-2: Murrayhill-Scholls Ferry 115kV	PF
378	P1-2: Murrayhill-Sherwood #1 230kV	PF
379	P1-2: Murrayhill-Sherwood #2 230kV	PF
380	P1-2: Murrayhill-St Marys 230kV	PF
381	P1-2: Napavine BPA-Paul BPA 500kV	PF
382	P1-2: Newberg-Sherwood 115kV	PF
383	P1-2: Newberg-Springbrook 115kV	PF
384	P1-2: North Bonneville BPA-North Bonneville PH1 USACE #1 230kV	PF
385	P1-2: North Bonneville BPA-North Bonneville PH2 USACE #2 230kV	PF
386	P1-2: North Bonneville BPA-North Bonneville PH3 USACE #3 230kV	PF
387	P1-2: North Bonneville BPA-North Bonneville PH4 USACE #4 230kV	PF
388	P1-2: North Bonneville BPA-Ross BPA #1 230kV	PF
389	P1-2: North Bonneville BPA-Ross BPA #2 230kV	PF
390	P1-2: North Bonneville BPA-Troutdale BPA #1 230kV	PF
391	P1-2: North Bonneville BPA-Troutdale BPA #2 230kV	PF
392	P1-2: North Marion-St Louis 57kV	PF
393	P1-2: North Marion-Sullivan 57kV	PF
394	P1-2: North Marion-Twilight 57kV	PF
395	P1-2: North Marion-Woodburn 57kV	PF
396	P1-2: Northern-Rivergate 115kV	PF
397	P1-2: Oregon City BPA-Knights Bridge CUB 57kV	PF
398	P1-2: Orenco-Roseway 115kV	PF
399	P1-2: Orenco-St Marys #1 115kV	PF
400	P1-2: Orenco-St Marys #2 115kV	PF
401	P1-2: Ostrander BPA-Pearl BPA 500kV	PF
402	P1-2: Ostrander BPA-Troutdale BPA 500kV	PF
403	P1-2: Oswego-Boones Ferry 115kV	PF
404	P1-2: Oswego-Rosemont 115kV	PF
405	P1-2: Oswego-West Portland 115kV	PF
406	P1-2: Oxford-University 115kV	PF
407	P1-2: Pearl BPA-Sherwood 230kV	PF
408	P1-2: Pelton-Round Butte 230kV	PF
409	P1-2: Pilot Butte PACW-Ponderosa BPA 230kV	PF
410	P1-2: Pilot Butte PACW-Redmond BPA 230kV	PF
411	P1-2: Port Westward-Port Westward 2 230kV	PF
412	P1-2: Port Westward-Trojan #1 230kV	PF

No	Contingency	Power Flow (PF) or Post-Transient Power Flow (PT)
413	P1-2: Port Westward-Trojan #2 230kV	PF
414	P1-2: Progress-Denny 115kV	PF
415	P1-2: Progress-West Portland 115kV	PF
416	P1-2: Redmond BPA-Redmond PACW 115kV	PF
417	P1-2: Redmond BPA-Round Butte 230kV	PF
418	P1-2: Reedville-Roseway 115kV	PF
419	P1-2: Reedville-St Marys 115kV	PF
420	P1-2: Rhododendron-Summit 57kV	PF
421	P1-2: Rivergate-Kelley Point 115kV	PF
422	P1-2: Rivergate-Oregon Steel 115kV	PF
423	P1-2: Rivergate-Portsmouth 115kV	PF
424	P1-2: Rivergate-Rivergate South 115kV	PF
425	P1-2: Rivergate-Ross BPA 230kV	PF
426	P1-2: Rock Creek BPA-Wautoma BPA 500kV	PF
427	P1-2: Rock Creek-West Union 115kV	PF
428	P1-2: Rosemont-Sullivan 115kV	PF
429	P1-2: Rosemont-Wilsonville 115kV	PF
430	P1-2: Ross BPA-St Johns BPA 230kV	PF
431	P1-2: Runyan CPU-Troutdale PACW 115kV	PF
432	P1-2: Salem BPA-Fairmount 115kV	PF
433	P1-2: Salem-McClain 57kV	PF
434	P1-2: Santiam BPA-Toledo BPA 230kV	PF
435	P1-2: Scholls Ferry-Sherwood 115kV	PF
436	P1-2: Schultz BPA-Wautoma BPA 500kV	PF
437	P1-2: Scoggins-Stimson Lumber 57kV	PF
438	P1-2: Sellwood-Island 115kV	PF
439	P1-2: Sellwood-Raleigh Hills 115kV	PF
440	P1-2: Sellwood-Town Center 115kV	PF
441	P1-2: Sellwood-Urban-West Portland 115kV	PF
442	P1-2: Sherwood-Six Corners 115kV	PF
443	P1-2: Sherwood-Springbrook 115kV	PF
444	P1-2: Sherwood-Tonquin 115kV	PF
445	P1-2: Shute-Sunset 115kV	PF
446	P1-2: Springbrook-Six Corners 115kV	PF
447	P1-2: St Helens-St Johns BPA 115kV	PF
448	P1-2: St Johns BPA-St Johns SS PACW 115kV	PF
449	P1-2: St Louis-Waconda 57kV	PF
450	P1-2: St Marys-Bethany 115kV	PF
451	P1-2: St Marys-Cedar Hills 115kV	PF
452	P1-2: St Marys-Tektronix 115kV	PF
453	P1-2: St Marys-West Union 115kV	PF
454	P1-2: Sullivan-Twilight 57kV	PF

No	Contingency	Power Flow (PF) or Post-Transient Power Flow (PT)
455	P1-2: Sullivan-Willamette Falls Paper 57kV	PF
456	P1-2: Summit-Welches 24kV	PF
457	P1-2: Swift 1 PACW-Swift 2 CPUD	PF
458	P1-2: Tabor-Arleta 57kV	PF
459	P1-2: Tabor-Kelly Butte 115kV	PF
460	P1-2: Tabor-Russelville PACW 115kV	PF
461	P1-2: Tonquin-Tualatin 115kV	PF
462	P1-2: Troutdale BPA-Troutdale PACW #1 230kV	PF
463	P1-2: Troutdale BPA-Troutdale PACW #2 230kV	PF
464	P1-2: Troutdale PACW-Alderwood PACW 69kV	PF
465	P1-2: West Portland-Boones Ferry 115kV	PF
466	P1-2: West Portland-Garden Home 115kV	PF
467	P1-2: West Portland-Glencullen 115kV	PF
468	P1-2: Yamhill-Scoggins 57kV	PF
469	P1-3: Albany BPA Transformer 230/115kV	PF
470	P1-3: Allston BPA Transformer #1 500/230kV	PF
471	P1-3: Allston BPA Transformer #2 500/230kV	PF
472	P1-3: Allston BPA Transformer #3 230/115kV	PF
473	P1-3: Alvey BPA Transformer #5 500/230kV	PF
474	P1-3: Beaver VRR1 GSU	PF
475	P1-3: Beaver VRR2 GSU	PF
476	P1-3: Beaver VRR3 GSU	PF
477	P1-3: Bethel VWR2 230/115kV	PF
478	P1-3: Bethel VWR4 230/115kV	PF
479	P1-3: Bethel WBR3 115/57kV	PF
480	P1-3: Big Eddy BPA Transformer #2 500/230kV	PF
481	P1-3: Big Eddy BPA Transformer #5 500/230kV	PF
482	P1-3: Blue Lake VWR2 230/115kV	PF
483	P1-3: Blue Lake VWR3 230/115kV	PF
484	P1-3: Canemah WBR1-2-3 115/57kV	PF
485	P1-3: Canemah WBR4-5-6 115/57kV	PF
486	P1-3: Carty GSU	PF
487	P1-3: Carver VWR1 230/115kV	PF
488	P1-3: Carver VWR4 230/115kV	PF
489	P1-3: Century WBR5 115/57kV	PF
490	P1-3: Chemawa BPA Transformer #1 115/57kV	PF
491	P1-3: Chemawa BPA Transformer #2 230/115kV	PF
492	P1-3: Clatsop BPA-Lewis & Clark PACW Transformer 230/115kV	PF
493	P1-3: Cornelius WBR2 115/57kV	PF
494	P1-3: Corral PACW-Ponderosa BPA Transformer 230/115kV	PF
495	P1-3: Coyote GSU	PF
496	P1-3: Dayton WBR2 115/57kV	PF

No	Contingency	Power Flow (PF) or Post-Transient Power Flow (PT)
497	P1-3: Dixonville PACW Transformer 500/230kV	PF
498	P1-3: Evergreen VWR2 230/115kV	PF
499	P1-3: Evergreen VWR3 230/115kV	PF
500	P1-3: Faraday BK13 GSU	PF
501	P1-3: Faraday BK14 GSU	PF
502	P1-3: Faraday WBR12 115/57kV	PF
503	P1-3: Fry PACW Transformer #1 230/115kV	PF
504	P1-3: Fry PACW Transformer #2 230/115kV	PF
505	P1-3: Grand Ronde WBR1 115/57kV	PF
506	P1-3: Gresham VWR1 230/115kV	PF
507	P1-3: Gresham VWR2 230/115kV	PF
508	P1-3: Harborton VWR2 230/115kV	PF
509	P1-3: Hogan WBR1-2-3 115/57kV	PF
510	P1-3: Horizon VWR1 230/115kV	PF
511	P1-3: Horizon VWR2 230/115kV	PF
512	P1-3: Horizon VWR3 230/115kV	PF
513	P1-3: Keeler BPA Transformer #1 230/115kV	PF
514	P1-3: Keeler BPA Transformer #2 500/230kV	PF
515	P1-3: Keeler BPA Transformer #3 230/115kV	PF
516	P1-3: Knott PACW Transformer 115/57kV	PF
517	P1-3: Lane BPA Transformer 500/230kV	PF
518	P1-3: Lexington BPA Transformer 230/115kV	PF
519	P1-3: Longview BPA Transformer #3 230/115kV	PF
520	P1-3: Longview BPA Transformer #4 230/115kV	PF
521	P1-3: McLoughlin VWR4 230/115kV	PF
522	P1-3: McLoughlin VWR5 230/115kV	PF
523	P1-3: Monitor VBR1 230/57kV	PF
524	P1-3: Murrayhill VWR3 230/115kV	PF
525	P1-3: North Fork WR1-2-3 GSU	PF
526	P1-3: Oregon City BPA Transformer 115/57kV	PF
527	P1-3: Orenco WBR1 115/57kV	PF
528	P1-3: Orenco WBR2 115/57kV	PF
529	P1-3: Ostrander BPA Transformer 500/230kV	PF
530	P1-3: Pearl BPA Transformer #1 500/230kV	PF
531	P1-3: Pearl BPA Transformer #2 500/230kV	PF
532	P1-3: Ponderosa AIS BPA Transformer #2 500/230kV	PF
533	P1-3: Ponderosa GIS BPA Transformer #1 500/230kV	PF
534	P1-3: Ponderosa GIS PACW Transformer 230/115kV	PF
535	P1-3: Port Westward 2 GSU #1	PF
536	P1-3: Port Westward 2 GSU #2	PF
537	P1-3: Port Westward VFF1-2-3 GSU	PF
538	P1-3: Redmond BPA Transformer #3 230/115kV	PF

No	Contingency	Power Flow (PF) or Post-Transient Power Flow (PT)
539	P1-3: Redmond BPA Transformer #5 230/115kV	PF
540	P1-3: River Mill BK10 GSU	PF
541	P1-3: River Mill BK9 GSU	PF
542	P1-3: Rivergate VWR1 230/115kV	PF
543	P1-3: Rivergate VWR2-3-4 230/115kV	PF
544	P1-3: Ross BPA Transformer #1 230/115kV	PF
545	P1-3: Ross BPA Transformer #2 230/115kV	PF
546	P1-3: Round Butte ZVR9-10-11 500/230kV	PF
547	P1-3: Salem BPA Transformer 230/115kV	PF
548	P1-3: Santiam BPA Transformer 500/230kV	PF
549	P1-3: Sellwood WBR1 115/57kV	PF
550	P1-3: Sherwood VWR1 230/115kV	PF
551	P1-3: Sherwood VWR2 230/115kV	PF
552	P1-3: St Johns BPA Transformer 230/115kV	PF
553	P1-3: St Marys VWR7 230/115kV	PF
554	P1-3: St Marys VWR8 230/115kV	PF
555	P1-3: St Marys VWR9 230/115kV	PF
556	P1-3: Summit BR1 57/13kV	PF
557	P1-3: Summit FR2 24/13kV	PF
558	P1-3: Tillamook BPA Transformer 230/115kV	PF
559	P1-3: Troutdale BPA Transformer 500/230kV	PF
560	P1-3: Troutdale PACW Transformer #1 230/69kV	PF
561	P1-3: Troutdale PACW Transformer #2 230/69kV	PF
562	P1-3: Troutdale PACW Transformer 230/115kV	PF
563	P1-3: Welches BF2 57/24kV	PF
564	P1-3: Yale PACW GSU	PF
565	P1-4: Alcoa BPA Cap Bank 115kV	PF
566	P1-4: Alvey BPA Cap Bank 230kV	PF
567	P1-4: Alvey BPA Reactor 500kV	PF
568	P1-4: Astoria PACW Cap Bank 115kV	PF
569	P1-4: Big Eddy 2 BPA Cap Bank 230kV	PF
570	P1-4: Big Eddy 3 BPA Cap Bank 230kV	PF
571	P1-4: Boring Cap Bank 57kV	PF
572	P1-4: Butler Cap Bank #1 115kV	PF
573	P1-4: Butler Cap Bank #2 115kV	PF
574	P1-4: Butler Cap Group 115kV (#1 and #2)	PF
575	P1-4: Central Ferry BPA Cap Bank 500kV	PF
576	P1-4: Central Ferry BPA Reactor 500kV	PF
577	P1-4: Chemawa BPA Cap Bank #2 230kV	PF
578	P1-4: Chemawa BPA Cap Bank 115kV	PF
579	P1-4: Chemawa BPA Cap Bank 230kV	PF
580	P1-4: Dilley Cap Bank 57kV	PF

No	Contingency	Power Flow (PF) or Post-Transient Power Flow (PT)
581	P1-4: Dixonville PACW Cap Bank 500kV	PF
582	P1-4: E Cap Bank 115kV	PF
583	P1-4: Evergreen Cap Bank #1 115kV	PF
584	P1-4: Evergreen Cap Bank #2 115kV	PF
585	P1-4: Evergreen Cap Group 115kV (#1 & #2)	PF
586	P1-4: Fry PACW Cap Bank 115kV	PF
587	P1-4: Grizzly BPA Reactor #1 500kV	PF
588	P1-4: Grizzly BPA Reactor #2 500kV	PF
589	P1-4: Grizzly BPA Reactor #3 500kV	PF
590	P1-4: Harborton Cap Bank 115kV	PF
591	P1-4: Hebo BPA Cap Bank 115kV	PF
592	P1-4: John Day BPA Cap Bank 500kV	PF
593	P1-4: Kaster Cap Bank 115kV	PF
594	P1-4: Keeler BPA Cap Bank 500kV	PF
595	P1-4: Keeler East BPA SVC 230kV	PF
596	P1-4: Keeler West BPA Cap Bank #2 230kV	PF
597	P1-4: Keeler West BPA Cap Bank #3 230kV	PF
598	P1-4: Keeler West BPA Reactor #1 230kV	PF
599	P1-4: Lane BPA Cap Bank 230kV	PF
600	P1-4: Liberal Cap Bank 57kV	PF
601	P1-4: Longview BPA Cap Bank #1 230kV	PF
602	P1-4: Longview BPA Cap Bank #2 230kV	PF
603	P1-4: Marion BPA Cap Bank 500kV	PF
604	P1-4: Marion BPA Reactor #1 500 kV	PF
605	P1-4: Marion BPA Reactor #2 500kV	PF
606	P1-4: McMinnville BPA Cap Bank 115kV	PF
607	P1-4: Mt Angel Cap Bank 57kV	PF
608	P1-4: North Marion Cap Bank 57kV	PF
609	P1-4: North Plains Cap Bank 57kV	PF
610	P1-4: Oregon City BPA Cap Bank 115kV	PF
611	P1-4: Ostrander BPA Cap Bank #1 500kV	PF
612	P1-4: Ostrander BPA Cap Bank #2 500kV	PF
613	P1-4: Ostrander BPA Cap Bank #3 500kV	PF
614	P1-4: Ostrander BPA Reactor #1 500 kV	PF
615	P1-4: Ostrander BPA Reactor #2 500kV	PF
616	P1-4: Pearl BPA Cap Bank 230kV	PF
617	P1-4: Pearl BPA Cap Bank 500kV	PF
618	P1-4: Redmond BPA Cap Bank 230kV	PF
619	P1-4: Rivergate Cap Bank 115kV	PF
620	P1-4: Ross BPA Cap Bank #1 230kV	PF
621	P1-4: Ross BPA Cap Bank #2 230kV	PF
622	P1-4: Ross BPA Cap Bank #3 230kV	PF

No	Contingency	Power Flow (PF) or Post-Transient Power Flow (PT)
623	P1-4: Santiam BPA Cap Bank 230kV	PF
624	P1-4: Santiam BPA Reactor 230kV	PF
625	P1-4: Scoggins Cap Bank 57kV	PF
626	P1-4: Sellwood Cap Bank 115kV	PF
627	P1-4: Sheridan Cap Bank 57kV	PF
628	P1-4: Slatt BPA Cap Bank 230kV	PF
629	P1-4: Slatt BPA Cap Bank 500kV	PF
630	P1-4: Springbrook Cap Bank 115kV	PF
631	P1-4: St Helens Cap Bank 115kV	PF
632	P1-4: St Marys Cap Bank #1 115kV	PF
633	P1-4: St Marys Cap Bank #2 115kV	PF
634	P1-4: St Marys Cap Bank #3 115kV	PF
635	P1-4: Sunset Cap Bank #1 115kV	PF
636	P1-4: Tillamook BPA Cap Bank #1 115kV	PF
637	P1-4: Tillamook BPA Cap Bank #2 115kV	PF
638	P1-4: Troutdale BPA Cap Bank #1 230kV	PF
639	P1-4: Troutdale BPA Cap Bank #2 230kV	PF
640	P1-4: Troutdale BPA Cap Bank #3 230kV	PF
641	P1-4: Twilight Cap Bank 57kV	PF
642	P1-4: Urban Cap Bank 115kV	PF
643	P1-4: Welches Cap Bank 57kV	PF
644	P1-4: West Portland Cap Bank 115kV	PF
645	P2-1: Abernethy Tap 1-Jennings Lodge Tap 2 115kV	PF
646	P2-1: Abernethy-Abernethy Tap 1 115kV	PF
647	P2-1: Adair BPA-South COM 115kV	PF
648	P2-1: Albany BPA-Adair BPA 115kV	PF
649	P2-1: Albany BPA-Conser Tap PACW 115kV	PF
650	P2-1: Albina PACW-Albina Tap PACW 115kV	PF
651	P2-1: Albina PACW-Basin Tap 115kV	PF
652	P2-1: Alder-Glencoe Tap 115kV	PF
653	P2-1: Alderwood PACW-Killingsworth PACW 69kV	PF
654	P2-1: Allston BPA-Delena CLPUD 115kV	PF
655	P2-1: Allston BPA-Driscoll BPA Tap 230kV	PF
656	P2-1: Allston BPA-Nys Tap CRPUD 115kV	PF
657	P2-1: Allston BPA-Rainier Tap 115kV	PF
658	P2-1: Amity Tap 57kV	PF
659	P2-1: Armstrong CRPUD Tap-Betsy Johnson CRPUD Tap 115kV	PF
660	P2-1: Arrowhead-Coffee Creek Tap 1 115kV	PF
661	P2-1: Astoria PACW-Astoria Tap PACW 115kV	PF
662	P2-1: Astoria PACW-Fern Hill PACW 115kV	PF
663	P2-1: Astoria Tap PACW-Seaside PACW 115kV	PF
664	P2-1: Baker Creek MW&L-Walnut City MW&L 115kV	PF

No	Contingency	Power Flow (PF) or Post-Transient Power Flow (PT)
665	P2-1: Baker Creek MW&L-Walnut City Tap BPA 115kV	PF
666	P2-1: Bakers Corner CCPD-Pacific Way CCPD 115kV	PF
667	P2-1: Banks-Gales Creek Tap 57kV	PF
668	P2-1: Barnes-Barnes Tap 1 115kV	PF
669	P2-1: Basin Tap-Swan Island Tap 2 115kV	PF
670	P2-1: Beaver BPA-Hebo BPA 115kV	PF
671	P2-1: Bell-Lents 115kV	PF
672	P2-1: Bethany-Cornell Tap 1 115kV	PF
673	P2-1: Bethany-Willbridge Tap 115kV	PF
674	P2-1: Bethel-Bethel South 115kV	PF
675	P2-1: Bethel-Middle Grove Tap 1 115kV	PF
676	P2-1: Bethel-Monitor Tap 230kV	PF
677	P2-1: Big Eddy BPA-Maupin BPA 230kV	PF
678	P2-1: Big Eddy BPA-Parkdale BPA 230kV	PF
679	P2-1: Bloss PACW-Columbia PACW 115kV	PF
680	P2-1: Blue Lake-Rockwood Tap 1 115kV	PF
681	P2-1: Blue Lake-Rockwood Tap 2 115kV	PF
682	P2-1: Booth Bend MW&L-Gormley MW&L 115kV	PF
683	P2-1: Boring-Eagle Creek Tap 1 57kV	PF
684	P2-1: Boring-Eagle Creek Tap 2 57kV	PF
685	P2-1: Boring-Hogan Tap 57kV	PF
686	P2-1: Boring-Sandy Tap 1 57kV	PF
687	P2-1: Boyer PACW-Devils Lake PACW 115kV	PF
688	P2-1: Boyer PACW-Nestucca TPUD 115kV	PF
689	P2-1: Brightwood Tap 2-Sandy Tap 2 57kV	PF
690	P2-1: Butler-Oak Hills Tap 2 115kV	PF
691	P2-1: Canemah-Mt Pleasant Tap 1 115kV	PF
692	P2-1: Cannon Beach PACW-Seaside PACW 115kV	PF
693	P2-1: Cannon Beach TPUD-Nehalem Tap TPUD 115kV	PF
694	P2-1: Canyon-Sulzer Tap 115kV	PF
695	P2-1: Canyon-Sylvan Tap 115kV	PF
696	P2-1: Captain Jack BPA-Ponderosa BPA 500kV	PF
697	P2-1: Carlton BPA-Carlton Tap BPA 115kV	PF
698	P2-1: Carlton BPA-Cascade Tap BPA 230kV	PF
699	P2-1: Carlton BPA-Windishar MW&L 115kV	PF
700	P2-1: Carlton Tap BPA-Filbert Tap BPA 115kV	PF
701	P2-1: Carlton Tap BPA-Walnut City Tap BPA 115kV	PF
702	P2-1: Carver Load-Carver Tap 2 115kV	PF
703	P2-1: Carver Tap 2-Pleasant Valley 115kV	PF
704	P2-1: Carver-Carver Tap 2 115kV	PF
705	P2-1: Carver-Hogan North Tap 1 115kV	PF
706	P2-1: Cascade Tap BPA-Cascade Steel BPA 230kV	PF

No	Contingency	Power Flow (PF) or Post-Transient Power Flow (PT)
707	P2-1: Cathlamet WKPD-Wahkiakum WKPD 115kV	PF
708	P2-1: Chemawa BPA-Fargo 115kV	PF
709	P2-1: Chemawa BPA-Hughes SEC 115kV	PF
710	P2-1: Chemawa BPA-Read Tap SEC 115kV	PF
711	P2-1: Clatskanie BPA-Delena CLPUD 115kV	PF
712	P2-1: Clatskanie BPA-Mist BPA 115kV	PF
713	P2-1: Clatsop BPA-Driscoll Tap BPA 230kV	PF
714	P2-1: Coffee Creek-Coffee Creek Tap 1 115kV	PF
715	P2-1: Columbia PACW-Mallory PACW 115kV	PF
716	P2-1: Cornelius-Dilley 57kV	PF
717	P2-1: Cornelius-Gales Creek Tap 57kV	PF
718	P2-1: Cornelius-Hillsboro Tap 1 57kV	PF
719	P2-1: Cornelius-Hillsboro Tap 2 57kV	PF
720	P2-1: Cornell Tap 1-St Marys East Tap 1 115kV	PF
721	P2-1: Cornell-Cornell Tap 1 115kV	PF
722	P2-1: Cully PACW-Gateway Tap East PACW 115kV	PF
723	P2-1: Cully PACW-Gateway Tap West PACW 115kV	PF
724	P2-1: Culver-Bethel South 115kV	PF
725	P2-1: Culver-Turner Tap 115kV	PF
726	P2-1: Curtis-Pen Park Tap 1 115kV	PF
727	P2-1: Dayton-Amity 57kV	PF
728	P2-1: Dayton-Dayton Tap 115kV	PF
729	P2-1: Dayton-Unionvale 57kV	PF
730	P2-1: Delaware-Pen Park Tap 2 115kV	PF
731	P2-1: Dilley Tap 57kV	PF
732	P2-1: Driscoll BPA-Cathlamet WKPD 115kV	PF
733	P2-1: Driscoll BPA-Driscoll Tap BPA 230kV	PF
734	P2-1: Driscoll BPA-Knappa PACW 115kV	PF
735	P2-1: Driscoll BPA-Mist WEC 115kV	PF
736	P2-1: Driscoll BPA-Wauna CLPUD 230kV	PF
737	P2-1: Dunns Corner-Sandy Tap 1 57kV	PF
738	P2-1: Dunns Corner-Sandy Tap 2 57kV	PF
739	P2-1: Durham Tap 2-Tigard Tap 1 115kV	PF
740	P2-1: Durham-Durham Tap 2 115kV	PF
741	P2-1: Dutch Canyon CRPUD-Warren BPA 115kV	PF
742	P2-1: Eagle Creek Tap 1-Estacada Tap 2 57kV	PF
743	P2-1: Eagle Creek-Eagle Creek Tap 1 57kV	PF
744	P2-1: Eastport-Ramapo Tap 1 115kV	PF
745	P2-1: Estacada-Estacada Tap 1 57kV	PF
746	P2-1: E-Sulzer Tap 115kV	PF
747	P2-1: E-Willbridge Tap 115kV	PF
748	P2-1: Fairgrounds BPA-Warren BPA 115kV	PF

No	Contingency	Power Flow (PF) or Post-Transient Power Flow (PT)
749	P2-1: Faraday-Estacada Tap 1 57kV	PF
750	P2-1: Faraday-Estacada Tap 2 57kV	PF
751	P2-1: Faraday-Redland Tap 1 115kV	PF
752	P2-1: Fern Hill PACW-Knappa PACW 115kV	PF
753	P2-1: Forest Grove BPA-Filbert Tap BPA 115kV	PF
754	P2-1: Forest Grove BPA-Thatch COF 115kV	PF
755	P2-1: Fruit Valley Tap PACW-Hayden Tap PACW 115kV	PF
756	P2-1: Gales Creek-Gales Creek Tap 57kV	PF
757	P2-1: Garden Home-West Portland Tap 115kV	PF
758	P2-1: Garibaldi TPUD-Mohler TPUD 115kV	PF
759	P2-1: Gateway Tap East PACW-Parkrose Tap PACW 115kV	PF
760	P2-1: Gateway Tap West PACW-Hollywood Tap PACW 115kV	PF
761	P2-1: Glencoe Tap 115kV	PF
762	P2-1: Glencullen-Sylvan Tap 115kV	PF
763	P2-1: Glendoveer-Centennial Tap 2 115kV	PF
764	P2-1: Glendoveer-Hemlock Tap 115kV	PF
765	P2-1: Goble CRPUD-Rainier Tap 115kV	PF
766	P2-1: Gormley MW&L-Walnut City MW&L 115kV	PF
767	P2-1: Grand Ronde-Willamina Tap 2 57kV	PF
768	P2-1: Grays River WKPD-Wahkiakum WKPD 115kV	PF
769	P2-1: Gresham-Centennial Tap 2 115kV	PF
770	P2-1: Gresham-Midway Tap 1 115kV	PF
771	P2-1: Gresham-Ramapo Tap 115kV	PF
772	P2-1: Harborton-Rivergate South Tap 115kV	PF
773	P2-1: Harmony-Harmony Tap 1 115kV	PF
774	P2-1: Hazel Dell PACW-Fruit Valley Tap PACW 115kV	PF
775	P2-1: Hazelwood PACW-Oremet PACW 115kV	PF
776	P2-1: Hebo BPA-Nestucca TPUD 115kV	PF
777	P2-1: Hemlock Tap PACW-Parkrose Tap PACW 115kV	PF
778	P2-1: Hemlock Tap-Rockwood Tap 2 115kV	PF
779	P2-1: Hemlock-Hemlock Tap 1 115kV	PF
780	P2-1: Hemlock-Hemlock Tap PACW 115kV	PF
781	P2-1: Hillcrest-Barnes Tap 1 115kV	PF
782	P2-1: Hillsboro Tap 1-Main Tap 1 57kV	PF
783	P2-1: Hillsboro Tap 2-Main Tap 2 57kV	PF
784	P2-1: Hillsboro-Hillsboro Tap 2 57kV	PF
785	P2-1: Hogan North-Hogan North Tap 1 115kV	PF
786	P2-1: Hogan South-Hogan Tap 57kV	PF
787	P2-1: Hogan-Hogan North Tap 1 115kV	PF
788	P2-1: Holladay PACW-Harrison Reactor PACW 115kV	PF
789	P2-1: Hollywood PACW-Hollywood Tap PACW 115kV	PF
790	P2-1: Huber Tap 1-Murrayhill Tap 1 115kV	PF

No	Contingency	Power Flow (PF) or Post-Transient Power Flow (PT)
791	P2-1: Huber-Huber Tap 1 115kV	PF
792	P2-1: Island-Jennings Lodge Tap 2 115kV	PF
793	P2-1: Jennings Lodge-Jennings Lodge Tap 2 115kV	PF
794	P2-1: Kaster-Armstrong CRPUD Tap 115kV	PF
795	P2-1: Kelley Point-Hayden Island Tap 115kV	PF
796	P2-1: Kelley Point-Pot Ash Tap 115kV	PF
797	P2-1: King City-Tigard Tap 1 115kV	PF
798	P2-1: Knott PACW-Albina Tap PACW 115kV	PF
799	P2-1: Knott PACW-Hollywood PACW 115kV	PF
800	P2-1: Knott PACW-Vernon Tap PACW 115kV	PF
801	P2-1: Leland-Mulino 57kV	PF
802	P2-1: Lents Tap 115kV	PF
803	P2-1: Lents-Hogan Tap 57kV	PF
804	P2-1: Lents-Ramapo Tap 115kV	PF
805	P2-1: Lewis & Clark PACW-Astoria Tap PACW 115kV	PF
806	P2-1: Lewis & Clark PACW-Warrenton PACW 115kV	PF
807	P2-1: Lexington BPA-Pacific Way CCPD 115kV	PF
808	P2-1: Lexington BPA-Woodland BPA 230kV	PF
809	P2-1: Liberal-Mulino 57kV	PF
810	P2-1: Longview BPA-Bakers Corner CCPD 115kV	PF
811	P2-1: Longview BPA-Nys Tap CRPUD 115kV	PF
812	P2-1: Main-Main Tap 1 57kV	PF
813	P2-1: Mallory PACW-Vernon Tap PACW 115kV	PF
814	P2-1: Market-Middle Grove Tap 1 115kV	PF
815	P2-1: Maxim Tap 1-Maxim Tap 2 115kV	PF
816	P2-1: Maxim Tap 1-St Marys East Tap 2 115kV	PF
817	P2-1: McLoughlin-Abernethy Tap 1 115kV	PF
818	P2-1: McLoughlin-Monitor Tap 230kV	PF
819	P2-1: McLoughlin-Mt Pleasant Tap 1 115kV	PF
820	P2-1: McLoughlin-Pearl Tap BPA 230kV	PF
821	P2-1: McLoughlin-Redland Tap 1 115kV	PF
822	P2-1: McMinnville BPA-Booth Bend MW&L 115kV	PF
823	P2-1: McMinnville BPA-Dayton Tap 115kV	PF
824	P2-1: McMinnville BPA-Walnut City Tap BPA 115kV	PF
825	P2-1: McMinnville BPA-Windishar MW&L 115kV	PF
826	P2-1: Merwin PACW-Ariel CCPD 115kV	PF
827	P2-1: Merwin PACW-Chelatchie CPU 115kV	PF
828	P2-1: Middle Grove-Middle Grove Tap 1 115kV	PF
829	P2-1: Midway Tap 1 115kV-Ramapo Tap 1 115kV	PF
830	P2-1: Midway-Midway Tap 1 115kV	PF
831	P2-1: Mill Creek-Barnes Tap 115kV	PF
832	P2-1: Mill Creek-Turner Tap 115kV	PF

No	Contingency	Power Flow (PF) or Post-Transient Power Flow (PT)
833	P2-1: Mohler TPUD-Nehalem Tap TPUD 115kV	PF
834	P2-1: Molalla-Scotts Mills Tap 57kV	PF
835	P2-1: Monitor-Monitor Tap 230kV	PF
836	P2-1: Monmouth BPA-South COM 115kV	PF
837	P2-1: Mt Angel-Scotts Mills Tap 57kV	PF
838	P2-1: Mt Pleasant-Mt Pleasant Tap 1 115kV	PF
839	P2-1: Mulino Tap 57kV	PF
840	P2-1: Multnomah Tap 1-Urban Tap 115kV	PF
841	P2-1: Multnomah-Multnomah Tap 2 115kV	PF
842	P2-1: Murrayhill Tap 1-Murrayhill Load 115kV	PF
843	P2-1: Murrayhill-Murrayhill Tap 1 115kV	PF
844	P2-1: Naselle BPA-Grays River WKPD 115kV	PF
845	P2-1: Nehalem TPUD-Nehalem Tap TPUD 115kV	PF
846	P2-1: Newberg-Dayton Tap 115kV	PF
847	P2-1: North Bonneville BPA-Sifton Tap 1 BPA 230kV	PF
848	P2-1: North Bonneville BPA-Sifton Tap 2 BPA 230kV	PF
849	P2-1: North Marion-Canby Tap 57kV	PF
850	P2-1: Northern-Swan Tap 115kV	PF
851	P2-1: Oak Hills-Oak Hills Tap 2 115kV	PF
852	P2-1: Oregon City BPA-Fargo 115kV	PF
853	P2-1: Orenco-Main Tap 1 57kV	PF
854	P2-1: Orenco-Main Tap 2 57kV	PF
855	P2-1: Parkrose PACW-Parkrose Tap PACW 115kV	PF
856	P2-1: Pearl BPA-Pearl Tap BPA 230kV	PF
857	P2-1: Pen Park Tap 1-Swan Tap 115kV	PF
858	P2-1: Pen Park Tap 2-Swan Island Tap 2 115kV	PF
859	P2-1: Pen Park-Pen Park Tap 1 115kV	PF
860	P2-1: Ponderosa BPA-Summer Lake BPA 500kV	PF
861	P2-1: Pot Ash Tap 1-Rivergate South Tap 115kV	PF
862	P2-1: Rainier CLPUD-Rainier Tap 115kV	PF
863	P2-1: Raleigh Hills-Multnomah Tap 2 115kV	PF
864	P2-1: Ramapo-Ramapo Tap 1 115kV	PF
865	P2-1: Redmond BPA-Maupin BPA 230kV	PF
866	P2-1: Reedville-Huber Tap 1 115kV	PF
867	P2-1: Reedville-Huber Tap 2 115kV	PF
868	P2-1: River Mill-Eagle Creek Tap 2 57kV	PF
869	P2-1: River Mill-Estacada Tap 1 57kV	PF
870	P2-1: River Road CPU-Fruit Valley Tap PACW 115kV	PF
871	P2-1: Riverview-Riverview Tap 1 115kV	PF
872	P2-1: Rockwood-Rockwood Tap 1 115kV	PF
873	P2-1: Ross BPA-Sifton Tap 1 BPA 230kV	PF
874	P2-1: Ross BPA-Sifton Tap 2 BPA 230kV	PF

No	Contingency	Power Flow (PF) or Post-Transient Power Flow (PT)
875	P2-1: Ross BPA-Woodland BPA 500kV	PF
876	P2-1: Salem Alumina SEC-Read Tap SEC 115kV	PF
877	P2-1: Salem BPA-Conser Tap PACW 115kV	PF
878	P2-1: Salem BPA-Hughes SEC 115kV	PF
879	P2-1: Salem BPA-Monmouth BPA 115kV	PF
880	P2-1: Sandy-Sandy Tap 1 57kV	PF
881	P2-1: Santiam BPA-Wren BPA 230kV	PF
882	P2-1: Scappoose CRPUD-Betsy Johnson CRPUD Tap 115kV	PF
883	P2-1: Schnitzer-Schnitzer Tap 115kV	PF
884	P2-1: Scotts Mills-Scotts Mills Tap 57kV	PF
885	P2-1: Sellwood-Harmony Tap 1 115kV	PF
886	P2-1: Sellwood-Urban Tap 115kV	PF
887	P2-1: Sheridan-Amity 57kV	PF
888	P2-1: Sheridan-Willamina Tap 1 57kV	PF
889	P2-1: Sherwood-Cascade Tap BPA 230kV	PF
890	P2-1: Sherwood-Coffee Creek Tap 1 115kV	PF
891	P2-1: Sherwood-Pearl Tap BPA 230kV	PF
892	P2-1: Sifton BPA-Sifton Tap 1 BPA 230kV	PF
893	P2-1: Sifton BPA-Sifton Tap 2 BPA 230kV	PF
894	P2-1: South Fork TPUD-Timber BPA 115kV	PF
895	P2-1: St Helens-Fairgrounds CRPUD 115kV	PF
896	P2-1: St Helens-Goble Tap CRPUD 115kV	PF
897	P2-1: St Johns BPA-Albina Tap PACW 115kV	PF
898	P2-1: St Johns BPA-Dutch Canyon CRPUD 115kV	PF
899	P2-1: St Johns SS PACW-Bloss PACW 115kV	PF
900	P2-1: St Johns SS PACW-Hayden Tap PACW 115kV	PF
901	P2-1: St Marys East-St Marys East Tap 2 115kV	PF
902	P2-1: St Marys-Huber Tap 2 115kV	PF
903	P2-1: St Marys-Oak Hills Tap 2 115kV	PF
904	P2-1: St Marys-St Marys East Tap 1 115kV	PF
905	P2-1: St Marys-St Marys East Tap 2 115kV	PF
906	P2-1: Sulzer-Sulzer Tap 115kV	PF
907	P2-1: Swan Island-Swan Island Tap 1 115kV	PF
908	P2-1: Swift 2 PACW-Woodland BPA 230kV	PF
909	P2-1: Sylvan-Sylvan Tap 1 115kV	PF
910	P2-1: Tabor-Glencoe Tap 115kV	PF
911	P2-1: Tektronix-Maxim Tap 2 115kV	PF
912	P2-1: Thatch COF-Timber BPA 115kV	PF
913	P2-1: Tigard-Tigard Tap 1 115kV	PF
914	P2-1: Tillamook BPA-Beaver BPA 115kV	PF
915	P2-1: Tillamook BPA-Garibaldi TPUD 115kV	PF
916	P2-1: Tillamook BPA-South Fork TPUD 115kV	PF

No	Contingency	Power Flow (PF) or Post-Transient Power Flow (PT)
917	P2-1: Tillamook BPA-Trask RV TPUD 115kV	PF
918	P2-1: Toledo BPA-Wren BPA 230kV	PF
919	P2-1: Town Center-Harmony Tap 1 115kV	PF
920	P2-1: Troutdale BPA-Parkdale BPA 230kV	PF
921	P2-1: Troutdale PACW-Hemlock Tap PACW 115kV	PF
922	P2-1: Turner-Turner Tap 115kV	PF
923	P2-1: Twilight-Canby Tap 57kV	PF
924	P2-1: Unionvale Tap 57kV	PF
925	P2-1: Urban-Urban Tap 115kV	PF
926	P2-1: Vernon-Vernon Tap PACW 115kV	PF
927	P2-1: Wallace-Unionvale 57kV	PF
928	P2-1: Welches-Brightwood Tap 2 57kV	PF
929	P2-1: West Portland Load-West Portland Tap 1 115kV	PF
930	P2-1: West Portland-Durham Tap 2 115kV	PF
931	P2-1: West Portland-Multnomah Tap 1 115kV	PF
932	P2-1: Willamina Tap 1-Willamina Tap 2 57kV	PF
933	P2-1: Yale PACW-Chelatchie CPU 115kV	PF
934	P2-2: Albina PACW 115kV	PF
935	P2-2: Allston BPA 115kV	PF
936	P2-2: Alvey North BPA 230kV	PF
937	P2-2: Alvey South BPA 230kV	PF
938	P2-2: Astoria PACW 115kV	PF
939	P2-2: Banks 57kV	PF
940	P2-2: Beaver 230kV	PF
941	P2-2: Beaverton 115kV	PF
942	P2-2: Bethel 230kV	PF
943	P2-2: Bethel 57kV	PF
944	P2-2: Boring 57kV	PF
945	P2-2: Boyer PACW 115kV	PF
946	P2-2: Canemah 115kV	PF
947	P2-2: Canemah B51 57kV	PF
948	P2-2: Canemah B52 57kV	PF
949	P2-2: Cardwell BPA 115kV	PF
950	P2-2: Carver W51 115kV	PF
951	P2-2: Carver W52 115kV	PF
952	P2-2: Chemawa BPA 115kV	PF
953	P2-2: Chemawa BPA 230kV	PF
954	P2-2: Chemawa BPA 57kV	PF
955	P2-2: Cornelius 57kV	PF
956	P2-2: Culver 115kV	PF
957	P2-2: Dayton 57kV	PF
958	P2-2: Dunns Corner South 57kV	PF

No	Contingency	Power Flow (PF) or Post-Transient Power Flow (PT)
959	P2-2: Fairview 115kV	PF
960	P2-2: Faraday 57kV	PF
961	P2-2: Glendoveer 115kV	PF
962	P2-2: Grand Ronde 115kV	PF
963	P2-2: Gresham 230kV	PF
964	P2-2: Gresham W53 115kV	PF
965	P2-2: Gresham W54 115kV	PF
966	P2-2: Harrison East PACW 115kV	PF
967	P2-2: Harrison West PACW 115kV	PF
968	P2-2: Hogan South 115kV	PF
969	P2-2: Hogan South 57kV	PF
970	P2-2: Holgate 115kV	PF
971	P2-2: Holladay PACW 115kV	PF
972	P2-2: Knott East PACW 57kV	PF
973	P2-2: La Pine BPA 115kV	PF
974	P2-2: La Pine BPA 230kV	PF
975	P2-2: Lane 1 BPA 230kV	PF
976	P2-2: Lane 2 BPA 230kV	PF
977	P2-2: Lane BPA 115kV	PF
978	P2-2: Leland 57kV	PF
979	P2-2: Lents 57kV	PF
980	P2-2: Lexington BPA 230kV	PF
981	P2-2: Liberty 115kV	PF
982	P2-2: Longview North BPA 115kV	PF
983	P2-2: Longview South BPA 115kV	PF
984	P2-2: Market 115kV	PF
985	P2-2: McLoughlin East 230kV	PF
986	P2-2: McLoughlin W51 115kV	PF
987	P2-2: McLoughlin W52 115kV	PF
988	P2-2: McLoughlin West 230kV	PF
989	P2-2: Meridian 115kV	PF
990	P2-2: Mill Creek 115kV	PF
991	P2-2: Molalla 57kV	PF
992	P2-2: Monitor 57kV	PF
993	P2-2: Mt Angel 57kV	PF
994	P2-2: Newberg 115kV	PF
995	P2-2: North Marion 57kV	PF
996	P2-2: Northern 115kV	PF
997	P2-2: Oak Grove East 115kV	PF
998	P2-2: Oak Grove West 115kV	PF
999	P2-2: Oremet PACW 115kV	PF
1000	P2-2: Orenco North 57kV	PF

No	Contingency	Power Flow (PF) or Post-Transient Power Flow (PT)
1001	P2-2: Orenco South 57kV	PF
1002	P2-2: Oswego 115kV	PF
1003	P2-2: Pelton 230kV	PF
1004	P2-2: Progress 115kV	PF
1005	P2-2: Redmond BPA 69kV	PF
1006	P2-2: Redmond East BPA 115kV	PF
1007	P2-2: Redmond East BPA 230kV	PF
1008	P2-2: Redmond West BPA 115kV	PF
1009	P2-2: Redmond West BPA 230kV	PF
1010	P2-2: Reedville 115kV	PF
1011	P2-2: River Mill 57kV	PF
1012	P2-2: River Road CPU 115kV	PF
1013	P2-2: Rivergate 230kV	PF
1014	P2-2: Rivergate W53, W54, W55 115kV	PF
1015	P2-2: Rivergate W58 115kV	PF
1016	P2-2: Rock Creek 115kV	PF
1017	P2-2: Ross East BPA 230kV	PF
1018	P2-2: Round Butte North 230kV	PF
1019	P2-2: Round Butte South 230kV	PF
1020	P2-2: Ruby 115kV	PF
1021	P2-2: Salem 57kV	PF
1022	P2-2: Salem BPA 115kV	PF
1023	P2-2: Santiam East BPA 230kV	PF
1024	P2-2: Santiam West BPA 230kV	PF
1025	P2-2: Sellwood 115kV	PF
1026	P2-2: Sellwood 57kV	PF
1027	P2-2: Sheridan 57kV	PF
1028	P2-2: Sherwood W53 115kV	PF
1029	P2-2: Sherwood W54 115kV	PF
1030	P2-2: Springbrook 115kV	PF
1031	P2-2: St Helens North 115kV	PF
1032	P2-2: St Johns SS PACW 115kV	PF
1033	P2-2: St Louis 57kV	PF
1034	P2-2: Sullivan 57kV	PF
1035	P2-2: Tabor 115kV	PF
1036	P2-2: Tabor 57kV	PF
1037	P2-2: Tektronix 115kV	PF
1038	P2-2: Tillamook BPA 115kV	PF
1039	P2-2: Troutdale PACW 69kV	PF
1040	P2-2: Urban W53 115kV	PF
1041	P2-2: Urban W54 115kV	PF
1042	P2-2: Urban W55 115kV	PF

No	Contingency	Power Flow (PF) or Post-Transient Power Flow (PT)
1043	P2-2: Urban W56 115kV	PF
1044	P2-2: Wacker W61 115kV	PF
1045	P2-2: Wacker W62 115kV	PF
1046	P2-2: West Portland 115kV	PF
1047	P2-2: Wilsonville 115kV	PF
1048	P2-2: Yamhill 57kV	PF
1049	P2-3: Alder W122 or W232 115kV	PF
1050	P2-3: Alder W152 or W242 115kV	PF
1051	P2-3: Allston 4502 BPA 500kV	PF
1052	P2-3: Allston 4690 BPA 500kV	PF
1053	P2-3: Allston A1364 BPA 230kV	PF
1054	P2-3: Alvey 5081, 5084, or 5087 BPA 500kV	PF
1055	P2-3: Ashe 4888 BPA 500kV	PF
1056	P2-3: Ashe 4891 BPA 500kV	PF
1057	P2-3: Ashe 4937 BPA 500kV	PF
1058	P2-3: Ashe 4940 BPA 500kV	PF
1059	P2-3: Bell W122 or W262 115kV	PF
1060	P2-3: Bell W252 or W342 115kV	PF
1061	P2-3: Bethel W342 115kV	PF
1062	P2-3: Bethel W346 115kV	PF
1063	P2-3: Bethel W352 115kV	PF
1064	P2-3: Bethel W358 115kV	PF
1065	P2-3: Bethel W368 115kV	PF
1066	P2-3: Big Eddy 4200 BPA 500kV	PF
1067	P2-3: Big Eddy 4202 BPA 500kV	PF
1068	P2-3: Blue Lake V202 230kV	PF
1069	P2-3: Blue Lake V212 230kV	PF
1070	P2-3: Blue Lake V342 230kV	PF
1071	P2-3: Blue Lake V352 230kV	PF
1072	P2-3: Blue Lake W110 115kV	PF
1073	P2-3: Blue Lake W204 115kV	PF
1074	P2-3: Blue Lake W210 115kV	PF
1075	P2-3: Blue Lake W216 115kV	PF
1076	P2-3: Blue Lake W230 115kV	PF
1077	P2-3: Blue Lake W244 115kV	PF
1078	P2-3: Blue Lake W248 115kV	PF
1079	P2-3: Blue Lake W258 115kV	PF
1080	P2-3: Brookwood W172 115kV	PF
1081	P2-3: Brookwood W352 or W362 115kV	PF
1082	P2-3: Buckley 4961, 4964, or 4967 BPA 500kV	PF
1083	P2-3: Butler W120 115kV	PF
1084	P2-3: Butler W232 115kV	PF

No	Contingency	Power Flow (PF) or Post-Transient Power Flow (PT)
1085	P2-3: Butler W344 115kV	PF
1086	P2-3: Butler W456 115kV	PF
1087	P2-3: Canyon W102 115kV	PF
1088	P2-3: Canyon W106 115kV	PF
1089	P2-3: Canyon W114 115kV	PF
1090	P2-3: Canyon W208 115kV	PF
1091	P2-3: Captain Jack 4924 BPA 500kV	PF
1092	P2-3: Captain Jack 4977 BPA 500kV	PF
1093	P2-3: Captain Jack 4980 BPA 500kV	PF
1094	P2-3: Captain Jack 4983 BPA 500kV	PF
1095	P2-3: Captain Jack 4986 BPA 500kV	PF
1096	P2-3: Captain Jack 4990 BPA 500kV	PF
1097	P2-3: Captain Jack 4993 BPA 500kV	PF
1098	P2-3: Captain Jack 4996 BPA 500kV	PF
1099	P2-3: Carver V180 230kV	PF
1100	P2-3: Carver V184 230kV	PF
1101	P2-3: Carver V188 230kV	PF
1102	P2-3: Carver V460 230kV	PF
1103	P2-3: Carver V464 230kV	PF
1104	P2-3: Cherry Grove PCB1 CPU 115kV	PF
1105	P2-3: Coyote 5184 BPA 500kV	PF
1106	P2-3: Coyote 5187 500kV	PF
1107	P2-3: Coyote 5190 BPA 500kV	PF
1108	P2-3: Coyote 5193 500kV	PF
1109	P2-3: Curtis W122 115kV	PF
1110	P2-3: Curtis W132 115kV	PF
1111	P2-3: Curtis W252 115kV	PF
1112	P2-3: Curtis W342 115kV	PF
1113	P2-3: E W250 115kV	PF
1114	P2-3: E W370 or W398 115kV	PF
1115	P2-3: E W374 115kV	PF
1116	P2-3: E W386 115kV	PF
1117	P2-3: E W390 115kV	PF
1118	P2-3: Evergreen V230 230kV	PF
1119	P2-3: Evergreen W110 115kV	PF
1120	P2-3: Evergreen W122 115kV	PF
1121	P2-3: Evergreen W142 115kV	PF
1122	P2-3: Evergreen W146 115kV	PF
1123	P2-3: Faraday W202 115kV	PF
1124	P2-3: Faraday W212 115kV	PF
1125	P2-3: Faraday W222 115kV	PF
1126	P2-3: Faraday W232 115kV	PF

No	Contingency	Power Flow (PF) or Post-Transient Power Flow (PT)
1127	P2-3: Faraday W242 115kV	PF
1128	P2-3: Glisan W114 or W130 115kV	PF
1129	P2-3: Glisan W118 115kV	PF
1130	P2-3: Glisan W122 115kV	PF
1131	P2-3: Glisan W132 115kV	PF
1132	P2-3: Grizzly 4046 BPA 500kV	PF
1133	P2-3: Grizzly 4048 BPA 500kV	PF
1134	P2-3: Grizzly 4052 BPA 500kV	PF
1135	P2-3: Grizzly 5025 BPA 500kV	PF
1136	P2-3: Grizzly 5028 BPA 500kV	PF
1137	P2-3: Grizzly 5034 BPA 500kV	PF
1138	P2-3: Grizzly 5040 BPA 500kV	PF
1139	P2-3: Harborton V242 230kV	PF
1140	P2-3: Harborton W114 115kV	PF
1141	P2-3: Harborton W126 115kV	PF
1142	P2-3: Harborton W162 115kV	PF
1143	P2-3: Harrison W122 or W232 115kV	PF
1144	P2-3: Harrison W172 115kV	PF
1145	P2-3: Harrison W342 115kV	PF
1146	P2-3: Hazel Dell PCB1 CPU 115kV	PF
1147	P2-3: Hazel Dell PCB2 CPU 115kV	PF
1148	P2-3: Hillcrest W144 115kV	PF
1149	P2-3: Hillcrest W168 115kV	PF
1150	P2-3: Hillcrest W206 115kV	PF
1151	P2-3: Horizon V112 230kV	PF
1152	P2-3: Horizon V212 230kV	PF
1153	P2-3: Horizon V312 230kV	PF
1154	P2-3: John Day 4131 BPA 500kV	PF
1155	P2-3: John Day 4134 BPA 500kV	PF
1156	P2-3: John Day 4140 BPA 500kV	PF
1157	P2-3: John Day 4143 BPA 500kV	PF
1158	P2-3: John Day 4158 BPA 500kV	PF
1159	P2-3: John Day 4167 BPA 500kV	PF
1160	P2-3: John Day 4170 BPA 500kV	PF
1161	P2-3: John Day 4176 BPA 500kV	PF
1162	P2-3: John Day 4179 BPA 500kV	PF
1163	P2-3: John Day 4194 BPA 500kV	PF
1164	P2-3: John Day 4197 BPA 500kV	PF
1165	P2-3: John Day 4825 BPA 500kV	PF
1166	P2-3: John Day 5444 BPA 500kV	PF
1167	P2-3: Knott 2P_NEW PACW 115kV	PF
1168	P2-3: Knott 2P103 PACW 115kV	PF

No	Contingency	Power Flow (PF) or Post-Transient Power Flow (PT)
1169	P2-3: Knott 2P91 PACW 115kV	PF
1170	P2-3: Knott 2P92 PACW 115kV	PF
1171	P2-3: Knott 2P93 PACW 115kV	PF
1172	P2-3: Knott 2P94 PACW 115kV	PF
1173	P2-3: Malin 4019 PACW 500kV	PF
1174	P2-3: Malin 4064 BPA 500kV	PF
1175	P2-3: Malin 4066 BPA 500kV	PF
1176	P2-3: Malin 4070 500kV	PF
1177	P2-3: Malin 4072 BPA 500kV	PF
1178	P2-3: Malin 4186 BPA 500kV	PF
1179	P2-3: Malin 4576 PACW 500kV	PF
1180	P2-3: Malin 4582 BPA 500kV	PF
1181	P2-3: Malin 4591 PACW 500kV	PF
1182	P2-3: Marion 4355 BPA 500kV	PF
1183	P2-3: Marion 4368 BPA 500kV	PF
1184	P2-3: Marion 4371 BPA 500kV	PF
1185	P2-3: Marion 4377 BPA 500kV	PF
1186	P2-3: Marion 4380 BPA 500kV	PF
1187	P2-3: Marion 4389 BPA 500kV	PF
1188	P2-3: Marquam W108 115kV	PF
1189	P2-3: Marquam W224 115kV	PF
1190	P2-3: Marquam W340 115kV	PF
1191	P2-3: Marquam W456 115kV	PF
1192	P2-3: McGill W214 115kV	PF
1193	P2-3: McGill W228 115kV	PF
1194	P2-3: McGill W242 115kV	PF
1195	P2-3: McNary 4231 BPA 500kV	PF
1196	P2-3: McNary 5211 BPA 500kV	PF
1197	P2-3: Merwin 2P1 or 2P3 PACW 115kV	PF
1198	P2-3: Merwin 2P2 or 2P4 PACW 115kV	PF
1199	P2-3: Merwin 2P26 or 2P27 PACW 115kV	PF
1200	P2-3: Merwin 2P6 or 2P8 PACW 115kV	PF
1201	P2-3: Murrayhill V312 230kV	PF
1202	P2-3: Murrayhill V316 230kV	PF
1203	P2-3: Murrayhill V328 230kV	PF
1204	P2-3: Murrayhill W350 115kV	PF
1205	P2-3: Murrayhill W366 115kV	PF
1206	P2-3: Murrayhill W370 115kV	PF
1207	P2-3: Murrayhill W374 115kV	PF
1208	P2-3: Napavine 5226, 5229, or 5232 BPA 500kV	PF
1209	P2-3: Orenco W204 115kV	PF
1210	P2-3: Orenco W276 115kV	PF

No	Contingency	Power Flow (PF) or Post-Transient Power Flow (PT)
1211	P2-3: Ostrander 4432 BPA 500kV	PF
1212	P2-3: Ostrander 4442 BPA 500kV	PF
1213	P2-3: Ostrander 4445 BPA 500kV	PF
1214	P2-3: Ostrander 4448 BPA 500kV	PF
1215	P2-3: Ostrander 5139 BPA 500kV	PF
1216	P2-3: Parrish Gap 1M58, 1M61, or 1M63 PACW 230kV	PF
1217	P2-3: Paul 4532 BPA 500kV	PF
1218	P2-3: Paul 4536 BPA 500kV	PF
1219	P2-3: Paul 4542 BPA 500kV	PF
1220	P2-3: Paul 4544 BPA 500kV	PF
1221	P2-3: Paul 4550 BPA 500kV	PF
1222	P2-3: Paul 4554 BPA 500kV	PF
1223	P2-3: Paul 4818 BPA 500kV	PF
1224	P2-3: Pearl 4287 BPA 500kV	PF
1225	P2-3: Pearl A1165 BPA 230kV	PF
1226	P2-3: Pilot Butte 1D13 PACW 230kV	PF
1227	P2-3: Ponderosa A1815 BPA 230kV	PF
1228	P2-3: Ponderosa A1824 BPA 230kV	PF
1229	P2-3: Ponderosa A384, A395, or A398 BPA 230kV	PF
1230	P2-3: Port Westward V406 230kV	PF
1231	P2-3: Port Westward V416 230kV	PF
1232	P2-3: Port Westward V426 230kV	PF
1233	P2-3: Rosemont W122 115kV	PF
1234	P2-3: Rosemont W132 115kV	PF
1235	P2-3: Rosemont W242 115kV	PF
1236	P2-3: Rosemont W252 115kV	PF
1237	P2-3: Rosemont W362 115kV	PF
1238	P2-3: Roseway W132 115kV	PF
1239	P2-3: Roseway W142 115kV	PF
1240	P2-3: Ross A22 BPA 230kV	PF
1241	P2-3: Ross A24 BPA 230kV	PF
1242	P2-3: Ross A34 BPA 230kV	PF
1243	P2-3: Sherwood V278 230kV	PF
1244	P2-3: Shute W106 115kV	PF
1245	P2-3: Shute W334 115kV	PF
1246	P2-3: Shute W448 115kV	PF
1247	P2-3: Slatt 5003 BPA 500kV	PF
1248	P2-3: Slatt 5015 BPA 500kV	PF
1249	P2-3: Slatt 5018 BPA 500kV	PF
1250	P2-3: Slatt 5021 BPA 500kV	PF
1251	P2-3: Slatt 5043 BPA 500kV	PF
1252	P2-3: Slatt 5266 BPA 500kV	PF

No	Contingency	Power Flow (PF) or Post-Transient Power Flow (PT)
1253	P2-3: Slatt 5375 BPA 500kV	PF
1254	P2-3: St Marys V252 230kV	PF
1255	P2-3: St Marys V290 230kV	PF
1256	P2-3: St Marys W144 115kV	PF
1257	P2-3: St Marys W170 115kV	PF
1258	P2-3: St Marys W174 115kV	PF
1259	P2-3: St Marys W190 115kV	PF
1260	P2-3: St Marys W204 115kV	PF
1261	P2-3: St Marys W238 115kV	PF
1262	P2-3: St Marys W244 115kV	PF
1263	P2-3: St Marys W264 115kV	PF
1264	P2-3: St Marys W268 115kV	PF
1265	P2-3: St Marys W272 115kV	PF
1266	P2-3: St Marys W276 115kV	PF
1267	P2-3: St Marys W296 115kV	PF
1268	P2-3: St Marys W348 115kV	PF
1269	P2-3: St Marys W802 115kV	PF
1270	P2-3: St Marys WTBD1 115kV	PF
1271	P2-3: Summer Lake 4957, 4958, or 4959 BPA 500kV	PF
1272	P2-3: Sunset W102 115kV	PF
1273	P2-3: Sunset W114 115kV	PF
1274	P2-3: Sunset W118 115kV	PF
1275	P2-3: Sunset W128 115kV	PF
1276	P2-3: Swift 1P11 PACW 230kV	PF
1277	P2-3: Swift 1P24 CCPD 230kV	PF
1278	P2-3: Swift 1P35 CCPD 230kV	PF
1279	P2-3: Tonquin W202 or W210 115kV	PF
1280	P2-3: Tonquin W302 115kV	PF
1281	P2-3: Tonquin W306 115kV	PF
1282	P2-3: Tonquin W310 115kV	PF
1283	P2-3: Wautoma 5244 BPA 500kV	PF
1284	P2-3: Wautoma 5250 BPA 500kV	PF
1285	P2-3: Wautoma 5253 BPA 500kV	PF
1286	P2-3: Wautoma 5259 BPA 500kV	PF
1287	P2-3: Wautoma 5262 BPA 500kV	PF
1288	P2-3: West Union W122 115kV	PF
1289	P2-3: West Union W172 115kV	PF
1290	P2-3: West Union W242 115kV	PF
1291	P2-3: West Union W252 115kV	PF
1292	P2-3: West Union W332 115kV	PF
1293	P2-4: Allston Bus Sectionalizing Breaker BPA 230kV	PF
1294	P2-4: Alvey Bus Sectionalizing Breaker BPA 230kV	PF

No	Contingency	Power Flow (PF) or Post-Transient Power Flow (PT)
1295	P2-4: Canemah Bus Sectionalizing Breaker 57kV	PF
1296	P2-4: Dunns Corner Bus Sectionalizing Breaker 57kV	PF
1297	P2-4: Harrison Bus Sectionalizing Breaker PACW 115kV	PF
1298	P2-4: Keeler Bus Sectionalizing Breaker BPA 115kV	PF
1300	P2-4: Knott Bus Sectionalizing Breaker PACW 57kV	PF
1301	P2-4: Longview BPA Bus Sectionalizing Breaker 115kV	PF
1302	P2-4: Longview BPA Bus Sectionalizing Breaker 230kV	PF
1303	P2-4: Longview BPA-Longview Annex BPA Bus Sectionalizing Breaker 230kV	PF
1304	P2-4: Oak Grove Bus Sectionalizing Breaker 115kV	PF
1305	P2-4: Orenco Bus Sectionalizing Breaker 57kV	PF
1306	P2-4: Redmond Bus Sectionalizing Breaker BPA 115kV	PF
1307	P2-4: Redmond Bus Sectionalizing Breaker BPA 230kV	PF
1308	P2-4: Ross Bus Sectionalizing Breaker BPA 230kV	PF
1309	P2-4: Round Butte Bus Sectionalizing Breaker 230kV	PF
1310	P2-4: Santiam Bus Sectionalizing Breaker BPA 230kV	PF
1311	P2-4: St Helens Bus Sectionalizing Breaker 115kV	PF
1312	P2-4: Urban W602 Bus Sectionalizing Breaker 115kV	PF
1313	P2-4: Urban W606 Bus Sectionalizing Breaker 115kV	PF
1314	P2-4: Urban W662 Bus Sectionalizing Breaker 115kV	PF
1315	P2-4: Wacker Bus Sectionalizing Breaker 115kV	PF
1316	P4-2: Albina 2P14 PACW 115kV (Fault on Curtis line)	PF
1317	P4-2: Albina 2PNEW PACW 115kV (Fault on Knott PACW-St Johns BPA line)	PF
1318	P4-2: Allston B1900 BPA 115kV (Fault on Driscoll BPA line)	PF
1319	P4-2: Allston B1901 BPA 115kV (Fault on St Helens line)	PF
1320	P4-2: Banks B126 57kV (Fault on Cornelius line)	PF
1321	P4-2: Beaverton W102 115kV (Fault on Progress line)	PF
1322	P4-2: Beaverton W148 115kV (Fault on Tektronix line)	PF
1323	P4-2: Bethel V218 230kV (Fault on McLoughlin line)	PF
1324	P4-2: Boring B202, B208, B214, or B232 57kV (Fault on Dunns Corner line, Faraday line, Hogan South-Lents line, or River Mill line)	PF
1325	P4-2: Canemah W148 115kV (Fault on McLoughlin line)	PF
1326	P4-2: Carlton B127 BPA 115kV (Fault on McMinnville BPA line)	PF
1327	P4-2: Carlton B131 BPA 115kV (Fault on Forest Grove BPA-McMinnville BPA line)	PF
1328	P4-2: Carver W138 115kV (Fault on Gresham #3 line)	PF
1329	P4-2: Carver W480 115kV (Fault on Hogan South line)	PF
1330	P4-2: Chemawa B102 BPA 115kV (Fault on Oregon City BPA line)	PF
1331	P4-2: Chemawa B104 BPA 115kV (Fault on Salem BPA line)	PF
1332	P4-2: Chemawa L44 BPA 57kV (Fault on Salem line)	PF
1333	P4-2: Chemawa L55 BPA 57kV (Fault on St Louis line)	PF
1334	P4-2: Cornelius B122 57kV (Fault on Yamhill line)	PF

No	Contingency	Power Flow (PF) or Post-Transient Power Flow (PT)
1335	P4-2: Cornelius B134 57kV (Fault on Orenco #1 line)	PF
1336	P4-2: Cornelius B242 57kV (Fault on Orenco #2 line)	PF
1337	P4-2: Cornelius B364 57kV (Fault on Banks line)	PF
1338	P4-2: Culver W124 115kV (Fault on Bethel line)	PF
1339	P4-2: Culver W128 115kV (Fault on Mill Creek line)	PF
1340	P4-2: Dayton B102 57kV (Fault on Chemawa BPA line)	PF
1341	P4-2: Dayton B152 or B158 57kV (Fault on Sheridan or Yamhill lines)	PF
1342	P4-2: Driscoll A1264 BPA 230kV (Fault on Allston BPA-Clatsop BPA line)	PF
1343	P4-2: Dunns Corner B108 57kV (Fault on Brightwood line)	PF
1344	P4-2: Dunns Corner B114 57kV (Fault on Boring line)	PF
1345	P4-2: Faraday B166 57kV (Fault on Boring line)	PF
1346	P4-2: Faraday B176 57kV (Fault on River Mill line)	PF
1347	P4-2: Forest Grove B1286 BPA 115kV (Fault on McMinnville BPA line)	PF
1348	P4-2: Forest Grove B1287 BPA 115kV (Fault on Tillamook BPA line)	PF
1349	P4-2: Glendoveer W218 115kV (Fault on Tabor line)	PF
1350	P4-2: Glendoveer W224 or W236 115kV (Fault on Blue Lake or Gresham lines)	PF
1351	P4-2: Gresham W126 115kV (Fault on Glendoveer line)	PF
1352	P4-2: Gresham W132 115kV (Fault on Bell line)	PF
1353	P4-2: Gresham W182 115kV (Fault on Holgate line)	PF
1354	P4-2: Harrison 2P314 PACW 115kV (Fault on Holladay PACW line)	PF
1355	P4-2: Hogan South B106 or B118 57kV (Fault on Boring-Lents or Tabor lines)	PF
1356	P4-2: Hogan South B112 57kV (Fault on Dunns Corner line)	PF
1357	P4-2: Hogan W224 115kV (Fault on Carver line)	PF
1358	P4-2: Hogan W236 115kV (Fault on McGill line)	PF
1359	P4-2: Leland B102 57kV (Fault on Molalla line)	PF
1360	P4-2: Lents B114 57kV (Fault on Tabor line)	PF
1361	P4-2: Lents B126 or B134 57kV (Fault on Sellwood line or Boring-Hogan South line)	PF
1362	P4-2: Market W104 115kV (Fault on Bethel line)	PF
1363	P4-2: Market W216 115kV (Fault on Chemawa BPA line)	PF
1364	P4-2: McLoughlin V210 230kV (Fault on Bethel line)	PF
1365	P4-2: McLoughlin V232 230kV (Fault on Pearl BPA-Sherwood line)	PF
1366	P4-2: McLoughlin W102 115kV (Fault on Faraday line)	PF
1367	P4-2: McLoughlin W110 115kV (Fault on Oak Grove line)	PF
1368	P4-2: McLoughlin W126 115kV (Fault on Canemah line)	PF
1369	P4-2: McLoughlin W162 115kV (Fault on Sellwood line)	PF
1370	P4-2: McMinnville B1310 BPA 115kV (Fault on Carlton BPA line)	PF
1371	P4-2: McMinnville B1314 BPA 115kV (Fault on Dayton-Newberg line)	PF
1372	P4-2: McMinnville B381 BPA 115kV (Fault on Walnut City MW&L line)	PF
1373	P4-2: McMinnville B666 BPA 115kV (Fault on Forest Grove BPA line)	PF

No	Contingency	Power Flow (PF) or Post-Transient Power Flow (PT)
1374	P4-2: Meridian W246 115kV (Fault on Tonquin line)	PF
1375	P4-2: Mill Creek W108 115kV (Fault on Hillcrest line)	PF
1376	P4-2: Mill Creek W202 115kV (Fault on Culver line)	PF
1377	P4-2: Molalla B272 57kV (Fault on Mt Angel line)	PF
1378	P4-2: Monitor B108 57kV (Fault on Mt Angel line)	PF
1379	P4-2: Mt Angel B214 or B220 57kV (Fault on Molalla or Monitor lines)	PF
1380	P4-2: Newberg W216, W228, or W238 115kV (Fault on Sherwood line, Springbrook line, or Dayton-McMinnville BPA line)	PF
1381	P4-2: North Marion B102 57kV (Fault on Monitor line)	PF
1382	P4-2: North Marion B108 57kV (Fault on St Louis line)	PF
1383	P4-2: North Marion B126 57kV (Fault on Sullivan line)	PF
1384	P4-2: Northern WTBD1 115kV (Fault on Curtis line)	PF
1385	P4-2: Oregon City B254 BPA 115kV (Fault on Chemawa BPA line)	PF
1386	P4-2: Orenco B104 57kV (Fault on Cornelius #1 line)	PF
1387	P4-2: Orenco B126 57kV (Fault on Cornelius #2 line)	PF
1388	P4-2: Progress W206 115kV (Fault on West Portland line)	PF
1389	P4-2: Redmond A265 BPA 230kV (Fault on Big Eddy BPA line)	PF
1390	P4-2: Redmond B1556 BPA 115kV (Fault on Brasada CEC line)	PF
1391	P4-2: River Mill B302 or B310 57kV (Fault on Boring or Faraday lines)	PF
1392	P4-2: River Road PCB1 CPU 115kV (Fault on Hazel Dell PACW-St Johns SS PACW line)	PF
1393	P4-2: Rivergate W122 115kV (Fault on Harborton #2 line)	PF
1394	P4-2: Salem B102 57kV (Fault on Bethel line)	PF
1395	P4-2: Salem B54 BPA 115kV (Fault on Chemawa BPA line)	PF
1396	P4-2: Salem B60 BPA 115kV (Fault on Albany BPA #1 line)	PF
1397	P4-2: Sellwood W252 115kV (Fault on Raleigh Hills line)	PF
1398	P4-2: Sellwood W258 115kV (Fault on Urban-West Portland line)	PF
1399	P4-2: Sellwood W276 115kV (Fault on McLoughlin line)	PF
1400	P4-2: Sellwood W290 115kV (Fault on Carver line)	PF
1401	P4-2: Sheridan B124 57kV (Fault on Dayton line)	PF
1402	P4-2: Sherwood W108 115kV (Fault on Newberg line)	PF
1403	P4-2: Springbrook W130 115kV (Fault on Newberg line)	PF
1404	P4-2: Springbrook W138 115kV (Fault on Sherwood line)	PF
1405	P4-2: St Helens W102 115kV (Fault on St Johns BPA line)	PF
1406	P4-2: St Helens W186 115kV (Fault on Allston BPA line)	PF
1407	P4-2: St Johns B40 BPA 115kV (Fault on St Helens position)	PF
1408	P4-2: St Johns B80 BPA 115kV (Fault on Albina PACW-Knott PACW line)	PF
1409	P4-2: St Johns SS 2P57 PACW 115kV (Fault on Knott PACW line)	PF
1410	P4-2: St Johns SS 2P60 PACW 115kV (Fault on Hazel Dell PACW line)	PF
1411	P4-2: Tabor W160 115kV (Fault on Blue Lake line)	PF
1412	P4-2: Tabor W166 115kV (Fault on Alder line)	PF
1413	P4-2: Tabor W238 115kV (Fault on Glendoveer line)	PF

No	Contingency	Power Flow (PF) or Post-Transient Power Flow (PT)
1414	P4-2: Tektronix W132 (Fault on St Marys line) 115kV	PF
1415	P4-2: Troutdale 2P113 PACW 115kV (Fault on Knott PACW line)	PF
1416	P4-2: Troutdale A118 BPA 230kV (Fault on Big Eddy BPA line)	PF
1417	P4-2: Urban W156 115kV (Fault on Sellwood-West Portland line)	PF
1418	P4-2: West Portland W202 115kV (Fault on Canyon line)	PF
1419	P4-2: West Portland W208 115kV (Fault on Sellwood-Urban line)	PF
1420	P4-2: West Portland W236 115kV (Fault on Progress line)	PF
1421	P4-2: West Portland W246 115kV (Fault on King City line)	PF
1422	P4-2: Wilsonville W172 115kV (Fault on Sherwood line)	PF
1423	P4-3: Bethel B226 57kV (Fault on WBR3)	PF
1424	P4-3: Canemah W140 or W162 115kV (Fault on WBR1-2-3 or WBR4-5-6)	PF
1425	P4-3: Carlton B129 BPA 115kV (Fault on Carlton BPA Transformer)	PF
1426	P4-3: Leland B110 57kV (Fault on BR1)	PF
1427	P4-3: River Mill B314 or B316 57kV (Fault on BK9 or BK10)	PF
1428	P4-3: Sellwood W268 115kV (Fault on WBR1)	PF
1429	P7: Ashe BPA-Marion BPA 500kV & Ashe BPA-Slatt BPA 500kV	PF
1430	P7: Ashe BPA-Marion BPA 500kV & Buckley BPA-Slatt BPA 500kV	PF
1431	P7: Bethel-Santiam BPA 230kV & Chemawa BPA-Santiam BPA 230kV	PF
1432	P7: Big Eddy BPA-Chemawa BPA 230kV & Big Eddy BPA-Troutdale BPA 230kV	PF
1433	P7: Big Eddy BPA-Knight BPA 500kV & McNary BPA-Ross BPA 345kV	PF
1434	P7: Blue Lake-Fairview 115kV & Blue Lake-Glendoveer 115kV	PF
1435	P7: Blue Lake-Gresham 230kV & Blue Lake-Kelly Butte 115kV	PF
1436	P7: Blue Lake-Troutdale BPA #1 & #2 230kV	PF
1437	P7: Boring-Faraday 57kV & Boring-River Mill 57kV	PF
1438	P7: Boring-Faraday 57kV & Faraday-River Mill 57kV	PF
1439	P7: Butler-St Marys 115kV & Century-Orenco 115kV	PF
1440	P7: Captain Jack BPA-Ponderosa BPA-Grizzly BPA 500kV & Captain Jack BPA-Malin BPA #1 500kV	PF
1441	P7: Carlton BPA-McMinnville BPA 115kV & Forest Grove BPA-McMinnville BPA 115kV	PF
1442	P7: Carlton BPA-Sherwood 230kV & Newberg-Sherwood 115kV	PF
1443	P7: Carlton BPA-Tillamook BPA 230kV & Forest Grove BPA-Tillamook BPA 115kV	PF
1444	P7: Carver-Gresham #3 115kV & Carver-Hogan South 115kV	PF
1445	P7: Century-Orenco 115kV & St Marys-West Union 115kV	PF
1446	P7: Chehalis BPA-Longview BPA 230kV & Lexington BPA-Longview BPA 230kV	PF
1447	P7: Chemawa BPA-Indian 115kV & Chemawa BPA-Claxtar 57kV	PF
1448	P7: Chemawa BPA-Salem BPA #1 230kV & Chemawa BPA-Salem BPA #2 115kV	PF
1449	P7: Cornelius-Forest Grove BPA 115kV & Banks-Cornelius 57kV	PF

No	Contingency	Power Flow (PF) or Post-Transient Power Flow (PT)
1450	P7: Evergreen-Harborton 230kV & Harborton-St Marys 230kV	PF
1451	P7: Evergreen-Sunset 115kV & Shute-Sunset 115kV	PF
1452	P7: Gresham-Troutdale PACW #1 & #2 230kV	PF
1453	P7: Harborton-Rivergate #1 230kV & Harborton-Kelley Point 115kV	PF
1454	P7: Harborton-St Marys 230kV & St Marys-Cedar Hills 115kV	PF
1455	P7: Harborton-Trojan #1 & #2 230kV	PF
1456	P7: Keeler BPA-St Johns BPA 115kV & St Helens-St Johns BPA 115kV	PF
1457	P7: Keeler BPA-St Marys 230kV & St Marys-West Union 115kV	PF
1458	P7: Market-Indian 115kV & Chemawa BPA-Claxtar 57kV	PF
1459	P7: Market-Indian 115kV & Chemawa BPA-McClain 57kV	PF
1460	P7: McLoughlin-Pearl-Sherwood 230kV& McLoughlin-Tonquin 115kV	PF
1461	P7: Murrayhill-St Marys 230kV & Murrayhill-Reedville 115kV	PF
1462	P7: North Bonneville BPA-Ross BPA #1 & #2 230kV	PF
1463	P7: Orenco-St Marys #1 & #2 115kV	PF
1464	P7: Port Westward-Trojan #1 & #2 230kV	PF
1465	Extreme Event: Alder Yard - 115kV	PF
1466	Extreme Event: Allston BPA Sub to Trojan Sub Corridor	PF
1467	Extreme Event: Allston BPA Yard - 500kV	PF
1468	Extreme Event: Barrows Rd to Beef Bend Rd Corridor	PF
1469	Extreme Event: Beef Bend Rd to Sherwood Corridor	PF
1470	Extreme Event: Bell Yard - 115kV	PF
1471	Extreme Event: Bethel Yard - 115kV	PF
1472	Extreme Event: Blue Lake Yard - 115kV	PF
1473	Extreme Event: Blue Lake Yard - 230kV	PF
1474	Extreme Event: Brookwood Yard - 115kV	PF
1475	Extreme Event: Butler Yard - 115kV	PF
1476	Extreme Event: Canyon Yard - 115kV	PF
1477	Extreme Event: Carver Yard - 115kV	PF
1478	Extreme Event: Carver Yard - 230kV	PF
1479	Extreme Event: Curtis Yard - 115kV	PF
1480	Extreme Event: East of Ostrander BPA Sub Corridor	PF
1481	Extreme Event: East of Sherwood Sub Corridor	PF
1482	Extreme Event: Evergreen Yard - 115kV	PF
1483	Extreme Event: Evergreen Yard - 230kV	PF
1484	Extreme Event: Faraday Yard - 115kV	PF
1485	Extreme Event: Glisan Yard - 115kV	PF
1486	Extreme Event: Gresham Yard - 115kV	PF
1487	Extreme Event: Harborton to Rivergate Corridor	PF
1488	Extreme Event: Harborton Yard - 115kV	PF
1489	Extreme Event: Harborton Yard - 230kV	PF
1490	Extreme Event: Harrison Yard - 115kV	PF
1491	Extreme Event: Helvetia Yard - 115kV	PF

No	Contingency	Power Flow (PF) or Post-Transient Power Flow (PT)
1492	Extreme Event: Hillcrest Yard - 115kV	PF
1493	Extreme Event: Horizon Yard - 230kV	PF
1494	Extreme Event: Hwy 30 to North Bethany Corridor	PF
1495	Extreme Event: Keeler to Neakahnie Ave Corridor	PF
1496	Extreme Event: Keeler to Springville Jct Corridor	PF
1497	Extreme Event: Knott PACW Yard - 115kV	PF
1498	Extreme Event: Lincoln PACW Yard - 115kV	PF
1500	Extreme Event: Marquam Yard - 115kV	PF
1501	Extreme Event: McGill Yard - 115kV	PF
1502	Extreme Event: McLoughlin to Thayer Rd Corridor	PF
1503	Extreme Event: McLoughlin Yard - 115kV	PF
1504	Extreme Event: McLoughlin Yard - 230kV	PF
1505	Extreme Event: McNamee Rd to Harborton Corridor	PF
1506	Extreme Event: Murrayhill Yard - 115kV	PF
1507	Extreme Event: Murrayhill Yard - 230kV	PF
1508	Extreme Event: North of Allston BPA Sub Corridor	PF
1509	Extreme Event: North of Gresham Corridor	PF
1511	Extreme Event: North of Murrayhill Corridor	PF
1512	Extreme Event: North of St Marys Corridor	PF
1513	Extreme Event: Oregon St to Tonquin Rd Corridor	PF
1514	Extreme Event: Ostrander BPA Yard - 500kV	PF
1515	Extreme Event: Pearl BPA Yard - 500kV	PF
1516	Extreme Event: Pearl Sub to Advance Rd Corridor	PF
1517	Extreme Event: Redland to Ostrander BPA Corridor	PF
1518	Extreme Event: Rosemont Yard - 115kV	PF
1519	Extreme Event: Roseway Yard - 115kV	PF
1520	Extreme Event: Sherwood Yard - 115kV	PF
1521	Extreme Event: Sherwood Yard - 230kV	PF
1522	Extreme Event: Shute Yard - 115kV	PF
1523	Extreme Event: South of Allston BPA Sub Corridor	PF
1525	Extreme Event: South of McLoughlin to Redland Corridor	PF
1526	Extreme Event: St Marys Yard - 115kV	PF
1527	Extreme Event: St Marys Yard - 230kV	PF
1528	Extreme Event: Station E Yard - 115kV	PF
1529	Extreme Event: Sunset Yard - 115kV	PF
1530	Extreme Event: Trojan to Goble Corridor	PF
1531	Extreme Event: Trojan Yard - 230kV	PF
1532	Extreme Event: Troutdale PACW Yard - 115kV	PF
1533	Extreme Event: Troutdale PACW Yard - 230kV	PF
1534	Extreme Event: West Union Yard - 115kV	PF

A list of additional contingencies to be simulated during the power flow analysis with the 2024 Light Spring base case are provided.

Table 3-5 2024 Light Spring Additional Contingencies – Power Flow Analysis

No	Contingency	Power Flow (PF) or Post-Transient Power Flow (PT)
1	P6.1_ Keeler -Pearl 500 & Murray Hill – St. Marys 230kV line	PF
2	P6.1_ Keeler - Pearl 500 & Murray Hill – Sherwood No.1 230kV line	PF
3	P6.1_ Keeler - Pearl 500 & Murray Hill – Sherwood No.2 230kV line	PF
4	P6.1_ Keeler - Pearl 500 & Pearl – Sherwood 230kV line	PF
5	P6.1_ Marion-Pearl 500 & Ostrander – Pearl 500kV line	PF

A list of contingencies to be simulated during the transient stability analysis. RAS will be included as identified in the following table.

Table 3-4 Contingencies - Transient Stability Analysis

No	Contingency
1	P1.2_HARBORTON- STMARYS_230
2	P1.2_HARBORTON- TROJAN_NO_1_230
3	P1.2_RIVERGATE- HARBORTON_230
4	P1.2_HARBORTON- EVERGREEN_230
5	P1.2_ASHE-MARION_500
6	P1.2_ASHE-SLATT_500
7	P1.2_BIGEDDY-JOHNDAY_500_1
8	P1.2_BIGEDDY-KNIGHT_500
9	P1.2_BIGEDDY-OSTRNDER_500
10	P1.2_BUCKLEY-MARION_500
11	P1.2_JOHNDAY-MARION_500
12	P1.2_KEELER-PEARL_500
13	P1.2_MARION-PEARL_500
14	P1.2_OSTRNDER-KNIGHT_500
15	P1.2_OSTRNDER-PEARL_500
16	P1.2_TROUTDAL- OSTRNDER_500
17	P1.2_RAVER-PAUL_500
18	P1.2_WAUTOMA-KNIGHT_500
19	P1.2_WAUTOMA-ROCK CK_500
20	P1.2_MCNARY-ROSS_345
21	P1.2_BIGEDDY-PARKDALE_230
22	P1.2_TROUTD E- PARKDALE_230
23	P1.2_NBONVL W-ROSS_230 No.1
24	P1.2_N.BONNVL- LITLBUCK_230
25	P1.2_BIGEDDY2-CHEMAWA_230
26	P1.2_BIGEDDY3-MCLOUGLN_230
27	P1.2_BETHEL-ROUNDB N_230
28	P1.2_JONESCYN-SANTIAM WEST_230
29	P1.5_CRTP-VSC-HVDC Outage
30	P1.5_PDCI-NS-monopolar
31	P4.2_Keeler Breaker Failure
32	P7.1_Malin - Round Mountain 500kV #1 and #2 Lines (RAS)
33	P7.1_Trojan-Harborton No.1 and No.2 230 kV Lines
34	P7.2_PDCI bi-pole Outage (w/ RAS)
	Extreme_Palo Verde Generation – Trip Two Units (w/ RAS)†

† NERC Extreme Event

APPENDIX 4 – CRTP VSC-HVDC PROJECT PLAN OF SERVICE

Listed below are the major elements of the Plan of Service (POS) for the CRTP VSC-HVDC Project with a 1,100 MW Planned Rating east to west.

1. DC Terminals
   a. Rectifier connecting to the Big Eddy 500 kV substation.
   b. Inverter connecting to the Harborton 230 kV substation.
   c. Voltage Source Converter-based HVDC (symmetrical monopole) converter rated for 1,100 MW at the inverter end, (+/-371 MVAr at Big Eddy and +/-363 MVAr at Harborton)

2. CRT HVDC Transmission Line
   a. 105 miles of ±320 kV, 1,100 MW symmetrical monopole (single pole)
      1. Approximately 5 miles of DC land cable, 3000 mm2 AL XLPE
      2. Approximately 100 miles of DC submarine cable, 2000 mm2 CU XLPE

APPENDIX 5 – PROJECTS IN PATH RATING PROCESS

Listed below are projects in Phase 2 and Phase 3 of the WECC Path Rating process taken from the WECC Path Rating Process Logbook dated May 19, 2021, unless otherwise noted.

Project Name	Project Sponsor
Phase 2 Projects - Active	
Cross-Tie Transmission Project	TransCanyon
SWIP-North Project	LS Power & Great Basin Transmission
SWIP-South Project	LS Power & Great Basin Transmission
Path 46 HVDC Uprate Project	SCE/LADWP
Phase 2 Projects – Inactive	
None	
Phase 3 Projects – Active	
Hassayampa – N. Gila #2 (HANG2) Transmission Project (Path 49)	APS
TOT 1A (Path 30) Limit Calculation Update Project	WAPA
SunZia Southwest Transmission Project	Southwestern Power Group II
Southline Transmission Project	Southline Transmission Project, LLC
TOT3 Wayne Child Project	TSGT
TransWest Express Project†	TransWest Express LLC
TransWest Express AC and DC Project	TransWest Express LLC
North Gila-Imperial Valley #2 Project	ITC Grid Development and Southwest Transmission Partners
Path 61 Uprate	LADWP
Increase Path 46 West of Colorado River (WOR)	SCE/LADWP
Gateway West – Aeolus West, Bridger/Anticline West and Path C Projects	PACE
Gateway South – Aeolus South Project	PACE
Gateway South – TOT 2B/2C Project	PACE
Gateway West – TOT 4A Project	PACE
Gateway West – Borah West, Midpoint West & Bridger 2400 MW Upgrade Projects	PACE
Phase 3 – Pending and Inactive	
TotBeast with Hemingway – Boardman 500 kV	IPC
Hemingway to Boardman Transmission Project	IPC
Walla Walla-McNary Transmission Project	Pacific Power

† This Project will not be modeled in studies; since, the TWE AC and DC Project alternative is most current.

APPENDIX 6 – TEN PERCENT TEST RESULTS

Listed below are Ten Percent Test results for loss of the CRTP DC line for the non-simultaneous base case with east to west and west to east flow.

Table 6-1 CRTP Project (East to West Flow), Ten Percent Test Results

NUM	NAME	Post-Con 'Direction of + Flow	Pre-Con Flow	Post-Con Flow	Flow Change	Percent of Path Rating	Path Rating (+)	Path Rating (-)
1	ALBERTA - BRITISH COLUMBIA	W2E	-400.5	-398.7	1.8	-0.2	1000	-1200
2	ALBERTA - SASKATCHEWAN	W2E	0.1	0.1	0	0.0	150	-150
3	NORTHWEST - CANADA	N2S	-1998	-1999.4	-1.4	0.0	3000	-3150
4	WEST OF CASCADES - NORTH	E2W	4240.2	4464.3	224.1	2.2	10200	-10200
5	WEST OF CASCADES - SOUTH	E2W	4397.2	5212.4	815.2	11.3	7200	-7200
6	WEST OF HATWAI	E2W	-61.6	-57.4	4.2	0.1	4277	0
8	MONTANA - NORTHWEST	E2W	-69.4	-63.4	6	0.3	2200	-1350
14	IDAHO - NORTHWEST	W2E	-1182.9	-1180	2.9	0.1	3400	-2250
15	MIDWAY - LOS BANOS	S2N	-1641.5	-1639.3	2.2	0.0	4800	-2000
16	IDAHO - SIERRA	N2S	264.6	264.8	0.2	-0.1	500	-360
17	BORAH WEST	E2W	233.8	235	1.2	0.0	4450	-1600
18	MONTANA - IDAHO	N2S	258.1	255.9	-2.2	-0.6	383	-256
19	BRIDGER WEST	E2W	1508.3	1509.8	1.5	0.1	2400	-600
20	PATH C	N2S	905.9	904.9	-1	0.1	1600	-1250
24	PG&E - SPP	E2W	31.7	31.7	0	0.0	160	-150
25	PACIFICORP/PG&E 115 KV INTERCON.	N2S	60.5	60	-0.5	-0.5	100	-45
26	NORTHERN - SOUTHERN CALIFORNIA	N2S	710.7	708.5	-2.2	-0.1	4000	-3000
27	IPP DC LINE	N2S	701.8	701.8	0	0.0	2400	-1400
28	INTERMOUNTAIN - MONA 345 KV	E2W	39.2	39.1	-0.1	0.0	1400	-1200
29	INTERMOUNTAIN - GONDER 230 KV	E2W	71.9	72.1	0.2	0.1	200	0
30	TOT 1A	E2W	199.2	200.7	1.5	0.2	650	0
31	TOT 2A	N2S	160.3	161.8	1.5	0.2	690	0
32	PAVANT, INTRMTN - GONDER 230 KV	E2W	159	159.3	0.3	0.1	440	-235
33	BONANZA WEST	E2W	-408.3	-409.4	-1.1	-0.1	785	0
35	TOT 2C	N2S	173.9	174.2	0.3	-0.1	600	-580
36	TOT 3	N2S	1057.2	1061.3	4.1	0.2	1680	0
37	TOT 4A	NE2SW	189.2	189.7	0.5	0.1	810	0
38	TOT 4B	SE2NW	-99.9	-98.8	1.1	0.2	680	0
39	TOT 5	W2E	375.2	374.2	-1	-0.1	1680	0
40	TOT 7	N2S	260.7	261.1	0.4	0.0	890	0
41	SYLMAR - SCE	N2S	177.5	177.8	0.3	0.0	1600	-1600
42	IID - SCE	E2W	263.8	263.8	0	0.0	600	0
45	SDG&E - CFE	S2N	-46.7	-46.7	0	0.0	600	-800
46	WEST OF COLORADO RIVER (WOR)	E2W	5882.6	5884.7	2.1	0.0	11200	-11200

NUM	NAME	Post-Con 'Direction of + Flow	Pre-Con Flow	Post-Con Flow	Flow Change	Percent of Path Rating	Path Rating (+)	Path Rating (-)
47	SOUTHERN NEW MEXICO (NM1)	N2S	149	149	0	0.0	1048	-1048
48	NORTHERN NEW MEXICO (NM2)	N2S	1702.8	1702.8	0	0.0	1970	-1970
49	EAST OF COLORADO RIVER (EOR)	E2W	1325	1326.6	1.6	0.0	10100	0
52	SILVER PEAK - CONTROL 55 KV	E2W	-0.5	-0.5	0	0.0	17	-17
54	CORONADO - SILVER KING - KYRENE	N2S	556.4	556.6	0.2	0.0	1494	0
55	BROWNLEE EAST	W2E	1749.5	1745.8	-3.7	-0.2	1915	0
58	ELDORADO - MEAD 230 KV LINES	N2S	21.9	21.9	0	0.0	1140	-1140
59	WALC BLYTHE - SCE BLYTHE 161 KV	E2W	69.2	69.2	0	0.0	218	0
60	INYO - CONTROL 115 KV TIE	E2W	-22.9	-22.9	0	0.0	56	-56
61	LUGO - VICTORVILLE 500 KV LINE	E2W	1019.5	1020.1	0.6	0.0	2400	-900
62	ELDORADO - MCCULLOUGH 500 KV	W2E	333	333.1	0.1	0.0	2598	-2598
65	PACIFIC DC INTERTIE (PDCI)	N2S	3220	3220	0	0.0	3220	-3100
66	COI	N2S	4386.5	4384.6	-1.9	0.0	4800	-3675
71	SOUTH OF ALLSTON	N2S	2678.4	2896.2	217.8	**19.5**	3980	-1115
75	MIDPOINT - SUMMER LAKE	E2W	-524.9	-526	-1.1	0.2	1500	-550
76	ALTURAS PROJECT	N2S	0	0	0	0.0	300	-300
77	CRYSTAL - ALLEN	S2N	0	0	0	0.0	950	0
78	TOT 2B1	N2S	-225.8	-225.9	-0.1	0.0	600	-600
79	TOT 2B2	N2S	50.1	50.2	0.1	0.0	265	-300
80	MONTANA SOUTHEAST	S2N	203.9	198.9	-5	-0.8	600	-600
81	SNTI-S.NEVADA TRAN INTERFACE	S2N (Imp)	-1391.4	-1391.3	0.1	0.0	4533	-3790
82	TOTBEAST	W2E	2274.5	2271.8	-2.7	-0.1	3515	0
83	MATL	S2N	-54.8	-56.6	-1.8	-0.6	325	-300
86	WEST OF JOHN DAY	E2W	3112.1	2739.9	-372.2	-7.8	4760	0
87	WEST OF MCNARY	E2W	3075.4	3035.5	-39.9	-0.8	4925	0
88	WEST OF SLATT	E2W	3564	3494.9	-69.1	-1.5	4760	0

Table 6-2 CRTP Project (West to East Flow), Ten Percent Test Results

NUM	NAME	Post-Con 'Direction of + Flow	Pre-Con Flow	Post-Con Flow	Flow Change	Percent of Path Rating	Path Rating (+)	Path Rating (-)
1	ALBERTA - BRITISH COLUMBIA	W2E	-394.2	-396.5	-2.3	0.2	1000	-1200
2	ALBERTA - SASKATCHEWAN	W2E	0.1	0.1	0	0.0	150	-150
3	NORTHWEST - CANADA	N2S	-2004.7	-2002.9	1.8	0.1	3000	-3150
4	WEST OF CASCADES - NORTH	E2W	4629.1	4400.1	-229	-2.2	10200	-10200
5	WEST OF CASCADES - SOUTH	E2W	5866.7	5041	-825.7	**-11.5**	7200	-7200
6	WEST OF HATWAI	E2W	-169.5	-181	-11.5	-0.3	4277	0
8	MONTANA - NORTHWEST	E2W	21.9	9.1	-12.8	-0.6	2200	-1350
14	IDAHO - NORTHWEST	W2E	-1274.6	-1291.6	-17	-0.5	3400	-2250
15	MIDWAY - LOS BANOS	S2N	-1649.5	-1660.9	-11.4	-0.2	4800	-2000
16	IDAHO - SIERRA	N2S	268.1	267.3	-0.8	0.2	500	-360
17	BORAH WEST	E2W	222.4	216.2	-6.2	-0.1	4450	-1600
18	MONTANA - IDAHO	N2S	221.9	225.3	3.4	0.9	383	-256
19	BRIDGER WEST	E2W	1494.7	1487.9	-6.8	-0.3	2400	-600
20	PATH C	N2S	917.4	921.2	3.8	-0.3	1600	-1250
24	PG&E - SPP	E2W	30.7	31.1	0.4	-0.3	160	-150
25	PACIFICORP/PG&E 115 KV INTERCON.	N2S	67.9	68.4	0.5	0.5	100	-45
26	NORTHERN - SOUTHERN CALIFORNIA	N2S	720.5	731.8	11.3	0.3	4000	-3000
27	IPP DC LINE	N2S	701.8	701.8	0	0.0	2400	-1400
28	INTERMOUNTAIN - MONA 345 KV	E2W	39.2	40.1	0.9	0.1	1400	-1200
29	INTERMOUNTAIN - GONDER 230 KV	E2W	71.9	71	-0.9	-0.5	200	0
30	TOT 1A	E2W	193.6	187.5	-6.1	-0.9	650	0
31	TOT 2A	N2S	153.5	147	-6.5	-0.9	690	0
32	PAVANT, INTRMTN - GONDER 230 KV	E2W	159	157.6	-1.4	-0.3	440	-235
33	BONANZA WEST	E2W	-403.3	-398.7	4.6	0.6	785	0
35	TOT 2C	N2S	172.5	170.5	-2	0.3	600	-580
36	TOT 3	N2S	1043.7	1026.2	-17.5	-1.0	1680	0
37	TOT 4A	NE2SW	171.9	167.8	-4.1	-0.5	810	0
38	TOT 4B	SE2NW	-82.2	-84.2	-2	-0.3	680	0
39	TOT 5	W2E	379.7	383.8	4.1	0.2	1680	0
40	TOT 7	N2S	259.3	257.6	-1.7	-0.2	890	0
41	SYLMAR - SCE	N2S	174.3	172.8	-1.5	-0.1	1600	-1600
42	IID - SCE	E2W	263.9	263.9	0	0.0	600	0
45	SDG&E - CFE	S2N	-46.7	-46.7	0	0.0	600	-800
46	WEST OF COLORADO RIVER (WOR)	E2W	5869.1	5858.6	-10.5	-0.1	11200	-11200
47	SOUTHERN NEW MEXICO (NM1)	N2S	149	149	0	0.0	1048	-1048
48	NORTHERN NEW MEXICO (NM2)	N2S	1702.9	1702.9	0	0.0	1970	-1970
49	EAST OF COLORADO RIVER (EOR)	E2W	1315.1	1307.3	-7.8	-0.1	10100	0

NUM	NAME	Post-Con 'Direction of + Flow	Pre-Con Flow	Post-Con Flow	Flow Change	Percent of Path Rating	Path Rating (+)	Path Rating (-)
52	SILVER PEAK - CONTROL 55 KV	E2W	-0.3	-0.3	0	0.0	17	-17
54	CORONADO - SILVER KING - KYRENE	N2S	555.5	554.2	-1.3	-0.1	1494	0
55	BROWNLEE EAST	W2E	1631.8	1639.2	7.4	0.4	1915	0
58	ELDORADO - MEAD 230 KV LINES	N2S	22.2	22.4	0.2	0.0	1140	-1140
59	WALC BLYTHE - SCE BLYTHE 161 KV	E2W	69.2	69.2	0	0.0	218	0
60	INYO - CONTROL 115 KV TIE	E2W	-22.8	-22.8	0	0.0	56	-56
61	LUGO - VICTORVILLE 500 KV LINE	E2W	1013.7	1010.7	-3	-0.1	2400	-900
62	ELDORADO - MCCULLOUGH 500 KV	W2E	332.3	331.7	-0.6	0.0	2598	-2598
65	PACIFIC DC INTERTIE (PDCI)	N2S	3220	3220.1	0.1	0.0	3220	-3100
66	COI	N2S	3937.6	3950	12.4	0.3	4800	-3675
71	SOUTH OF ALLSTON	N2S	2820.3	2598	-222.3	**-19.9**	3980	-1115
75	MIDPOINT - SUMMER LAKE	E2W	-718.8	-728	-9.2	1.7	1500	-550
76	ALTURAS PROJECT	N2S	67.6	68.8	1.2	-0.4	300	-300
77	CRYSTAL - ALLEN	S2N	0	0	0	0.0	950	0
78	TOT 2B1	N2S	-225.8	-225	0.8	-0.1	600	-600
79	TOT 2B2	N2S	49.9	49.4	-0.5	-0.2	265	-300
80	MONTANA SOUTHEAST	S2N	142.9	153.7	10.8	1.8	600	-600
81	SNTI-S.NEVADA TRAN INTERFACE	S2N (Imp)	-1391.7	-1392.2	-0.5	0.0	4533	-3790
82	TOTBEAST	W2E	2350.6	2367.1	16.5	0.5	3515	0
83	MATL	S2N	-61.3	-59.1	2.2	0.7	325	-300
86	WEST OF JOHN DAY	E2W	2376.3	2736.9	360.6	7.6	4760	
87	WEST OF MCNARY	E2W	2767.5	2803.7	36.2	0.7	4925	
88	WEST OF SLATT	E2W	3222.7	3291.6	68.9	1.4	4760	

Attachment 13. PNUCC Northwest Regional Forecast of Power Loads and Resource

Northwest Regional Forecast

of Power Loads and Resources

August 2023 through July 2033

PNUCC

May 2023

Special thanks to PNUCC System Planning Committee members and utility staff who provided us with this information.

Electronic copies of this report are available on the

PNUCC website

www.PNUCC.org

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2023 Northwest Regional Forecast

Executive Summary

The *Northwest Regional Forecast* (*Forecast*) has provided a consistent assessment of the region's electric power system for over 70 years. By examining utility-reported information, the *Forecast* provides a utility perspective on trends in the evolving power system, such as changes in demand, resources and emerging technologies for meeting future electric power needs.

This year's snapshot is particularly significant given recent record-breaking winter and summer peaks, which have utilities focused on the need for sufficient capacity to meet a rising demand for electricity on top of the transition to clean energy. The *2023 Forecast* shows Northwest utilities are anticipating a significant increase in loads over the next five years and working to meet a growing demand for electricity with renewable resources, energy storage and dependable capacity.

Loads Show Up with More Certainty

The 2023 *Forecast* reflects accelerated and steeper regional load growth compared to previous years. Much of this load growth is attributed to more certainty in prospective new industrial loads over the next five years.

Figure 1: Load Forecasts Comparison 2023 vs. 2022

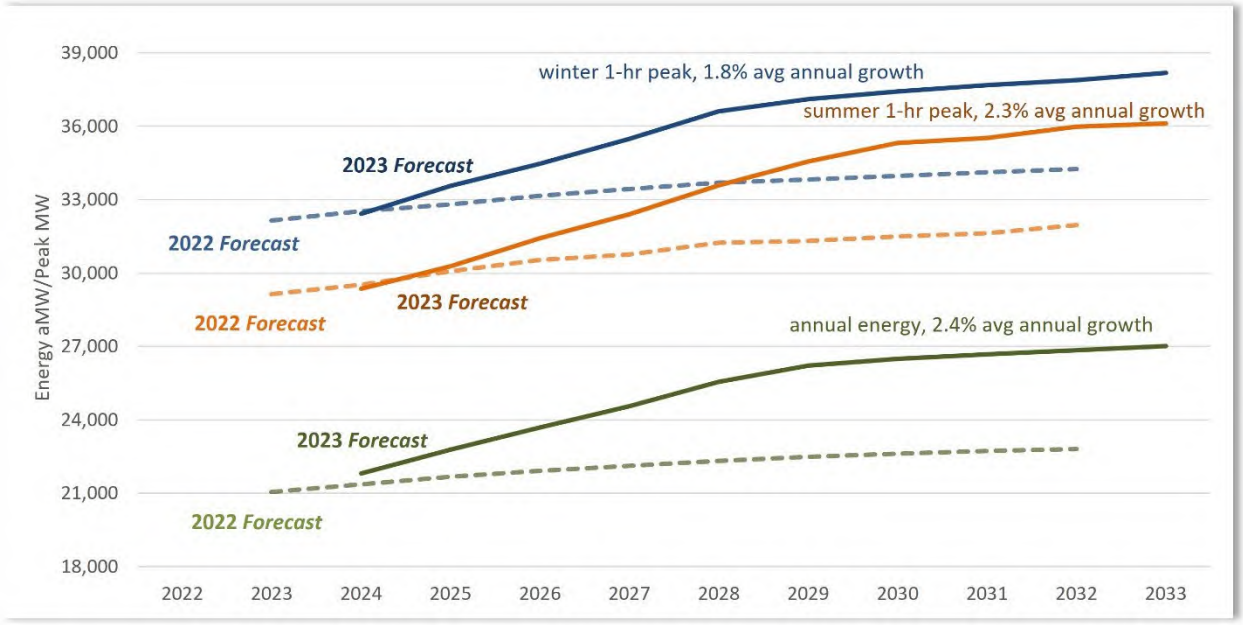
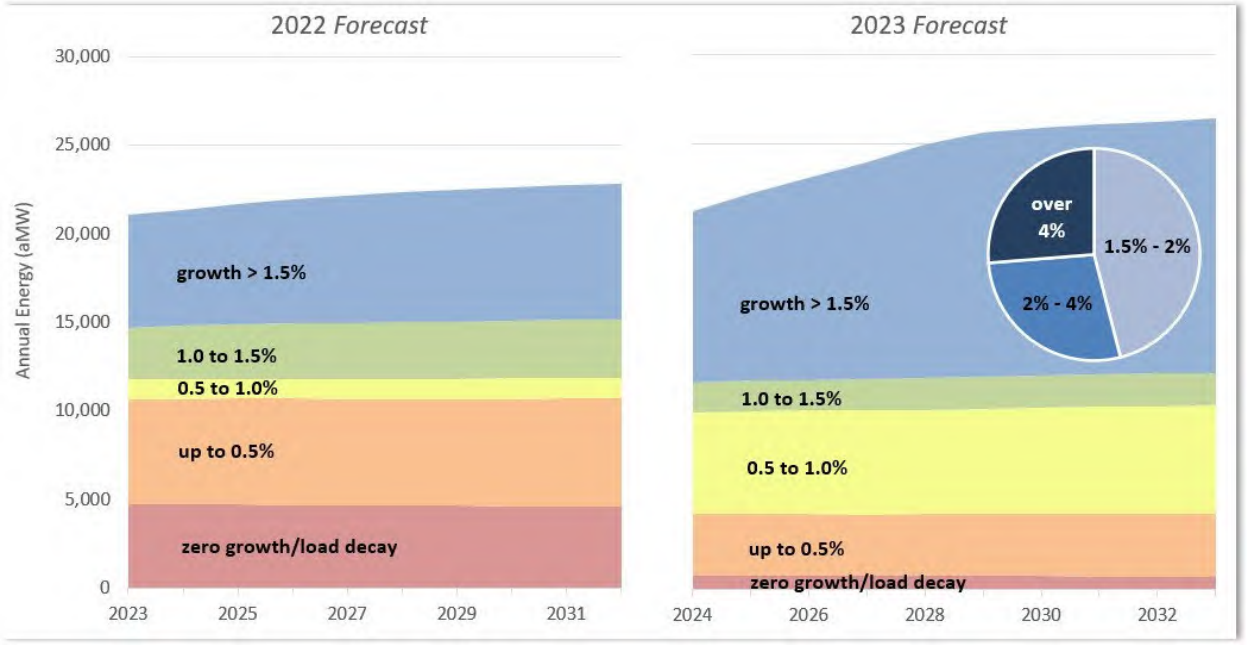


Figure 1 on page 4 shows the 2023 load forecasts in solid lines and last year's forecasts in the dashed lines. The 2023 loads reflect a markedly different trajectory than past forecasts, with a 20 percent increase in load growth in the first five years. Much of the expected growth can be attributed to new industrial customers' solidifying plans and schedules for development. The projected loads flatten out over the latter five years of the *2023 Forecast*. Annual energy, winter and summer peak forecasts increase at roughly the same magnitude in the first five years, indicating that prospective new load is flat and not necessarily seasonal.

Most utilities projecting load growth

Anticipated load growth is based on utilities' unique circumstances such as service territory characteristics, local economic factors and energy policies. This results in varying load projections, with some utilities expecting flat or little load growth and other utilities anticipating marginal to substantial increases in load growth.

Figure 2: Load Forecast Growth Rate Comparison 2022 vs. 2023



In general, utility load growth rates are shifting up, as evidenced by the comparison of the 2022 and 2023 *Forecasts* in Figure 2 above. Here individual utility annual energy loads are aggregated into ten-year load growth bins. For example, the yellow bin is the aggregate load of utilities projecting a load growth between 0.5 percent and 1 percent. In the 2022 *Forecast*, utilities with the highest projected load growth (over 1.5 percent, blue bin) represented roughly a quarter of the regional load by the last year of the forecast. In this year's *Forecast*, the share of load from utilities projecting load growth above 1.5 percent has doubled and now represents about half of the Northwest load by 2033. Within the blue bin, about a quarter represents load growth above 4 percent.

As noted earlier, the primary driver for increased growth rates is new industrial loads. While these loads are starting to show up in the utility load projections with more certainty, supply chain issues and changing economic conditions can affect the timing of these new large industrial customer loads.

Electrification and climate change effects still coming

Two elements that will impact future loads are electrification and climate change, both of which are expected to unfold and affect loads differently across the region. Machines that currently run on fossil fuels like cars and heating systems are being replaced with electric versions, but electrification is a formidable task and hard to predict, which is why the potential impact of electrification is slight in this year's *Forecast*.

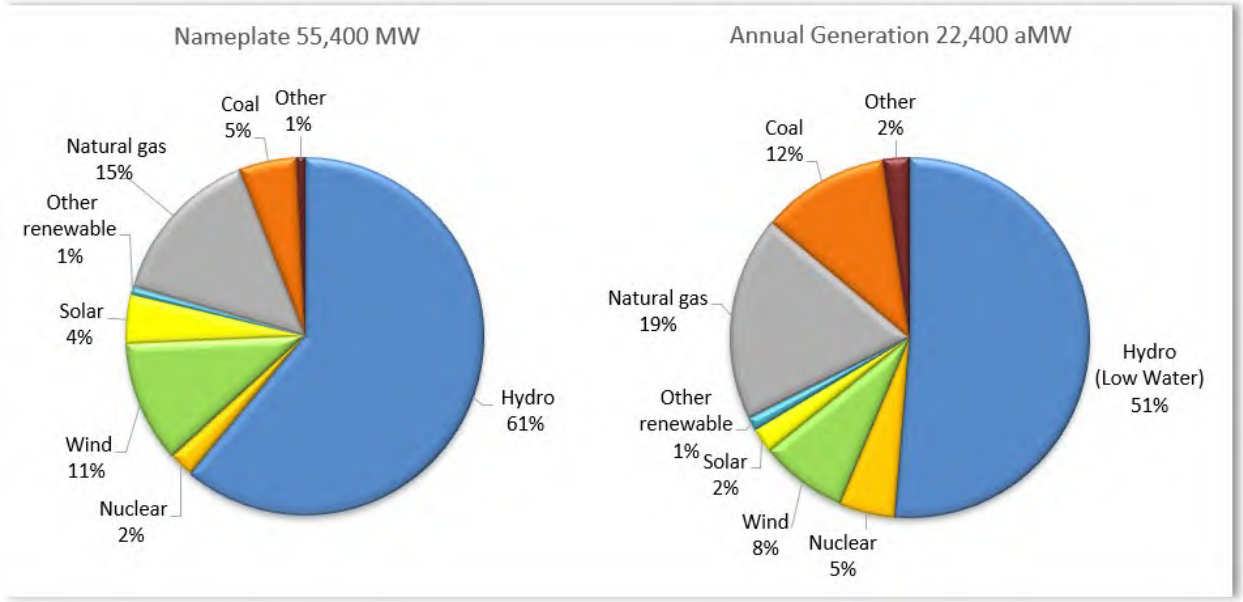
As electric vehicle adoption among consumers increases, some utilities are starting to project increases in demand. Electrification is not expected to impact utilities uniformly and other potential electrification opportunities driven by new building codes, for example, have yet to be completely understood and incorporated. The overall effect of electrification and our understanding of it is expected to increase over the next several years.

Experiences from weather can influence customer choices which impact load such as new or increased use of air conditioning. Many utilities are reporting that effects of climate change have increased their summer peak and/or decreased their winter peak. Utilities are including the effects of climate change into projected loads at different levels of granularity. Some utilities are emphasizing more recent years of weather and temperature, capturing the extreme events we are starting to see more frequently. Other utilities have incorporated global climate models into their forecasting to simulate what future climate effects on load could look like. Utilities representing about one third of the total load have not incorporated climate change into their projected loads.

Hydropower, Energy Efficiency Remain Strong Foundation

The majority of Northwest generation is carbon-free, and hydropower remains the foundation. In Figure 3 on page 7, the left pie shows Northwest utilities' generating resources nameplate capacity (similar to last year at about 55,400 MW), and the right pie is the expected annual energy from these resources. Resource fuel types move around the clock from clean to carbon emitting. Even under low water conditions, hydropower provides over half of total utility generation on an energy basis and clean energy resources make up almost 70 percent of the total annual utility generation. With increasing projected load and the push to decarbonize the power sector, wind and solar along with other clean resources will increase in share. Hydropower will continue to play an important role in reliability because of the Northwest's hydropower's storage and flexibility characteristics.

Figure 3: Northwest Utilities Generating Resources 2023



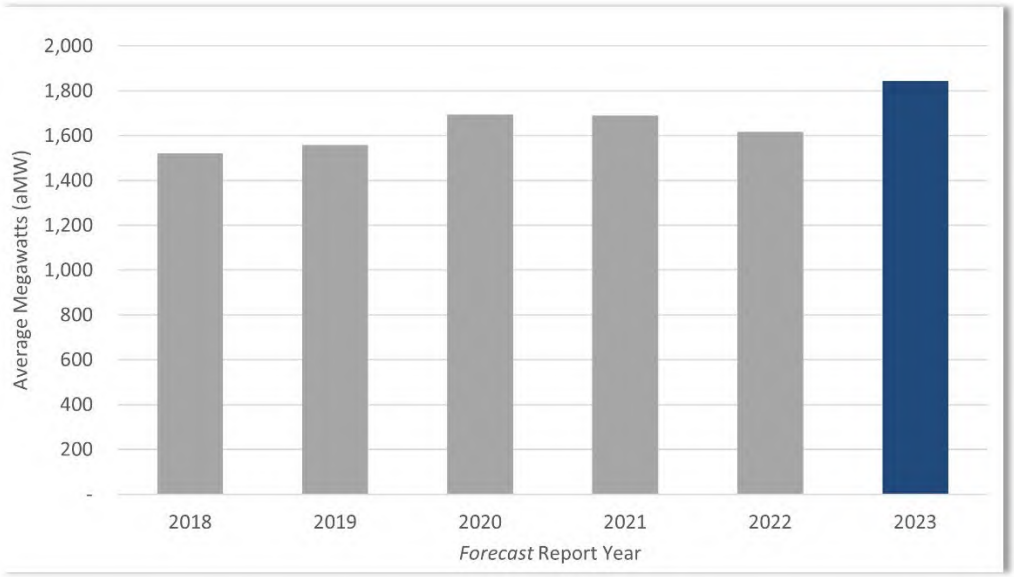
On path for decarbonizing power supply

Several utilities are steadily phasing out coal-fired generation. By 2026, these utilities will have reduced their reliance on coal by over 4,800 megawatts since 2019. As utilities keep some options on the table to meet near-term increases in demand during a period with high resource development risk, plans are shifting. Compared to last year's *Forecast*, 222 megawatts of planned coal exits were pushed back from no later than the end of 2025 to be no later than the end of 2029. Also, natural gas resources are forecast to have an increased role for reliability until energy storage and other emerging technologies are proven. Plans are progressing to convert Jim Bridger coal units 1 and 2 to natural gas in 2024. These resources provide a bridge to meet peak demand and fill in during potential low water years until sufficient new capacity resource technologies and transmission can be added. Over time as emissions and clean energy targets increase, natural gas use is projected to diminish.

Energy efficiency and demand-side innovations are mainstays

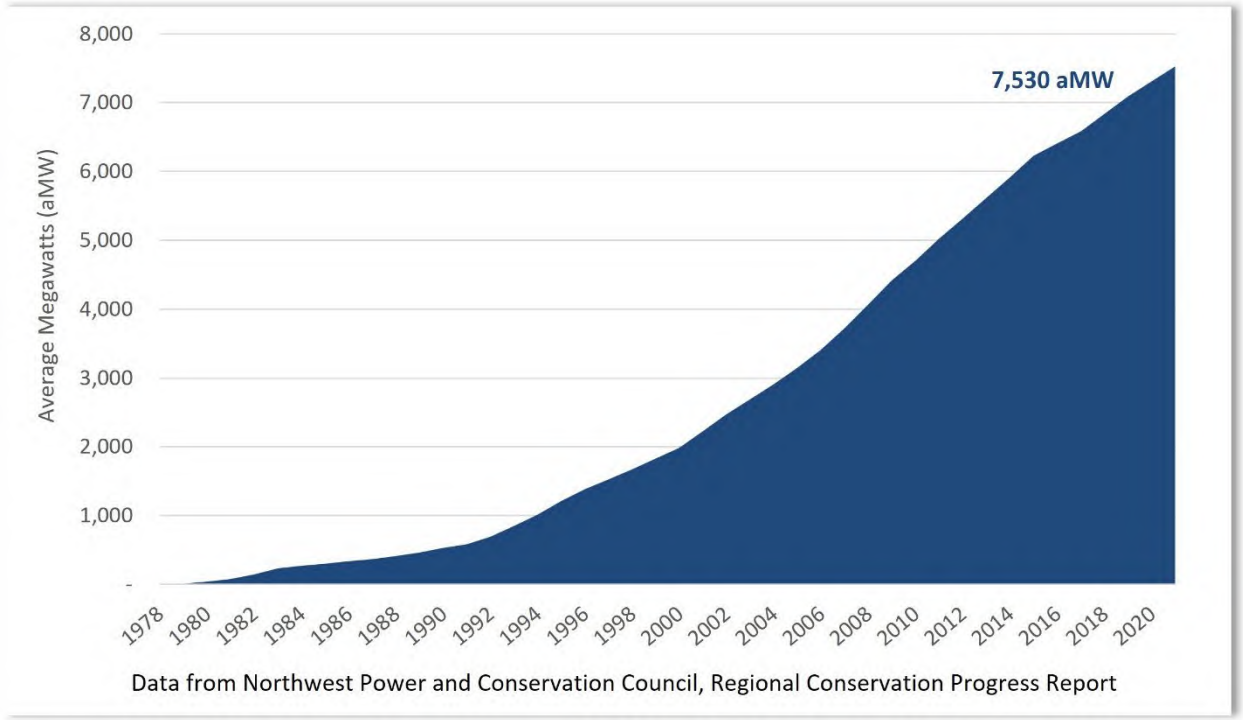
Utilities are projecting greater energy efficiency savings compared to last year's forecast, recognizing energy efficiency as a key resource in the region. Figure 4 on page 8 is a snapshot of the ten-year projected cumulative savings from the past several *Forecasts*. The ten-year savings projected in the 2023 *Forecast* are slightly higher, as utilities seek more savings to meet growing capacity and energy needs during the clean energy transition.

Figure 4: 10-year Cumulative Energy Efficiency Projections



Over the past 40 years, the region has achieved over 7,500 average megawatts of energy efficiency savings – over 60% of which are from utility programs, per the Northwest Power and Conservation Council (Figure 5). The remaining savings come from the Northwest Energy Efficiency Alliance market transformation efforts, state codes and federal standards, and other savings occurring in the market beyond direct program dollars.

Figure 5: Cumulative Regional Energy Efficiency Savings

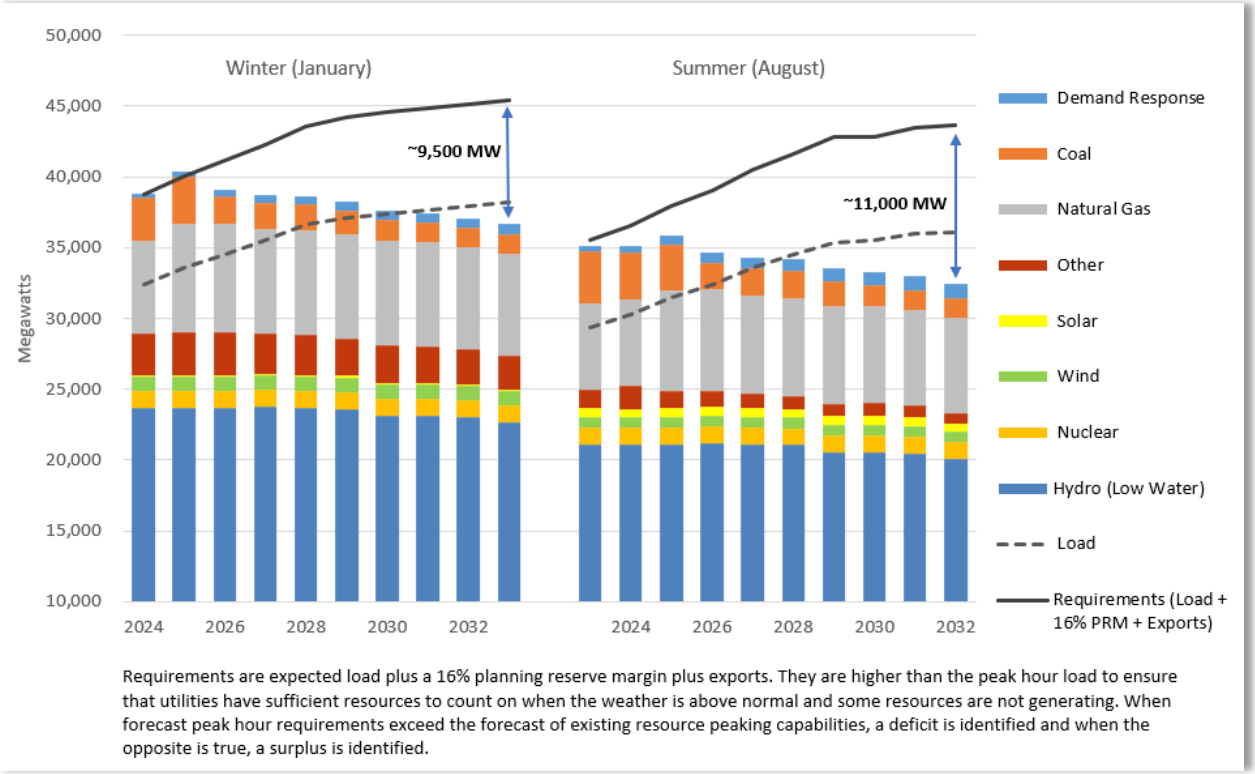


In addition to energy efficiency, utilities continue to deploy and find new ways to rely on customers to reduce energy use at peak times. The *Forecast* projects regional demand response programs will grow. For example, summer demand response is projected to reduce the region's one hour peak by about 400 megawatts in 2024 and by over 950 megawatts in 2033. On average, summer demand response programs provide about 35 percent more peak hour load reduction compared to winter programs. Regional utilities continue to seek opportunities for demand response programs that can provide mutual benefits to the customer and the grid.

Summer Peak Trend Changes

For the first time, the *Forecast* projects the region needs higher amounts of summer capacity resources to meet summer peak hour demand (electricity use) compared to the winter capacity needs. Figure 6 below shows the winter and summer peak load and resource picture if no planned future resources are procured. By the last year of the *Forecast*, the summer peak deficit grows to over 11,000 megawatts and the winter deficit gets above 9,000 megawatts. Winter peak hour demand remains higher than summer. Observed changes in resources are a bigger factor than changes in loads. Generating resources are forecast to contribute more to meet peak hour demand in winter. Summer generating resource contributions are changing less. On the load side, summer peak hour loads are increasing faster than winter peak hour loads.

Figure 6: Peak Capacity Load/Resource Picture



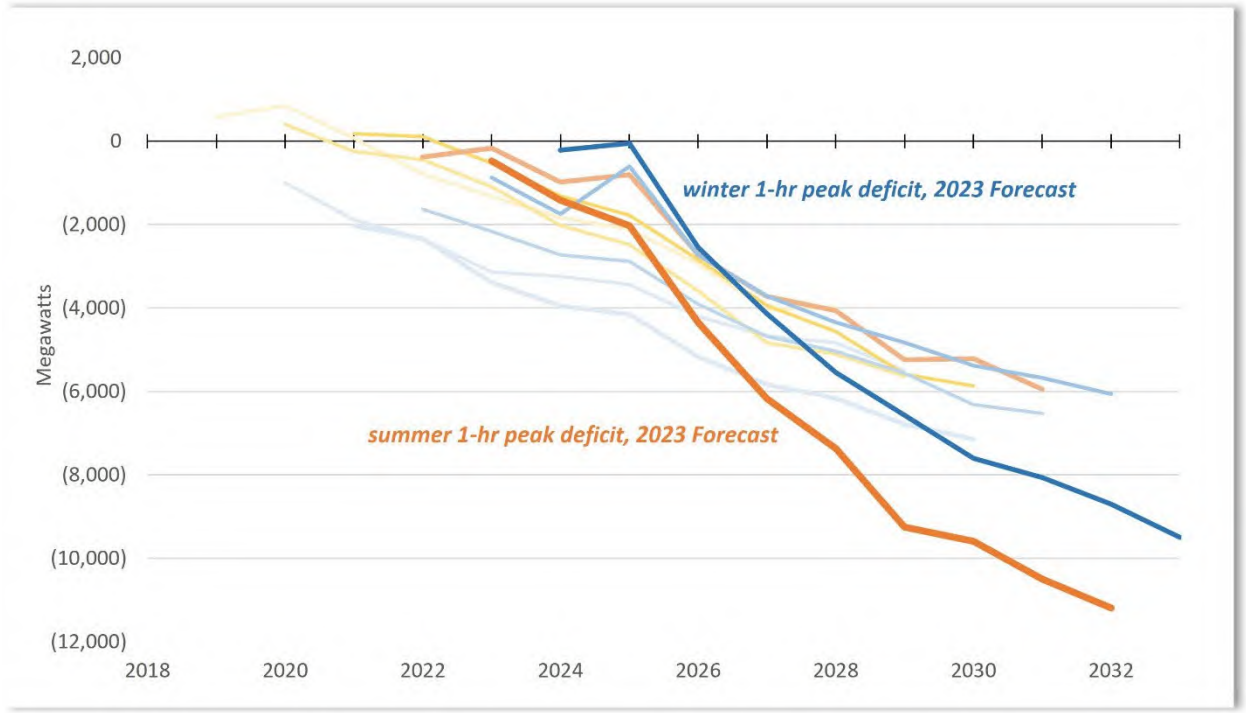
Requirements are expected load plus a 16% planning reserve margin plus exports. They are higher than the peak hour load to ensure that utilities have sufficient resources to count on when the weather is above normal and some resources are not generating. When forecast peak hour requirements exceed the forecast of existing resource peaking capabilities, a deficit is identified and when the opposite is true, a surplus is identified.

The *Forecast* provides a comparison of Northwest utilities' peak hour requirements to the anticipated resource peaking capabilities. A deficit is not a bright line for how much generation needs to be added to keep the lights on. Rather, the *Forecast's* value is the observation of trends over time and brings another element of situational awareness for the region's utilities to identify areas for additional coordination. The figure also shows the region's move away from coal and expectation that natural gas resources play a steady role in serving peak in the region. Utilities are announcing coal plant retirements and exits as they continue to explore the options for their replacements.

Figure 7 below compares the summer and winter 1-hour peak surplus or deficit across *Forecasts* from 2019 to 2023. The solid bold line is this year's projection. The dashed bold line is the 2022 *Forecast's* projections. In the next five years, the summer peak deficit and need for power is anticipated to grow to about 8,000 megawatts and winter approaches 6,000 megawatts.

This view does not include planned future resources. It is also based on a fixed set of assumptions including normal weather loads, a 16 percent planning reserve margin, low hydro generation, the expected 1-hour peaking capability for generating resources and zero short-term market purchases. The region is monitoring the higher summer peak deficit and the growing magnitude of the deficit. The observed summer deficit can reverse back to higher winter deficits if insufficient winter supply is added and if electrification increases winter peak loads.

Figure 7: Peak Capacity Surplus/Deficit *2019 - 2023 Forecasts*

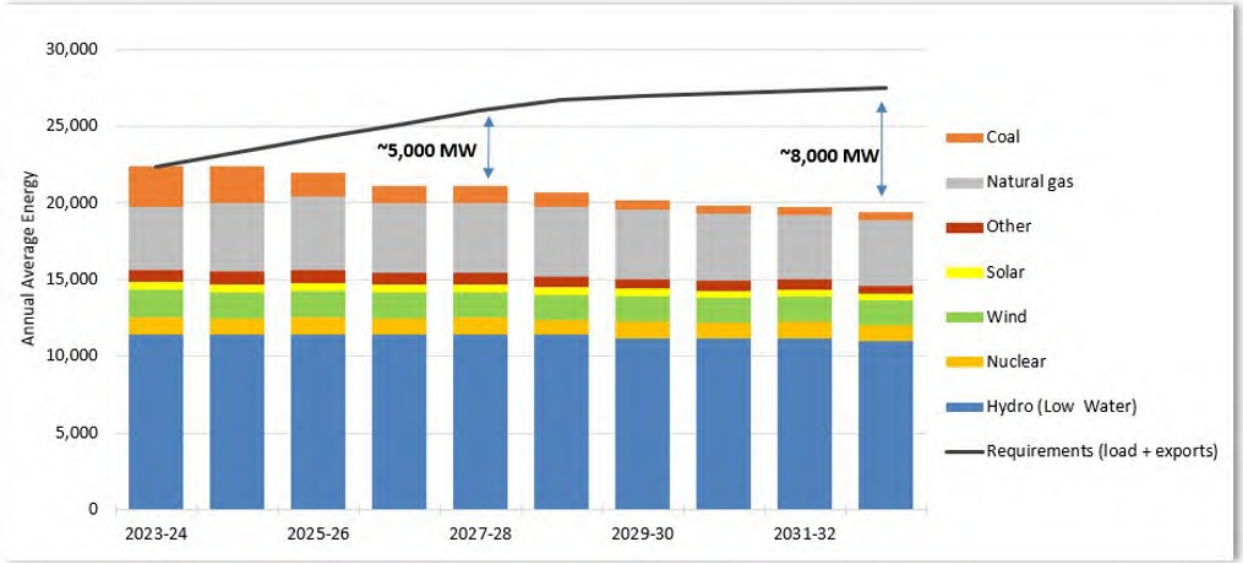


Energy picture helps gage reliability

Monitoring energy deficits can help determine the balance between energy and capacity resources needed in the region. Non-utility owned generation in the region, available power surpluses in interconnected regions, better than low hydro generation and transmission upgrades and expansion can help fill the gaps. Utilities are attentive to these factors as they determine what new resources can best complement their existing power supply.

In addition to summer and winter peak needs, the *Forecast* monitors annual energy needs (electricity demand across all hours of the year). This year's *Forecast*, like last year, shows a growing annual energy deficit (Figure 8) if planned future resources are not acquired. Compared to last year's *Forecast,* where an almost 4,000 average megawatts need was predicted by year ten, this *Forecast's* energy deficit reaches over 8,000 average megawatts in ten years. Watching changes in these trends provides the region with greater situational awareness and identifies areas where more coordination can help.

Figure 8. Annual Energy Picture



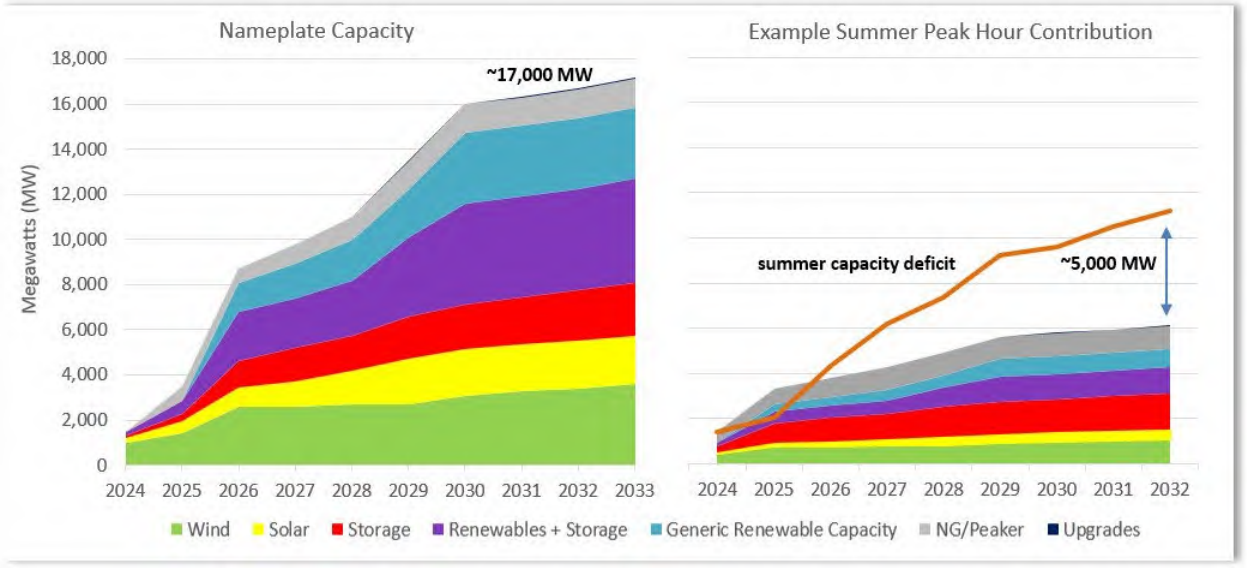
Renewables Combined with Energy Storage Dominate Utility Plans

Utilities are planning for new wind, solar and battery projects to provide much of the new generation to meet rising electric demand and emission reduction goals at a pace that exceeds previous levels. For meeting needs in the next five years, utilities increased the nameplate capacity additions in their preferred portfolios compared to last year's *Forecast*. This translates to over 11,000 megawatts of additions in the next five years, which is up by almost 3,000 megawatts compared to last year's *Forecast*. This *Forecast* anticipates new resource build commitments to start to line up and announcements to roll out before the next *Forecast*. In addition, some utility customers may be procuring their own resources and this *Forecast* may not reflect those additions.

Figure 9 below shows what resources Northwest utilities plan to add to meet their needs. In addition to the increasing amount of renewable energy co-located with storage resources and standalone storage, utilities are looking at capacity resources that include natural gas, peaker and "generic" capacity resources. Some utilities have identified an intention to run the peakers using alternative fuels such as biodiesel or hydrogen.

Figure 9 also shows how these resources might contribute on a regional planning basis to the summer picture highlighted in Figures 6 and 7. The Nameplate capacity (in megawatts), is a measure of the maximum output of a given electric generation plant under optimal conditions, like strong winds or full sun. Generation, measured in megawatt hours, is how much electricity is actually produced. Given the generic nature of the utilities' preferred resource portfolios, this illustration can vary considerably based on assumptions made about the resources' geographic location, type, storage capacity amongst other factors. Using the assumptions made in preparing Figure 9 (Example Summer Peak Hour Contribution), the summer capacity deficit shrinks with planned future resources. However, it also shows the region may require additional resources to fill the gap. Peak contributions will also vary depending on the time of year.

Figure 9: Planned Future Resources Picture



Landmark clean energy legislation and unprecedented federal government funding can help advance clean energy technology and modernize the grid. Emerging technologies including advanced nuclear, offshore wind, renewable hydrogen and long-duration storage are being championed as part of the grid of the future. While these technologies are being explored, they do not show up in the information reported in this year's *Forecast*. In the coming decade, technological advancements will continue to help utilities diversify the mix of clean generation, and utilities will continue to adapt their plans as more information about future loads and resources and transmission opportunities are known.

Transmission solutions and regional coordination crucial to keeping a reliable grid

Several utilities also identify new transmission projects in their preferred resource portfolios and are working to enhance the transmission system. This has been outside the scope of the *Forecast* data tracking. However, transmission is a critical component to delivering generation, much of it from renewable resources, to load centers. New transmission can also make more efficient use of existing resources, possibly reducing the new resource additions required.

Utilities are also enhancing regional coordination by working together to address adequacy concerns and develop enhanced market solutions. The Western Resource Adequacy Program approved by the Federal Energy Regulatory Commission in February 2023 has been recognized as a first-of-a-kind program for resource adequacy that will operate with participants across a wide geographic footprint. Tools like the Western Energy Imbalance Market give system operators real-time visibility across the interconnected grid, which helps share load and resource diversity more efficiently. Expanding coordinated wholesale energy markets can help make more efficient use of existing and newly added resources.

Overview

Each year the *Northwest Regional Forecast* compiles utilities' 10-year projections of electric loads and resources which provide information about the region's need to acquire new power supply. The *Forecast* is a comprehensive look at the capability of existing and new electric generation, long-term firm contracts, expected savings from demand side management programs, and other components of electric supply and demand in the Northwest.

This report presents estimates of annual average energy, seasonal energy and winter and summer peak capability in Tables 1 through 4 of the Northwest Region Requirements and Resources section. These metrics provide a multidimensional look at the Northwest's need for power and underscore the growing complexity of the power system. The information is intended to identify regional trends and general themes based on utilities' integrated resource planning results, rather than provide a precise metric of resource adequacy.

Northwest new and existing generating resources are shown by fuel type. Existing and committed resources are listed in Tables 5, 6, 10 and 11. Table 5, Recently Acquired Resources, highlights projects and supply that became available most recently. Table 6, Committed New Supply, lists projects where construction has started or supply is firmly committed, as well as contractual arrangements that have been made for providing power at a future time. Table 10, Northwest Utility Generating Resources, is a comprehensive list of generating resources that make up the electric power supply for the Pacific Northwest that are utility-owned or utility-contracted. Table 11, Independent Owned Generating Resources, lists generating projects owned by independent power producers and located in the Northwest.

In addition, utilities have demand side management programs in place to reduce the need for generating resources. Table 7, Demand-Side Management Programs, provides a snapshot of expected savings from these programs for the next ten years. Lastly, Table 8, Planned Resources, is a compilation of what utilities have reported in their individual integrated resource plans to meet future need.

Planning Area

The Northwest Regional Planning Area is the area defined by the *Pacific Northwest Electric Power Planning and Conservation Act*. It includes: the states of Oregon, Washington, and Idaho; Montana west of the Continental Divide; portions of Nevada, Utah, and Wyoming that lie within the Columbia River drainage basin; and any rural electric cooperative customer not in the geographic area described above but served by BPA on the effective date of the *Act*.

Northwest Region Requirements and Resources

Table 1. Northwest Region Requirements and Resources – Annual Energy shows the sum of the individual utilities' requirements and firm resources for each of the next 10 years. Expected firm load and exports make up the total firm regional requirements.

Average Megawatts	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33
Firm Requirements										
Load [1/]	21,814	22,791	23,694	24,558	25,545	26,225	26,485	26,681	26,841	27,006
Exports	520	502	502	501	501	501	501	501	501	501
Total	22,334	23,293	24,195	25,060	26,046	26,726	26,986	27,182	27,342	27,507
Firm Resources										
Hydro [2/]	11,459	11,439	11,424	11,462	11,424	11,402	11,200	11,200	11,161	11,005
Small Thermal/Misc.	28	28	28	28	28	18	11	11	11	11
Natural Gas [3/]	4,107	4,497	4,801	4,551	4,546	4,544	4,474	4,426	4,225	4,222
Renewables-Other	276	275	273	274	269	268	268	266	264	260
Solar	503	503	503	502	502	501	501	500	498	483
Wind	1,757	1,747	1,747	1,721	1,661	1,623	1,611	1,596	1,596	1,622
Cogeneration	41	41	34	32	31	31	31	31	31	31
Imports	488	488	467	467	453	380	324	310	310	222
Nuclear	1,116	994	1,116	994	1,116	994	1,116	994	1,116	994
Coal	2,583	2,356	1,593	1,065	1,068	891	593	479	497	508
Total	22,357	22,366	21,985	21,096	21,097	20,652	20,127	19,810	19,708	19,357
Surplus (Deficit)	**22**	**(927)**	**(2,210)**	**(3,963)**	**(4,949)**	**(6,074)**	**(6,859)**	**(7,372)**	**(7,634)**	**(8,150)**

[1/] Load net of energy efficiency
[2/] Firm hydro for energy is the generation expected assuming critical (8%) water condition (the methodology is changed for the 2023 report)
[3/] More energy may be available from natural gas power plants

Table 2. Northwest Region Requirements and Resources – Monthly Energy shows the monthly energy values for the 2023-2024 operating year.

Average Megawatts	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul
Firm Requirements												
Load [1/]	21,304	19,497	19,744	21,984	24,383	24,475	23,492	21,768	20,586	20,069	21,042	22,349
Exports	685	660	501	495	495	455	455	455	455	455	533	597
Total	21,989	20,157	20,245	22,479	24,878	24,930	23,947	22,223	21,041	20,524	21,576	22,946
Firm Resources												
Hydro [2/]	11,335	9,198	9,927	12,737	12,077	12,509	10,513	10,859	10,382	10,057	14,644	13,042
Small Thermal/Misc.	26	26	27	29	31	30	30	30	30	29	22	25
Natural Gas	4,198	3,998	3,784	4,138	4,434	4,436	4,163	4,065	3,658	3,521	4,140	4,190
Renewables-Other	270	275	282	287	284	280	281	283	267	260	267	272
Solar	707	588	403	210	156	174	314	464	611	707	790	832
Wind	1,635	1,466	1,696	1,880	1,801	1,709	1,776	1,870	1,956	1,780	1,902	1,689
Cogeneration	32	40	37	43	45	45	46	43	42	41	40	35
Imports	508	504	560	765	853	553	558	475	378	367	377	379
Nuclear	1,116	1,116	1,116	1,116	1,116	1,116	1,116	1,116	1,116	1,116	1,116	1,116
Coal	3,247	3,090	2,617	2,802	2,611	2,408	2,387	2,466	1,962	2,236	2,426	2,739
Total	23,075	20,299	20,449	24,007	23,406	23,261	21,184	21,672	20,401	20,113	25,724	24,317
Surplus (Deficit)	**1,086**	**142**	**204**	**1,528**	**(1,472)**	**(1,669)**	**(2,763)**	**(551)**	**(640)**	**(411)**	**4,149**	**1,372**

[1/] Load net of energy efficiency

[2/] Firm hydro for monthly energy is the generation expected assuming critical (8%) water condition (the methodology is changed for the 2023 report)

Table 3. Northwest Region Requirements and Resources – Winter Peak

The sum of the individual utilities' firm requirements and resources for the peak hour in January for each of the next 10 years are shown in this table. Firm peak requirements include a planning margin to account for planning uncertainties.

Megawatts	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Firm Requirements										
Load[1/]	32,424	33,557	34,471	35,485	36,601	37,111	37,417	37,673	37,886	38,180
Exports	1,143	1,143	1,142	1,142	1,142	1,142	1,142	1,142	1,142	1,142
Planning Margin[2/]	5,188	5,369	5,515	5,678	5,856	5,938	5,987	6,028	6,062	6,109
Total	38,755	40,069	41,128	42,304	43,599	44,190	44,546	44,842	45,089	45,430
Firm Resources										
Hydro[3/]	23,670	23,669	23,669	23,761	23,662	23,618	23,136	23,136	23,043	22,672
Demand Response	295	385	455	539	613	620	654	679	696	720
Small Thermal/Misc.	193	193	195	193	194	175	176	177	178	180
Natural Gas	6,566	7,629	7,630	7,370	7,370	7,370	7,370	7,370	7,137	7,137
Renewables-Other	327	327	327	319	319	319	319	315	311	311
Solar	99	100	100	100	100	100	100	100	99	99
Wind	1,062	1,079	1,067	1,046	1,044	1,054	1,062	1,060	1,041	1,051
Cogeneration	38	38	38	36	36	36	36	36	36	36
Imports	2,072	2,108	2,027	1,738	1,715	1,498	1,495	1,314	1,272	1,145
Nuclear	1,169	1,169	1,169	1,169	1,169	1,169	1,169	1,169	1,169	1,169
Coal	3,056	3,327	1,905	1,902	1,832	1,661	1,430	1,428	1,410	1,410
Total	38,547	40,024	38,582	38,172	38,053	37,621	36,947	36,784	36,393	35,931
Surplus (Deficit)	**(208)**	**(45)**	**(2,546)**	**(4,132)**	**(5,546)**	**(6,569)**	**(7,599)**	**(8,059)**	**(8,696)**	**(9,499)**

[1/] Expected (1-in-2) load net of energy efficiency

[2/] Planning margin is 16% of load (this assumption was updated and set with the *2018 Northwest Regional Forecast*)

[3/] Firm hydro for capacity is the generation expected assuming critical peaking capability as determined by the utility sponsor.

Table 4. Northwest Region Requirements and Resources – Summer Peak

The sum of the individual utilities' firm requirements and resources for a peak hour in August for each of the next 10 years are shown in this table. Firm peak requirements include a planning margin to account for planning uncertainties.

Megawatts	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Firm Requirements										
Load [1/]	29,362	30,272	31,429	32,396	33,577	34,557	35,311	35,514	35,987	36,121
Exports	1,443	1,443	1,443	1,442	1,539	1,516	1,812	1,657	1,706	1,706
Planning Margin [2/]	4,698	4,844	5,029	5,183	5,372	5,529	5,650	5,682	5,758	5,779
Total	35,502	36,558	37,900	39,021	40,488	41,602	42,773	42,853	43,450	43,606
Firm Resources										
Hydro [3/]	21,101	21,101	21,101	21,193	21,101	21,057	20,574	20,574	20,482	20,111
Demand Response	385	516	629	717	807	882	879	910	936	954
Small Thermal/Misc.	192	192	194	191	192	192	183	184	185	187
Natural Gas	6,036	6,091	7,154	7,150	6,912	6,912	6,912	6,912	6,693	6,693
Renewables-Other	330	329	329	321	321	321	321	321	317	312
Solar	583	566	605	602	601	602	600	598	592	587
Wind	792	756	793	788	780	764	764	771	765	736
Cogeneration	41	41	41	32	30	30	30	30	30	30
Imports	792	1,065	616	606	499	399	359	359	359	209
Nuclear	1,163	1,163	1,163	1,163	1,163	1,163	1,163	1,163	1,163	1,163
Coal	3,687	3,323	3,244	1,910	1,907	1,903	1,737	1,431	1,431	1,431
Total	35,101	35,142	35,868	34,673	34,313	34,226	33,522	33,254	32,951	32,412
Surplus (Deficit)	**(401)**	**(1,416)**	**(2,032)**	**(4,348)**	**(6,175)**	**(7,376)**	**(9,251)**	**(9,599)**	**(10,500)**	**(11,194)**

[1/] Expected (1-in-2) load net of energy efficiency

[2/] Planning margin is 16% of load (this assumption was updated and set with the *2018 Northwest Regional Forecast*)

[3/] Firm hydro for capacity is the generation expected assuming critical peaking capability as determined by the utility sponsor

Northwest New and Existing Resources

Table 5. Recently Acquired Resources highlights projects that have recently become available.

Project	Fuel/Tech	Nameplate (MW)	Winter Peak (MW)	Summer Peak (MW)	Annual Energy (aMW)	Utility/Owner
Box Canyon	Hydro	90	90			Clark PUD
Contract	Hydro	40	25	40	28	Franklin PUD
Short-Term Winter Capacity Product	Contract	25	25			Snohomish PUD
Firm Winter Energy Product	Hydro	25	25			Snohomish PUD
Columbia Basin Hydro projects	Hydro	146				Avista
Mid C Extension-Rock Island & Rocky Reach 2	Hydro	87.5				Avista
Mid C Extension-Rock Island & Rocky Reach 3	Hydro	87.5				Avista
Durkee Solar	Solar	3				Idaho Power
Jackpot Holdings, LLC	Solar	120				Idaho Power
MTSUN	Solar	80				NorthWestern Energy
Solarize Rogue Comm. Solar	Solar	0.1				PacifiCorp
Wallowa County Community Solar, LLC	Solar	0.4				PacifiCorp
Wheatridge Renewable Energy Facility	Solar	50				Portland General Elec.
Wheatridge Renewable Energy Facility	Battery	30				Portland General Elec.
Lund Hill Solar	Solar	150				Puget Sound Energy
Total (Nameplate)		**935**				

Table 6. Committed Resources details firm contracts and generating projects that are committed to come online. All supply listed in this table is included in the regional analysis of power needs.

Project	Year	Fuel/Tech	Nameplate (MW)	Utility/Owner
Moore's Hollow	2023	Solar	42	Idaho Power
Prairie City	2023	Solar	29	Idaho Power
Apex Solar	2023	Solar	80	NorthWestern Energy
Black Eagle Upgrade	2023	Hydro	2	NorthWestern Energy
Holter Upgrade	2023	Hydro	1	NorthWestern Energy
Yellowstone Co. Generating Station	est. 2024	Nat.Gas	175	NorthWestern Energy
Sunnyside Solar, LLC	2023	Solar	5	PacifiCorp
Clearwater Wind	2023	Wind	311	Portland General Electric
Daybreak Solar	2023	Solar	138	Portland General Electric
Wasco County Solar	2023	Solar	60	Portland General Electric
Li-Ion Battery Energy Storage	2025	Battery	25	Snohomish County PUD
Total (Nameplate)			**868**	

Table 7. Demand-Side Management Programs is a snapshot of the regional utilities' efforts to manage demand. The majority of the energy efficiency savings are from utility programs and included in the regional analysis of power needs. This table also shows cumulative existing plus new demand response programs reported by utilities.

	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33
Energy Efficiency (aMW)										
Incremental	176	203	180	186	186	183	193	185	178	172
Cumulative	176	379	559	745	931	1,115	1,308	1,492	1,670	1,842
Demand Response (MW) existing + forecast[1]										
Winter	198	198	272	363	444	508	539	567	595	619
Summer	401	401	504	599	688	764	819	846	876	903

[1] Values are program effectiveness, nameplate values are higher.

Table 8. Planned Future Resources catalogues future resources that utilities have identified to meet their own needs. These resources are subject to change and are not included in the regional analysis of power needs.

Project	Year	Fuel/Tech	Nameplate (MW)	Utility
Kettle Falls Modernization	2027	Biomass	12	Avista
Montana Wind	2025, 2028	Wind	200	Avista
Reciprocating ICE	2031	Natural Gas	55	Avista
Combustion Turbine – ID	2027	Natural Gas	84	Avista
Combustion Turbine – WA	2027	Natural Gas	84	Avista
Post Falls Hydro Modernization	2026	Hydro	8	Avista
River Road Cap. Increase	2024	Natural Gas	-	Clark Public Utilities
Palouse Junction	2025	Solar PV	10	Franklin PUD
Natural Gas	2024	Natural Gas	357	Idaho Power
Solar PV	2025 - 2029	Solar PV	985	Idaho Power
Storage	2023 – 2032	Storage	705	Idaho Power
Wind	2024	Wind	700	Idaho Power
Broadview	TBD	Solar + Battery	160	NorthWestern Energy
Caithness Beaver Creek II	TBD	Wind + Battery	60	NorthWestern Energy
Caithness Beaver Creek III	TBD	Wind + Battery	60	NorthWestern Energy
Cochrane Upgrade	2024	Hydro	2	NorthWestern Energy
ConEd Pondera	TBD	Wind	20	NorthWestern Energy
ConEd Teton	TBD	Wind	19	NorthWestern Energy
ConEd Wheatland	TBD	Wind	75	NorthWestern Energy
Hauser Upgrade	2025	Hydro	1	NorthWestern Energy
Jawbone	TBD	Wind	80	NorthWestern Energy
Meadowlark	TBD	Solar + Battery	20	NorthWestern Energy
Thompson Falls Upgrade	2031	Hydro	4	NorthWestern Energy
Trident	TBD	Solar + Battery	160	NorthWestern Energy
Battery	2026	Battery	200	PacifiCorp
Solar + Storage	2025 - 2030	Solar + Storage	2,861	PacifiCorp
Wind	2026 - 2030	Wind	767	PacifiCorp
Wind + Storage	2029	Wind + Storage	160	PacifiCorp
Generic Capacity Resource	2026	Capacity	1326	Portland General Electric
Generic Capacity Resource	2027	Capacity	201	Portland General Electric
Generic Capacity Resource	2028	Capacity	254	Portland General Electric
Generic Capacity Resource	2029	Capacity	351	Portland General Electric
Generic Capacity Resource	2030	Capacity	1005	Portland General Electric
DER Solar Ground	2025	Solar PV	10	Puget Sound Energy
DER Solar Rooftop	2025 – 2033	Solar PV	260	Puget Sound Energy
DER Storage	2026 – 2031	Storage	150	Puget Sound Energy
Frame Peaker Biodiesel	2024, 2026, 2028	Biodiesel	711	Puget Sound Energy
Li-ion 4hr Battery	2025 – 2032	Battery	700	Puget Sound Energy
Li-ion 6hr Battery	2033	Battery	100	Puget Sound Energy
MT Pumped Hydro	2026	Storage	200	Puget Sound Energy
MT Wind East	2026	Wind	400	Puget Sound Energy

Project	Year	Fuel/Tech	Nameplate (MW)	Utility
Solar + Battery	2024, 2029	Solar PV + Battery	450	Puget Sound Energy
WA East Solar	2024 – 2029	Solar PV	700	Puget Sound Energy
Wind	2024 – 2030	Wind	1000	Puget Sound Energy
WA Pumped Hydro	2026	Storage	200	Puget Sound Energy
Wind + Battery	2025 - 2029	Wind + Battery	750	Puget Sound Energy
Wind + Solar + Battery	2026	Wind + Solar PV + Battery	250	Puget Sound Energy
WY East Wind	2031-2033	Wind	400	Puget Sound Energy
E WA Solar	2026 - 2032	Solar PV	-	Seattle City Light
Montana Wind	2032-2033	Wind	50	Seattle City Light
E WA Solar – Large Customers	2024	Solar PV	100	Seattle City Light
Gorge Wind	2026	Wind	225	Seattle City Light
SE Oregon Solar	2026	Solar PV	75	Seattle City Light
Li-ion Battery Storage	2025	Battery	25	Snohomish PUD
Local Utility-scale Solar	2029	Solar PV	5	Snohomish PUD
Long-duration Energy Storage	2030	Storage	50	Snohomish PUD
Short-term Winter Capacity Market Product	2024	Market	25	Snohomish PUD
Total (Nameplate)			**17,822**	

Table 9. Planned Future Resources Timeline displays the cumulative supply-side resource additions over time, combining the nameplate MW values of resources from Table 8 (NW utility owned/contracted only, IPP additions not included).

Nameplate MW	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Wind	1000	1,400	2,572	2,572	2,672	2,792	3,292	3,492	3,617	3,807
Solar	200	540	860	1,140	1,490	2,025	2,055	2,085	2,115	2,145
Storage	120	350	1,175	1,505	1,585	1,865	1,995	2,075	2,230	2,330
Renewables w. Storage	150	562	2,162	2,162	2,437	3,517	4,471	4,471	4,471	4,624
Natural Gas/Peaker	619	619	856	1,024	1,261	1,261	1,236	1,291	1,291	1,291
Generic Renewable Capacity	-	-	1,326	1,527	1,781	2,132	3,137	3,137	3,137	3,137
Upgrades	12	13	21	33	33	33	33	37	37	37
TOTAL	2,101	3,484	8,972	9,963	11,259	13,625	16,219	16,588	16,898	17,371
Total renewables	1,350	2,502	6,920	7,401	8,380	10,466	12,955	13,185	13,340	13,713

Table 10. Northwest Utility Generating Resources is a comprehensive list of utility-owned and utility contracted generating resources that make up those utilities electric power supply. This table includes recently acquired and committed resources – some of the resources listed may not currently be operating. Potential resources are not included in the table.

Project	Owner	NW Utility	Nameplate (MW)
HYDRO			**33,824**
Albeni Falls	US Corps of Engineers	Federal System (BPA)	43
Alder	Tacoma Power	Tacoma Power	50
American Falls	Idaho Power	Idaho Power	92
Anderson Ranch	US Bureau of Reclamation	Federal System (BPA)	40
Arena Drop	PURPA	Idaho Power	0.5
Arrowrock Dam	Clatskanie PUD/Irr Dist	Clatskanie PUD	18
B. Smith	PacifiCorp	PacifiCorp	0.03
Baker City Hydro	PURPA	Idaho Power	0.24
Barber Dam	PURPA	Idaho Power	4
Bell Mountain	PacifiCorp	PacifiCorp	1
Big Sheep Creek	Everand Jensen	Avista Corp.	0.1
Big Cliff	US Corps of Engineers	Federal System (BPA)	18
Birch Creek	PURPA	Idaho Power	0.1
Birch Creek	PacifiCorp	PacifiCorp	3
Black Canyon # 3	PURPA	Idaho Power	0.1
Black Canyon	US Bureau of Reclamation	Federal System (BPA)	10
Black Canyon Bliss Dam	PURPA	Idaho Power	0.1
Black Creek Hydro	Black Creek Hydro, Inc.	Puget Sound Energy	4
Black Eagle	NorthWestern Energy	NorthWestern Energy	23
Blind Canyon	PURPA	Idaho Power	2
Bliss	Idaho Power	Idaho Power	75
Boise River Diversion	US Bureau of Reclamation	Federal System (BPA)	2
Bonneville	US Corps of Engineers	Federal System (BPA)	1,102
Box Canyon-Idaho	PURPA	Idaho Power	0.4
Boundary	Seattle City Light	Seattle City Light	1,119
Box Canyon	Pend Oreille County PUD	Pend Oreille County PUD	70
Briggs Creek	PURPA	Idaho Power	1
Broadwater Dam	Dept. of Natural Res. & Cons.	NorthWestern Energy	10
Brownlee	Idaho Power	Idaho Power	585
Bypass	PURPA	Idaho Power	10
Cabinet Gorge	Avista Corp.	Avista Corp.	265
Calligan Creek	Snohomish County PUD	Snohomish County PUD	6
Calispel Creek	Pend Oreille County PUD	Pend Oreille County PUD	1
Canyon Springs	PURPA	Idaho Power	0.1
Carmen-Smith	Eugene Water & Electric Board	Eugene Water & Electric Board	105
Cascade	US Bureau of Reclamation	Idaho Power	12
CDM Hydro	PacifiCorp	PacifiCorp	6
Cedar Draw Creek	PURPA	Idaho Power	2

Project	Owner	NW Utility	Nameplate (MW)
Cedar Falls, Newhalem	Seattle City Light	Seattle City Light	33
Central Oregon Siphon		PacifiCorp	5
Chandler	US Bureau of Reclamation	Federal System (BPA)	12
Chelan	Chelan County PUD	Chelan County PUD	59
Chief Joseph	US Corps of Engineers	Federal System (BPA)	2,457
C. J. Strike	Idaho Power	Idaho Power	83
Clear Lake	Idaho Power	Idaho Power	3
Clear Springs Trout	PURPA	Idaho Power	1
Clearwater #1	PacifiCorp	PacifiCorp	15
Clearwater #2	PacifiCorp	PacifiCorp	26
Cline Falls	COID	PacifiCorp	1
Cochrane	NorthWestern Energy	NorthWestern Energy	60
COID	PacifiCorp	PacifiCorp	7
Copco #1	PacifiCorp	PacifiCorp	20
Copco #2	PacifiCorp	PacifiCorp	27
Cougar	US Corps of Engineers	Federal System (BPA)	25
Cowlitz Falls	Lewis County PUD	Federal System (BPA)	70
Crystal Springs	PURPA	Idaho Power	2
Curry Cattle Company	PURPA	Idaho Power	0.2
Curtis Livestock	PacifiCorp	PacifiCorp	0.1
Cushman 1	Tacoma Power	Tacoma Power	43
Cushman 2	Tacoma Power	Tacoma Power	81
Deep Creek	Gordon Foster	Avista Corp.	0.5
Derr Creek	Jim White	Avista Corp.	0.3
Detroit	US Corps of Engineers	Federal System (BPA)	100
Dexter	US Corps of Engineers	Federal System (BPA)	15
Diablo Canyon	Seattle City Light	Seattle City Light	182
Dietrich Drop	PURPA	Idaho Power	5
Dry Creek		PacifiCorp	4
Dworshak	US Corps of Engineers	Federal System (BPA)	400
Dworshak/ Clearwater		Federal System (BPA)	3
Eagle Point	PacifiCorp	PacifiCorp	3
East Side	PacifiCorp	PacifiCorp	3
Eight Mile Hydro	PURPA	Idaho Power	0.4
Elk Creek	PURPA	Idaho Power	3
Eltopia Branch Canal[2]	Columbia Basin Hydro	Multiple Utilities	2
Esquatzel Small Hydro	Green Energy Today, LLC	Franklin County PUD	1
Fall Creek	PacifiCorp	PacifiCorp	3
Falls Creek	Clallam PUD	Other Public (BPA)	0.03
Fall River	PURPA	Idaho Power	9
Faraday	Portland General Electric	Portland General Electric	37
Fargo Drop Hydro	PURPA	Idaho Power	1

Project	Owner	NW Utility	Nameplate (MW)
Farmers Irrigation	PacifiCorp	PacifiCorp	3
Faulkner Ranch	PURPA	Idaho Power	1
Fish Creek	PacifiCorp	PacifiCorp	11
Fisheries Development Co.	PURPA	Idaho Power	0.3
Foster	US Corps of Engineers	Federal System (BPA)	20
Frontier Technologies	PacifiCorp	PacifiCorp	4
Galesville Dam	PacifiCorp	PacifiCorp	2
Gem State Hydro		Other Publics (BPA)	23
Geo-Bon No 2	PURPA	Idaho Power	1
Georgetown Power	PacifiCorp	PacifiCorp	0.4
Gorge	Seattle City Light	Seattle City Light	207
Grand Coulee	US Bureau of Reclamation	Federal System (BPA)	6,494
Green Peter	US Corps of Engineers	Federal System (BPA)	80
Green Springs	US Bureau of Reclamation	Federal System (BPA)	16
Hailey CSPP	PURPA	Idaho Power	0.1
Hancock Creek	Snohomish County PUD	Snohomish County PUD	6
Hauser	NorthWestern Energy	NorthWestern Energy	19
Hazelton A	PURPA	Idaho Power	8
Hazelton B	PURPA	Idaho Power	8
Head of U Canal	PURPA	Idaho Power	1
Hells Canyon	Idaho Power	Idaho Power	392
Hills Creek	US Corps of Engineers	Federal System (BPA)	30
Holter	NorthWestern Energy	NorthWestern Energy	53
Hood Street Reservoir	Tacoma Power	Tacoma Power	1
Horseshoe Bend	PURPA	Idaho Power	9
Hungry Horse	US Bureau of Reclamation	Federal System (BPA)	428
Ice Harbor	US Corps of Engineers	Federal System (BPA)	603
Idaho Falls - City Plant		Federal System (BPA)	8
Idaho Falls - Lower Plant		Federal System (BPA)	8
Idaho Falls - Upper Plant		Federal System (BPA)	8
Ingram Warm Springs	PacifiCorp	PacifiCorp	1
Iron Gate	PacifiCorp	PacifiCorp	18
Island Park		Fall River Rural Elect. Co-op	5
Jackson (Sultan)	Snohomish County PUD	Snohomish County PUD	112
James Boyd		PacifiCorp	0.2
Jim Ford Creek	Ford Hydro	Avista Corp.	2
Jim Knight	PURPA	Idaho Power	0.3
John C. Boyle	PacifiCorp	PacifiCorp	90
John Day	US Corps of Engineers	Federal System (BPA)	2,160
John Day Creek	Dave Cereghino	Avista Corp.	1
Koyle Small Hydro	PURPA	Idaho Power	1
Joseph Hydro		PacifiCorp	1
MC6 Hydro	PURPA	Idaho Power	2

Project	Owner	NW Utility	Nameplate (MW)
Koma Kulshan	Koma Kulshan Associates	Puget Sound Energy	12
La Grande	Tacoma Power	Tacoma Power	64
Lacomb Irrigation	PacifiCorp	PacifiCorp	1
Lake Oswego Corp.		Portland General Electric	1
Lateral No. 10	PURPA	Idaho Power	2
Leaburg	Eugene Water & Electric Board	Eugene Water & Electric Board	16
Lemolo #1	PacifiCorp	PacifiCorp	32
Lemolo #2	PacifiCorp	PacifiCorp	33
Lemoyne	PURPA	Idaho Power	0.1
Libby	US Corps of Engineers	Federal System (BPA)	525
Lilliwaup Falls		Other Public (BPA)	1
Little Falls	Avista Corp.	Avista Corp.	32
Little Goose	US Corps of Engineers	Federal System (BPA)	810
Little Wood Rvr Res	PURPA	Idaho Power	3
Little Wood/Arkoosh	PURPA	Idaho Power	1
Little Wood River Ranch II	PURPA	Idaho Power	1
Lloyd Fery	PacifiCorp	PacifiCorp	0.04
Long Lake	Avista Corp.	Avista Corp.	70
Lookout Point	US Corps of Engineers	Federal System (BPA)	120
Lost Creek	US Corps of Engineers	Federal System (BPA)	49
Lower Baker	Puget Sound Energy	Puget Sound Energy	111
Lower Granite	US Corps of Engineers	Federal System (BPA)	810
Lower Malad	Idaho Power	Idaho Power	14
Lower Monumental	US Corps of Engineers	Federal System (BPA)	810
Lower Salmon	Idaho Power	Idaho Power	60
Lowline #2	PURPA	Idaho Power	3
Low Line Canal	PURPA	Idaho Power	8
Low Line Midway	PURPA	Idaho Power	3
Lucky Peak	US Corps of Engineers	Seattle City Light	113
Madison	Northwestern Energy	NorthWestern Energy	13
Magic Reservoir	PURPA	Idaho Power	9
Main Canal Headworks[2]	Columbia Basin Hydro	Multiple Utilities	26
Malad River	PURPA	Idaho Power	1
Mayfield	Tacoma Power	Tacoma Power	162
McNary	US Corps of Engineers	Federal System (BPA)	980
McNary Fishway	US Corps of Engineers	Other Publics (BPA)	10
Merwin	PacifiCorp	PacifiCorp	136
Meyers Falls	Hydro Technology Systems	Avista Corp.	1
Middlefork Irrigation	PacifiCorp	PacifiCorp	3
Mile 28	PURPA	Idaho Power	2
Mill Creek		Other Publics (BPA)	1

Project	Owner	NW Utility	Nameplate (MW)
Milner	Idaho Power	Idaho Power	60
Minidoka	US Bureau of Reclamation	Federal System (BPA)	28
Mink Creek	PacifiCorp	PacifiCorp	3
Mitchell Butte	PURPA	Idaho Power	2
Monroe Street	Avista	Avista Corp.	15
Mora Drop	PURPA	Idaho Power	2
Morony	NorthWestern Energy	NorthWestern Energy	49
Morse Creek		Port Angeles	1
Mossyrock	Tacoma Power	Tacoma Power	300
Mountain Energy	PacifiCorp	PacifiCorp	0.1
Mount Tabor	City of Portland	Portland General Electric	0.2
Moyie Springs	City of Bonners Ferry	Other Publics (BPA)	4
Mud Creek/S&S	PURPA	Idaho Power	1
Mud Creek/White	PURPA	Idaho Power	0.2
Mystic	NorthWestern Energy	NorthWestern Energy	73
N-32 Canal (Marco Ranches)	PURPA	Idaho Power	12
Nicols Gap	PacifiCorp	PacifiCorp	1
Nicolson SunnyBar	PacifiCorp	PacifiCorp	0.4
Nine Mile	Avista Corp.	Avista Corp.	26
Nooksack	Puget Sound Hydro, LLC	Puget Sound Energy	-
North Gooding Main Hydro		Idaho Power	1
North Fork	Portland General Electric	Portland General Electric	41
North Fork Sprague	PacifiCorp	PacifiCorp	1
N.R. Rousch	PacifiCorp	PacifiCorp	0.1
Noxon Rapids	Avista Corp.	Avista Corp.	466
Odell Creek	PacifiCorp	PacifiCorp	0.2
Oak Grove	Portland General Electric	Portland General Electric	51
O.J. Power	PacifiCorp	PacifiCorp	0.3
Opal Springs	PacifiCorp	PacifiCorp	5
Owyhee Dam	PURPA	Idaho Power	5
Oxbow	Idaho Power Company	Idaho Power	190
Packwood	Energy Northwest	Multiple Utilities	26
Palisades	US Bureau of Reclamation	Federal System (BPA)	177
PEC Headworks[2]	Columbia Basin Hydro	Multiple Utilities	6.60
Pelton Reregulation	Warm Springs Tribe	Portland General Electric	19
Pelton	Portland General Electric	Multiple Utilities	110
Phillips Ranch	Glen Phillips	Avista Corp.	0.02
Pigeon Cove	PURPA	Idaho Power	2
Portneuf River		PacifiCorp	1
Potholes East Canal 66 Headworks[2]	Columbia Basin Hydro	Multiple Utilities	2
Post Falls	Avista Corp.	Avista Corp.	15
Preston City	PacifiCorp	PacifiCorp	0.40

Project	Owner	NW Utility	Nameplate (MW)
Powerdale	PacifiCorp	PacifiCorp	6
Pristine Springs	PURPA	Idaho Power	0.1
Priest Rapids	Grant County PUD	Multiple Utilities	956
Pristine Springs #3	PURPA	Idaho Power	0.2
Prospect projects	PacifiCorp	PacifiCorp	44
Quincy Chute[2]	Columbia Basin Hydro	Multiple Utilities	9
R.D. Smith[2]	Columbia Basin Hydro	Multiple Utilities	6
Reynolds Irrigation	PURPA	Idaho Power	0.3
Reeder Gulch	City of Ashland	Other Publics (BPA)	0.1
River Mill	Portland General Electric	Portland General Electric	19
Rock Creek No. 1	PURPA	Idaho Power	2
Rock Creek No. 2	PURPA	Idaho Power	2
Rocky Brook	Mason County PUD #3	Other Public (BPA)	2
Rainbow	NorthWestern Energy	NorthWestern Energy	59
Rock Island	Chelan County PUD	Multiple Utilities	629
Rocky Reach	Chelan County PUD	Multiple Utilities	1,300
Ross	Seattle City Light	Seattle City Light	450
Round Butte	Portland General Electric	Multiple Utilities	247
Roza	US Bureau of Reclamation	Federal System (BPA)	13
Ryan	NorthWestern Energy	NorthWestern Energy	71
Sagebrush	PURPA	Idaho Power	0.4
Sahko	PURPA	Idaho Power	1
Santiam	PacifiCorp	PacifiCorp	0.2
Schaffner	PURPA	Idaho Power	1
Seli'š Ksanka Qlispe'	Conf. Salish/Kootenai Tribes	NorthWestern Energy	194
Sheep Creek	Glen Phillips	Avista Corp.	2
Shoshone II	PURPA	Idaho Power	1
Shoshone CSPP	PURPA	Idaho Power	0.4
Slide Creek	PacifiCorp	PacifiCorp	18
Shoshone Falls	Idaho Power	Idaho Power	14
Soda Springs	PacifiCorp	PacifiCorp	11
Smith Creek	Smith Creek Hydro, LLC	Eugene Water & Electric Board	38
Snedigar Ranch	PURPA	Idaho Power	1
Snoqualmie Falls	Puget Sound Energy	Puget Sound Energy	54
Spokane Upriver	City of Spokane	Avista Corp.	16
Soda Creek	City of Soda Springs	Other Publics (BPA)	1
Snake River Pottery	PURPA	Idaho Power	0.1
South Fork Tolt	Seattle City Light	Seattle City Light	17
Stauffer Dry Creek		PacifiCorp	1
Summer Falls[2]	Columbia Basin Hydro	Multiple Utilities	92
Stone Creek	Eugene Water & Electric Board	Eugene Water & Electric Board	12
Strawberry Creek	South Idaho Public Agency	Other Publics (BPA)	2
Sygitowicz	Cascade Clean Energy	Puget Sound Energy	0.4

Project	Owner	NW Utility	Nameplate (MW)
Swan Falls	Idaho Power	Idaho Power	25
Swift 1	PacifiCorp	Multiple Utilities	219
Swift 2	Cowlitz County PUD	Multiple Utilities	73
TGS/Briggs		PacifiCorp	0.2
Tiber Dam	PURPA	Idaho Power	8
The Dalles	US Corps of Engineers	Federal System (BPA)	1,807
The Dalles Fishway	Northern Wasco Co. PUD	Northern Wasco Co. PUD	5
Thompson Falls	NorthWestern Corporation	NorthWestern Energy	94
Thousand Springs	Idaho Power	Idaho Power	9
Toketee	PacifiCorp	PacifiCorp	43
Trout Company	PURPA	Idaho Power	0.2
Trail Bridge	Eugene Water & Electric Board	Eugene Water & Electric Board	10
Tunnel #1	PURPA	Idaho Power	7
Turnbull Hydro		NorthWestern Energy	7
Twin Falls	PURPA	Puget Sound Energy	20
Twin Falls	Idaho Power	Idaho Power	53
TW Sullivan	Portland General Electric	Portland General Electric	15
Upper Baker	Puget Sound Energy	Puget Sound Energy	105
Upper Falls	Avista Corp.	Avista Corp.	10
Upper Malad	Idaho Power	Idaho Power	8
Upper Salmon 1 & 2	Idaho Power	Idaho Power	18
Upper Salmon 3 & 4	Idaho Power	Idaho Power	17
Walla Walla	PacifiCorp	PacifiCorp	2
Weeks Falls	So. Fork II Assoc. LP	Puget Sound Energy	5
Wallowa Falls	PacifiCorp	PacifiCorp	1
Walterville	Eugene Water & Electric Board	Eugene Water & Electric Board	8
Wanapum	Grant County PUD	Multiple Utilities	934
West Side	PacifiCorp	PacifiCorp	1
Wells	Douglas County PUD	Multiple Utilities	774
White Water Ranch	PURPA	Idaho Power	0.2
Clark Canyon Dam	PURPA	Idaho Power	8
Woods Creek	Snohomish County PUD	Snohomish County PUD	1
Yakima-Tieton	PacifiCorp	PacifiCorp	3
Wynoochee	Tacoma Power	Tacoma Power	13
Yale	PacifiCorp	PacifiCorp	134
Yelm		Other Publics (BPA)	12
Youngs Creek	Snohomish County PUD	Snohomish County PUD	8

[2] Avista Corp. signed contract agreement with Columbia Basin Hydro to purchase project generation as existing contracts expire with Seattle City Light, Tacoma Power and Grant PUD.

Project	Owner	NW Utility	Nameplate (MW)
COAL			**3,907**
Colstrip #3	PP&L Montana, LLC	Multiple Utilities	740
Colstrip #4	NorthWestern Energy	Multiple Utilities	740
Jim Bridger #1	PacifiCorp / Idaho Power	Multiple Utilities	540
Jim Bridger #2	PacifiCorp / Idaho Power	Multiple Utilities	540
Jim Bridger #3	PacifiCorp / Idaho Power	Multiple Utilities	540
Jim Bridger #4	PacifiCorp / Idaho Power	Multiple Utilities	540
Valmy #2	NV Energy / Idaho Power	Multiple Utilities	267
NUCLEAR			**1,230**
Columbia Generating Station	Energy Northwest	Federal System (BPA)	1,230
NATURAL GAS			**7,001**
Alden Bailey	Clatskanie PUD	Clatskanie PUD	11
Basin Creek	NorthWestern Energy	NorthWestern Energy	52
Beaver	Portland General Electric	Portland General Electric	486
Beaver 8	Portland General Electric	Portland General Electric	23
Bennett Mountain	Idaho Power	Idaho Power	173
Boulder Park	Avista	Avista	25
Carty	Portland General Electric	Portland General Electric	437
Chehalis	PacifiCorp	PacifiCorp	491
Coyote Springs I	Portland General Electric	Portland General Electric	252
Coyote Springs II	Avista	Avista	287
Danskin	Idaho Power	Idaho Power	92
Danskin 1	Idaho Power	Idaho Power	179
Dave Gates	NorthWestern Energy	NorthWestern Energy	150
Encogen	Puget Sound Energy	Puget Sound Energy	166
Ferndale	Puget Sound Energy	Puget Sound Energy	244
Frederickson	EPCOR Power L.P./PSE	Multiple Utilities	258
Fredonia 1 & 2	Puget Sound Energy	Puget Sound Energy	234
Fredonia 3 & 4	Puget Sound Energy	Puget Sound Energy	108
Fredrickson 1 & 2	Puget Sound Energy	Puget Sound Energy	149
Goldendale	Puget Sound Energy	Puget Sound Energy	280
Hermiston GP	PacifiCorp/Hermiston Generating	PacifiCorp	468
Kettle Falls CT	Avista	Avista	7
Lancaster Power Project	Avista	Avista	270
Langley Gulch	Idaho Power	Idaho Power	319
Laurel Generating Station	NorthWestern Energy	NorthWestern Energy	175
Mint Farm Energy Center	Puget Sound Energy	Puget Sound Energy	276
Northeast A&B	Avista	Avista	62
Port Westward	Portland General Electric	Portland General Electric	411
Port Westward Unit 2	Portland General Electric	Portland General Electric	225
Rathdrum 1 & 2	Avista	Avista	167

Project	Owner	NW Utility	Nameplate (MW)
River Road	Clark Public Utilities	Clark Public Utilities	248
Sumas Energy	Puget Sound Energy	Puget Sound Energy	129
Whitehorn #2 & #3	Puget Sound Energy	Puget Sound Energy	149
COGENERATION			**119**
Billings Cogeneration	Billings Generation, Inc.	NorthWestern Energy	64
Hampton Lumber	Hampton Lumber Mills	Snohomish County PUD PPA	5
International Paper Energy Center	Eugene Water & Electric Board	Eugene Water & Electric Board	26
Port Townsend Mill	Port Townsend Paper	BPA (other publics)	8
Simplot-Pocatello	PURPA	Idaho Power	12
Tasco-Nampa	Tasco	Idaho Power	2
Tasco-Twin Falls	Tasco	Idaho Power	3
RENEWABLES-OTHER			**402**
Bannock County Landfill	PURPA	Idaho Power	3
Bettencourt Dry Creek	PURPA	Idaho Power	2
Biomass One	PacifiCorp	PacifiCorp	25
Bloks Evergreen Dairy	Puget Sound Energy	Puget Sound Energy	0
DR Johnson Lumber	PacifiCorp	PacifiCorp	8
Columbia Ridge Landfill	Waste Management	Seattle City Light	13
Dry Creek Landfill	Dry Creek Landfill Inc.	PacifiCorp	3
Emerald City I		Puget Sound Energy	5
Emerald City II		Puget Sound Energy	5
Fighting Creek	PURPA	Idaho Power	3
Flathead County Landfill	Flathead Electric Cooperative	Flathead Electric Cooperative	2
Hidden Hollow Landfill	PURPA	Idaho Power	3
H. W. Hill Landfill	Allied Waste Companies	Multiple Utilities	37
Interfor Pacific-Gilchrist	Midstate Electric Co-op	Midstate Electric Co-op	2
Kettle Falls	Avista Corp.	Avista Corp.	51
Neal Hot Springs	U.S Geothermal	Idaho Power	33
Pico Energy, LLC	PURPA	Idaho Power	2
Pine Products	PacifiCorp	PacifiCorp	6
Plum Creek NLSL	Plum Creek MDF	Flathead Electric Cooperative	6
Pocatello Wastewater	PURPA	Idaho Power	0.5
Port of Tillamook Digester		Tillamook PUD	1
PGE non solar QFs		Portland General Electric	73
Qualco Dairy Digester		Snohomish PUD	0.7
Raft River 1	US Geothermal	Idaho Power	16
River Bend Landfill	McMinnville Water & Light	McMinnville Water & Light	5
Rock Creek Dairy	PURPA	Idaho Power	3
Seneca	Seneca Sustainable Energy, LLC	Eugene Water & Electric Board	20
Short Mountain		Emerald PUD	3
Sierra Pacific		Grays Harbor	16

Project	Owner	NW Utility	Nameplate (MW)
SPI Biomass		Puget Sound Energy	17
Spokane Waste Energy	City of Spokane	Avista Corp.	26
Stimson Lumber	Stimson Lumber	Avista	7
Stoltze Biomass	F.H. Stoltze Land & Lumber	Flathead Electric Cooperative	3
Tamarack	PURPA	Idaho Power	5
Whitefish Hydro	City of Whitefish	Flathead Electric Cooperative	0.2
SOLAR			**2,472**
Adams Solar Center		PacifiCorp	10
American Falls Solar	PURPA	Idaho Power	20
American Falls Solar II	PURPA	Idaho Power	20
Ashland Solar Project		BPA	0.1
Baker Solar	PURPA	Idaho Power	15
Bear Creek		PacifiCorp	10
Bellevue Solar	EDF Renewable Energy	Portland General Electric	2
Black Eagle Solar		NorthWestern Energy	3
Black Cap		PacifiCorp	2
Black Cap II		PacifiCorp	8
Bly Solar Center		PacifiCorp	9
Cleanera Apex I		NorthWestern Energy	80
Brush Solar	PURPA	Idaho Power	3
Captain Jack Solar		PacifiCorp	3
Chiloquin		PacifiCorp	10
Collier		PacifiCorp	10
Daybreak Solar		Portland General Electric	138
Durkee Solar	PURPA	Idaho Power	3
Elbe		PacifiCorp	10
Ewauna (I & II)		PacifiCorp	4
Grand View Solar	PURPA	Idaho Power	80
Great Divide Solar		NorthWestern Energy	3
Green Meadows Solar		NorthWestern Energy	3
Grove Solar	PURPA	Idaho Power	6
Horn Rapids		Energy Northwest	3
Hyline Solar Center	PURPA	Idaho Power	9
ID Solar 1	Boise City Solar, LLC	Idaho Power	40
IKEA Solar		Puget Sound Energy	1
Jackpot Solar	Jackpot Holdings, LLC	Idaho Power	120
King Estate Solar	Lane Co. Electric Cooperative	Lane Co. Electric Cooperative	0.2
Lund Hill	Lane Co. Electric Cooperative	Puget Sound Energy	150
Magpie Solar		NorthWestern Energy	3
Merrill Solar LLC		PacifiCorp	10
Millican Solar Energy		PacifiCorp	60
Moore's Hollow	PURPA	Idaho Power	42
Morgan Solar	PURPA	Idaho Power	3

Project	Owner	NW Utility	Nameplate (MW)
Mountain Home Solar	PURPA	Idaho Power	20
Moyer-Tolles Solar	Umatilla Electric Cooperative	Umatilla Electric Cooperative	1
MTSun LLC		NorthWestern Energy	80
Murphy Flat Power	PURPA	Idaho Power	20
Neilson Solar		Avista	19
Norwest Projects		PacifiCorp	32
Old Mill		PacifiCorp	5
Ontario Solar Center	PURPA	Idaho Power	3
Open Range Solar Center	PURPA	Idaho Power	10
Orchard Ranch Solar	PURPA	Idaho Power	20
OR Solar projects		PacifiCorp	58
OSIP		PacifiCorp	10
Pachwáywit Solar		Portland General Electric	162
Prairie City	PURPA	Idaho Power	29
PGE QF Solar		Portland General Electric	528
Prineville		PacifiCorp	40
PSE Small Solar Projects		Puget Sound Energy	15
Railroad Solar Center	PURPA	Idaho Power	5
River Bend Solar		NorthWestern Energy	3
Simco Solar	PURPA	Idaho Power	20
South Mills Solar 1		NorthWestern Energy	3
Solarize Rogue LLC	Oregon Clean Power	PacifiCorp	0
Sunnyside Solar	OneEnergy Renewables	PacifiCorp	5
Thunderegg Solar Center	PURPA	Idaho Power	10
Tumbleweed		PacifiCorp	10
Vale I Solar	PURPA	Idaho Power	3
Vale Air Solar	PURPA	Idaho Power	10
Wasco Co Solar		Portland General Electric	60
Wheatridge Solar	Portland General/NextEra Energy	PGE/NextEra	50
WIND			**6,100**
71 Ranch LP		NorthWestern Energy	3
Bennett Creek	PURPA	Idaho Power	21
Benson Creek Wind	PURPA	Idaho Power	10
Big Timber Wind		NorthWestern Energy	25
Biglow Canyon - 1	Portland General Electric	Portland General Electric	125
Biglow Canyon - 2	Portland General Electric	Portland General Electric	163
Biglow Canyon - 3	Portland General Electric	Portland General Electric	161
Burley Butte Wind Farm	PURPA	Idaho Power	21
Camp Reed Wind Park	PURPA	Idaho Power	23
Cassia Wind Farm	PURPA	Idaho Power	11
Chopin		PacifiCorp	10
Clearwater	NextEra	Multiple Utilities	661
Coastal Energy	CCAP	Grays Harbor PUD	6

Project	Owner	NW Utility	Nameplate (MW)
Cold Springs	PURPA	Idaho Power	23
Combine Hills I	Eurus Energy of America	PacifiCorp	41
Combine Hills II	Eurus Energy of America	Clark Public Utilities	63
Condon Wind	Goldman Sachs/SeaWest NW	Federal System (BPA)	25
Cycle Horseshoe Bend Wind		NorthWestern Energy	9
DA Wind Investors		NorthWestern Energy	3
Desert Meadow Windfarm	PURPA	Idaho Power	23
Durbin Creek	PURPA	Idaho Power	10
Elkhorn Wind	Telocaset Wind Power Partners	Idaho Power	101
Fairfield Wind		NorthWestern Energy	10
Fossil Gulch Wind	PURPA	Idaho Power	11
Golden Hills	Avangrid	Puget Sound Energy	200
Golden Valley Wind Farm	PURPA	Idaho Power	12
Goodnoe Hills	PacifiCorp	PacifiCorp	94
Gordon Butte Wind		NorthWestern Energy	10
Greenfield Wind		NorthWestern Energy	25
Hammett Hill Windfarm	FALSE	Idaho Power	23
Harvest Wind	Summit Power	Multiple Utilities	99
Hay Canyon Wind	Hay Canyon Wind Project LLC (Iberdrola)	Snohomish County PUD	101
High Mesa Wind	PURPA	Idaho Power	40
Hopkins Ridge	Puget Sound Energy	Puget Sound Energy	157
Horseshoe Bend	PURPA	Idaho Power	9
Hot Springs Wind	Hot Springs Wind	Idaho Power	21
Jett Creek	PURPA	Idaho Power	10
Judith Gap	Invenergy Wind, LLC	NorthWestern Energy	135
Klondike II	PPM Energy	Portland General Electric	75
Klondike III	PPM Energy	Multiple Utilities	221
Leaning Juniper 1	PPM Energy	PacifiCorp	101
Lime Wind Energy	PURPA	Idaho Power	3
Lower Snake River 1	Puget Sound Energy	Puget Sound Energy	342
Mainline Wind Farm	PURPA	Idaho Power	23
Marengo	Renewable Energy America	PacifiCorp	140
Marengo II	PacifiCorp	PacifiCorp	70
Mariah Wind		PacifiCorp	10
Milner Dam Wind Farm	PURPA	Idaho Power	20
Musselshell Wind 1		NorthWestern Energy	10
Musselshell Wind 2		NorthWestern Energy	10
Nine Canyon	Energy Northwest	Multiple Utilities	96
NWE small Wind aggregate		NorthWestern Energy	5
Orchard Wind		PacifiCorp	40
Oregon Wind Farms I & II		PacifiCorp	65
Oregon Trails Wind Farm	PURPA	Idaho Power	14

Project	Owner	NW Utility	Nameplate (MW)
Orem Family Wind		PacifiCorp	10
Oversight Resources		NorthWestern Energy	3
Palouse Wind	Palouse Wind, LLC	Avista Corp.	105
Paynes Ferry Wind Park	PURPA	Idaho Power	21
Pilgrim Stage Station	PURPA	Idaho Power	11
Prospector Wind	PURPA	Idaho Power	10
Rattlesnake Flat Wind		Avista Corp.	146
Rockland Wind	PURPA	Idaho Power	80
Ryegrass Windfarm	PURPA	Idaho Power	23
Salmon Falls Wind Farm	PURPA	Idaho Power	22
Sawtooth Wind	PURPA	Idaho Power	22
Skookumchuck	Puget Sound Energy	Puget Sound Energy	137
Stateline Wind	NextEra	Multiple Utilities	275
Stillwater Wind		NorthWestern Energy	80
South Peak Wind		NorthWestern Energy	80
Spion Kop Wind		NorthWestern Energy	40
Thousand Springs	PURPA	Idaho Power	12
Three Mile Canyon	Momentum RE	PacifiCorp	10
Tuana Gulch Wind Farm	PURPA	Idaho Power	11
Tuana Springs Expansion	PURPA	Idaho Power	36
Tucannon	Portland General Electric	Portland General Electric	267
Two Dot Wind		NorthWestern Energy	11
Two Ponds Windfarm	PURPA	Idaho Power	23
Vansycle Ridge	ESI Vansycle Partners	Portland General Electric	25
Wheat Field Wind Project	Wheat Field Wind LLC	Snohomish County PUD	97
Wheatridge Wind Project	PGE/Nextera Energy	Portland General Electric	300
White Creek	White Creek Wind I LLC	Multiple Utilities	205
Wild Horse	Puget Sound Energy	Puget Sound Energy	273
Willow Spring Windfarm	PURPA	Idaho Power	10
Yahoo Creek Wind Park	PURPA	Idaho Power	21
SMALL THERMAL AND MISCELLANEOUS			**299**
Bangor Base 1&2	US Navy-Bangor	BPA/Other publics	18
Yellowstone Energy LP	Yellowstone Energy Limited Partnership	Northwestern Energy	52
Crystal Mountain	Puget Sound Energy	Puget Sound Energy	3
Li-Ion Battery Energy Storage		Snohomish PUD	50
PGE DSG		Portland General Electric	127
Puget Sound Shipyard	U.S. Navy-Bangor	BPA/Other publics	12
Wheatridge Battery	PGE/NextEra	Portland General Electric	30
Total Generating Resources Nameplate MW			**55,354**

Table 11. Independent Owned Generating Resources is a partial list of independently owned electric power supply located in the region. Some of these units have partial contracts (reflected in the load/resource tables) with Northwest utilities. PNUCC does not collect data from independent power producers (IPPs) – this is information gathered from various sources including Bonneville Power and the NW Power & Conservation Council.

Project	Owner	Nameplate (MW)
HYDRO		**90**
Big Creek (Hellroaring)		-
Electron	Electron Hydro, LLC	24
Felt	CDM Hydro	7.4
PEC Headworks	Columbia Basin Hydro	7
Soda Point Project		-
Sygitowicz	Cascade Clean Energy	0.5
Owyhee Tunnel No.1	Owyhee Irrigation District	8
Portland Hydro Project		36
Wilson Lake	Hazelton/Wilson	8.4
COAL		**924**
Centralia #2	TransAlta	670
Valmy #1	NV Energy	254
NATURAL GAS		**2,081**
Grays Harbor (Satsop)	Invenergy	650
Hermiston Power Project	Hermiston Power Partners (Calpine)	689
Klamath Cogen Plant	Iberdrola Renewables	502
Klamath Peaking Units 1-4	Iberdrola Renewables	100
March Point 1	March Point Cogen	80
March Point 2	March Point Cogen	60
COGENERATION		**268**
Boise Cascade		9
Clearwater Paper	Clearwater Paper	94
Cosmo Fibers TG1	Cosmo	8
Cosmo Fibers TG2	Cosmo	8
Freres Lumber	Evergreen BioPower	10
Plummer Forest		6
Rough & Ready Lumber	Rough & Ready	1
Simpson CoGen		55
Warm Springs Forest		8
Wauna	Western Generation Agency	36
Weyerhaeuser TG 1	Weyerhaeuser	5
Weyerhaeuser TG 1	Weyerhaeuser	5
RENEWABLES-OTHER		**26**
Spokane MSW	City of Spokane	23
Treasure Valley		3

Project	Owner	Nameplate (MW)
SOLAR		**56**
Gala Solar Farm		56
WIND		**3,695**
Big Horn	Iberdrola Renewables	199
Big Horn-Phase 2	Iberdrola Renewables	50
Big Top		2
Butter Creek Power	Butter Creek Power LLC	5
Campbell Hill		99
Cassia Gulch	John Deere	21
Chevron Casper	Chevron	17
Foote Creek III		25
Four Corners Windfarm	Four Corners Windfarm LLC	10
Four Mile Canyon Windfarm	Four Mile Canyon Windfarm LLC	10
Glacier Wind - Phase 1	Naturener	107
Glacier Wind - Phase 2	Naturener	104
Goshen North	Ridgeline Energy	125
Juniper Canyon - Phase 1	Iberdrola Renewables	151
Kittitas Valley	Horizon	101
Klondike IIIa	Iberdrola Renewables	77
Lava Beds Wind		18
Leaning Juniper II-North	Iberdrola Renewables	90
Leaning Juniper II-South	Iberdrola Renewables	109
Linden Ranch	NW Wind Partners	50
Magic Wind Park		20
Martinsdale Colony North	Two Dot Wind	1
Martinsdale Colony South	Two Dot Wind	2
Montague Wind	Avangrid for Apple	202
Notch Butte Wind		18
Pacific Canyon Windfarm	Pacific Canyon Windfarm LLC	8
Pebble Springs Wind	Iberdrola Renewables	99
Rattlesnake Rd Wind	Horizon Wind	103
Rock River I	Shell Wind Energy	50
Sand Ranch Windfarm	Sand Ranch Windfarm LLC	10
Shepherds Flat Central	Caithness Energy	290
Shepherds Flat North	Caithness Energy	265
Shepherds Flat South	Caithness Energy	290
Stateline Wind	NextEra	300
Vancycle II (Stateline III)	NextEra	99
Vantage Wind	Invenergy	90
Wagon Trail Windfarm	Wagon Trail Windfarm LLC	3
Ward Butte Windfarm	Ward Butte Windfarm LLC	7
Willow Creek	Invenergy	72
Windy Flats	Cannon Power Group	262
Windy Point	Tuolumne Wind Project Authority	137
Independent Owned Total Nameplate MW		**7,139**

Report Description

This report provides a regional firm needs estimate over the ten-year study period for annual energy (August through July, *Table 1*), monthly energy (*Table 2*), winter peak-hour (*Table* 3) and summer peak-hour (*Table 4*). The monthly energy picture is provided to underscore the variability of the power need within an average year. The peak need reflects information for January and August, as they present the greatest need for their respective seasons. These metrics provide a multi-dimensional look at the Northwest's need for power and underscore the growing complexity of the power system.

This information reflects the summation of individual utilities' load forecasts and generating resources expected to meet their load, as well as the total of utilities committed and planned resources to meet future needs and policy requirements. The larger utilities, in most cases, prepare their own projections for their integrated resource plans. Bonneville Power Administration (BPA) provides much of the information for its smaller customers. This section includes procedures used in preparing the load resource comparisons, a list of definitions, and a list of the utilities summarized by this report (*Table 12*).

Load Estimate

Regional loads are the sum of demand estimated by the Northwest utilities and BPA for its federal agency customers and certain non-generating public utilities. Direct service industrial customers are no longer a significant part of regional load. Utilities are asked to provide their native load forecast. Load projections include network transmission and distribution losses and are net of existing and forecasted energy efficiency savings (including codes & standards). Demand response program savings are not reflected in loads, rather they are included on the supply side in this report. Since the *Forecast* is completed annually, utilities may provide load forecasts that are updated and out of sync with their last integrated resource plan.

Energy Loads

Northwest firm energy loads are provided for each month of the ten-year forecast period. This forecast reflects normal (1-in-2) weather conditions.

Peak Loads

Northwest regional peak loads are provided for each month of the ten-year forecast period. The tabulated loads for winter and summer peak are the highest estimated hourly loads for that month, assuming normal (1-in-2) weather conditions. The regional firm peak load is the sum of the individual utilities' peak loads and does not account for a utility potentially experiencing a peak load at a different day/hour than other Northwest utilities. Hence the regional peak load is considered non-coincident. The federal system (BPA) firm peak load is adjusted to reflect a federal coincident peak among its many utility customers.

Federal System Transmission Losses

Federal System (BPA) transmission losses for both firm loads and contractual obligations are embedded in federal load. These losses represent the difference between energy generated by the federal system (or delivered to a system interchange point) and the amount of energy sold to customers. System transmission losses are calculated by BPA for firm loads utilizing the federal transmission system.

Planning Margin

In the derivation of regional peak requirements, a planning margin is included. The planning margin is set to 16 percent of the total peak load for every year of the planning horizon.[1]

This planning margin is intended to cover, for planning purposes, operating reserves and all elements of uncertainty not specifically accounted for in determining loads and resources. These include forced-outage reserves, unanticipated load growth, temperature variations, hydro maintenance, and project construction delays.

Demand-Side Management Programs

Savings from demand-side management (*Table 7*) are for the ten-year study period and include data provided by utilities such as utility energy efficiency programs, some market transformation, and other efforts that reduce the demand for electricity. These estimates reflect savings from programs that utilities fund directly, or through a third-party, such as the Northwest Energy Efficiency Alliance and Energy Trust of Oregon.

Demand response programs are also tallied on *Table 7* showing the programs' winter peak and summer peak contributions to need. The regional demand response data is from the cumulative sum of all utilities' agreements with their customers (for both existing and future programs). Each program has its own characteristics and limitations that are reflected in the data provided.

Generating Resources

This report catalogues existing resources, committed new supply (including resources under construction), and planned future resources. For the assessment of need, only the existing and committed resources are reflected in the regional tabulations. In addition, only those generating resources (or shares) that are firmly committed to meeting Northwest loads are included in the regional analysis. A list of all resources included in the report load/resource tabulations is in *Table 10*.

[1] When making comparisons to *Northwest Regional Forecasts* prior to 2018, be aware that the planning margin was previously set at 12 percent for the first year of the report and grew a percent a year until it reached 20 percent and remained at 20 percent thereafter. This escalation was in part to address uncertainty of planning for generating resources with long planning and construction lead times.

Hydro

Major hydro resource capabilities are estimated from a regional analysis using computer models that simulate reservoir operation of past hydrologic conditions with today's operating constraints and requirements. New for the 2023 *Forecast* is the availability of ten more years of the historical stream flow record. The data available covers the 90-year period from August 1928 through July 2018. The bulk of the hydro modeling used in this report is provided by BPA, the US Army Corps of Engineers, and/or project owners/sponsors.

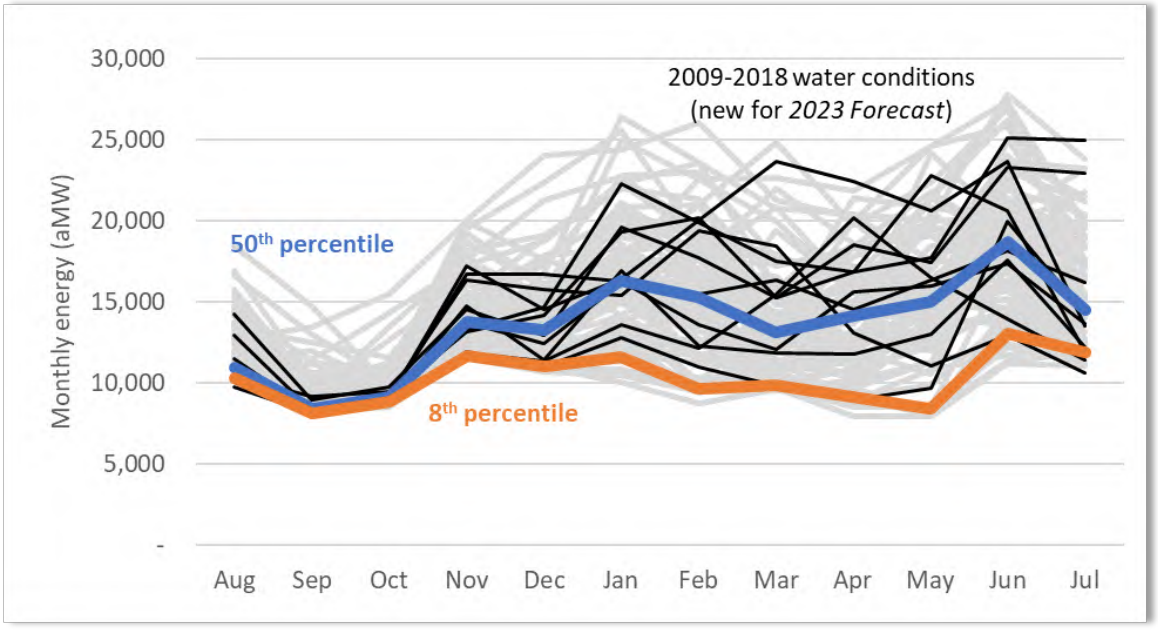
Annual and Monthly Energy

The bulk of the hydro energy data in this report comes from the US Army Corps of Engineers. Generation for projects that are influenced by downstream reservoirs reflects the reduction due to encroachment. New this year, the firm energy capability of hydro plants is the amount of energy produced using the 8th percentile monthly energy production from the 90-year historical river flow given today's river operating criteria. This provides an updated view of the critically low value for planning. The firm annual energy capability is the average of the 8th percentile monthly generation for the 90-year period. This synthetic water year ensures each month and year are evaluated similarly and under critically low streamflow.

Variability of Hydro

The variability of hydro generation is due to the hydrology of the river systems in the Northwest. Monthly hydro energy generation estimates from the major developments in the coordinated hydro system are shown for each of the 90 different river flow conditions using current system operating criteria in Figure 10. For perspective, the 50th percentile, 8th percentile and the added 10-years of water conditions are highlighted. The 8th percentile monthly energy difference is indistinguishable between the 80-year and 90-year historical river flows.

Figure 10. Monthly Hydro Generation Across 90-year historical record



Peak Capability

For this report the peak capability of the hydro system represents maximum sustained hourly generation available to meet peak demand during the period of heavy load. Hydro-project owners submit a sustained peak capability for each project.[2] The bulk of the peak data in this report come from BPA. BPA has updated its critical peak planning from 1936-37 to the 10th percentile from the most recent 30-year historical record for water conditions. This increased the Federal system winter hydropower peaking capability and slightly reduced summer peaking capability.

The peaking capability of the hydro system maximizes available energy and capacity associated with the monthly distribution of streamflow. The peaking capability is the hydro system's ability to continuously produce power for a specific time period by utilizing the limited water supply while meeting power and non-power requirements, scheduled maintenance, and operating reserves.

Columbia River Treaty

Since 1961 the United States has had a treaty with Canada that outlines the operation of U.S. and Canadian storage projects to increase the total combined generation. Hydropower generation in this analysis reflects the firm power generated by coordinating operation of three Canadian reservoirs, Duncan, Arrow and Mica with the Libby reservoirs and other power facilities in the region. Canada's share of the coordinated operation benefits is called Canadian Entitlement. BPA and each of the non-Federal mid-Columbia project owners are obligated to return their share of the downstream power benefits owed to Canada. The delivery of the Entitlement is reflected in this analysis and makes up the bulk of the region's exports in this year's report.

Downstream Fish Migration

Another requirement incorporated in the hydro modeling are modified river operations to provide for the downstream migration of anadromous fish. These modifications include adhering to specific flow limits at some projects, spilling water at several projects, and augmenting flows in the spring and summer on the Columbia, Snake and Kootenai rivers. Specific requirements are defined by various federal, regional and state mandates, such as project licenses, biological opinions and state regulations.

Thermal and Renewable Resources

Thermal resources are reported in a variety of categories including coal, natural gas, nuclear and other. Other includes cogeneration, diesel and oil.

Renewable resources other than hydropower are categorized as solar, wind and other renewables and are each totaled and reported separately. Other renewables include energy from biomass, geothermal, municipal solid waste projects, and other projects.

[2] Historically, a 50-hour sustained peak (10 hours/day for 5 days) was reported. Project owners/sponsors use a variety of peak capability metrics today.

All existing generating plants, regardless of size, are included in amounts submitted by each utility that owns or is purchasing the generation. The energy and peaking capabilities of plants are submitted by the projects' owners and take into consideration scheduled maintenance (including refueling), forced outages, and other expected operating constraints. Some small thermal plants and combustion turbines are included as peaking resources and their reported energy capabilities are only the amounts necessary for peaking operations. Additional energy may be available from these peaking resources but is not included in the regional energy load/resource balance.

Battery Storage

In recent years battery storage resources have made their way into the region's resource mix, with a relatively large amount planned in the next 10 years (albeit with a relatively small amount online/firmly committed as of this year's report). Battery storage is showing up as a standalone resource and in combination with solar and wind generation. It is reflected as supply during the peak hour of the month. Due to the small magnitude online/firmly committed at this time the capability is tallied within the Small Thermal and Miscellaneous resources category – this will change as more come online.

New and Future Resources

The latest activity with new and future resource developments, including expected savings from demand-side management actions, are tabulated in this report. These resources are reported as recently acquired, committed new supply, and planned future resources to reflect the different stages of development.

Recently Acquired Resources

The Recently Acquired Resources reported in *Table 5* have been acquired in the past year and are serving Northwest utility loads as of December 31, 2022. They are reflected as part of the regional firm needs assessment.

Committed New Supply

Committed New Supply reported in *Table 6* includes projects under construction or firmly committed to meet Northwest load that are not delivering power as of December 31, 2022. These resources are included in the regional load-resource analysis. Future energy efficiency and demand response programs are included in the load-resource analysis as well (see *Table 7*).

Planned Future Resources

Planned Future Resources presented in *Table 8* includes specific resources and/or blocks of generic resources identified in utilities' most current integrated resource plans or planning studies. Projects in *Planned Future Resources* are not yet under construction, are not part of the regional analysis, and are subject to change until the time for acquiring them is closer. As the resource build date nears, more

information about these resources will likely become available, and they typically move into the *Committed New Supply* category prior to coming online. Often, the utility will undergo a request for proposal process before moving a resource from *Planned* to *Committed.* Resources in this category are *referred to as Potential Resources* in some previous *Northwest Regional Forecasts*.

Contracts

Imports and exports include firm arrangements for trade with systems outside the region, as well as with third-party developers/owners within the region. These arrangements comprise firm contracts with utilities to the East, the California and Canada. Contracts to and from these areas are amounts delivered at the area border and include transmission losses associated with deliveries.

Long-term intraregional contracts between Northwest utilities net to zero in the regional picture and consequently are not tallied for this report. In addition, short-term and/or spot purchases from Northwest independent power producers and from out-of-region are not reflected in the tables that present the firm load resource comparisons in this report.

Non-Firm Resources

The *Northwest Regional Forecast* omits from the load/resource balance non-firm power supply that may be available to utilities to meet needs. These non-firm sources include generation from uncommitted Northwest independent power producers (IPPs), imports from power plants located outside the region, uncommitted hydro generation owned by Northwest utilities, and hydro generation likely available when water supply is greater than the assumed critical levels.

Independent Owned Generating Resources, presented in *Table 11*, details IPPs located in the region. Power from these resources may be available to the Northwest from the market, during high need hours, or it may have been already sold to a higher bidder outside the Northwest.

Non-firm imports depend on several factors including availability of out-of-region resources, availability of transmission, and market friction. The trend of large thermal resource retirements in the Western Interconnection could impact power available for import into the Northwest in the coming years. Looking at hydropower, the *Forecast* assumes low water (8%) during peak hours for the monthly peak calculations. Most months the water supply for the hydro system is not at critical levels. During a median water month, the region will have more water available for energy and peak needs.

Climate Change

More utilities and organizations are incorporating the impacts of a changing climate into their long-range planning. Two areas where climate change may impact utility planning is the influence of temperatures on loads and water supply for hydrogeneration. As more utilities account for changing temperature trends in their forecasting models the impact on utility loads becomes incorporated into the *Northwest Regional*

Forecast. Increasing temperatures in the summer can result in higher summer load (due to air conditioning, for example) and moderately warmer temperatures in the winter can reduce winter load (reduced need for heating loads), on average across the region. The differences in geography for utilities across the Northwest means individual utilities can have varying degrees of climate change effects.

The *2023 Forecast* does not explicitly include the impact of climate change on hydroelectric generation. It is only included to the extent that it is included in a hydro-project owner/sponsor's submittal of its peak capability for the project. The report's hydroelectric data for the bulk of the hydro data rely on the historical river flows.

Table 12. Utilities Included in the Northwest Regional Forecast

Albion, City of
Alder Mutual
Ashland, City of
Asotin County PUD #1
Avista Corp.
Bandon, City of
Benton PUD
Benton REA
Big Bend Electric Co-op
Blachly-Lane Electric Cooperative
Blaine, City of
Bonners Ferry, City of
Bonneville Power Administration
Burley, City of
Canby Utility
Cascade Locks, City of
Central Electric
Central Lincoln PUD
Centralia, City of
Chelan County PUD
Cheney, City of
Chewelah, City of
City of Port Angeles
Clallam County PUD #1
Clark Public Utilities
Clatskanie PUD
Clearwater Power Company
Columbia Basin Elec. Co-op
Columbia Power Co-op
Columbia REA
Columbia River PUD
Consolidated Irrigation Dist. #19
Consumers Power Inc.
Coos-Curry Electric Cooperative
Coulee Dam, City of
Cowlitz County PUD
Declo, City of
Douglas County PUD
Douglas Electric Cooperative
Drain, City of
East End Mutual Electric
Eatonville, City of
Ellensburg, City of
Elmhurst Mutual P & L
Emerald PUD
Energy Northwest
Eugene Water & Electric Board
Fall River Rural Electric Cooperative
Farmers Electric Co-op
Ferry County PUD #1
Fircrest, Town of
Flathead Electric Cooperative
Forest Grove Light & Power
Franklin County PUD
Glacier Electric
Grant County PUD
Grays Harbor PUD
Harney Electric
Hermiston, City of
Heyburn, City of
Hood River Electric
Idaho County L & P
Idaho Falls Power
Idaho Power
Inland Power & Light
Kittitas County PUD
Klickitat County PUD
Kootenai Electric Co-op
Lakeview L & P (WA)
Lane Electric Cooperative
Lewis County PUD
Lincoln Electric Cooperative
Lost River Electric Cooperative
Lower Valley Energy
Mason County PUD #1
Mason County PUD #3
McCleary, City of
McMinnville Water & Light
Midstate Electric Co-op
Milton, Town of
Milton-Freewater, City of
Minidoka, City of
Missoula Electric Co-op
Modern Electric Co-op
Monmouth, City of
Nespelem Valley Elec. Co-op
Northern Lights Inc.
Northern Wasco Co. PUD
NorthWestern Energy
Ohop Mutual Light Company
Okanogan Co. Electric Cooperative
Okanogan County PUD #1
Orcas Power & Light
Oregon Trail Co-op
Pacific County PUD #2
PacifiCorp
Parkland Light & Water
Pend Oreille County PUD
Peninsula Light Company
Plummer, City of
PNGC Power
Port of Seattle – SEATAC
Portland General Electric
Puget Sound Energy
Raft River Rural Electric
Ravalli Co. Electric Co-op
Richland, City of
Riverside Electric Co-op
Rupert, City of
Salem Electric Co-op
Salmon River Electric Cooperative
Seattle City Light
Skamania County PUD
Snohomish County PUD
Soda Springs, City of
Southside Electric Lines
Springfield Utility Board
Steilacoom, Town of
Sumas, City of
Surprise Valley Elec. Co-op
Tacoma Power
Tanner Electric Co-op
Tillamook PUD
Troy, City of
Umatilla Electric Cooperative
Umpqua Indian Utility Co-op
United Electric Cooperative
US Corps of Engineers
US Bureau of Reclamation
Vera Water & Power
Vigilante Electric Co-op
Wahkiakum County PUD #1
Wasco Electric Co-op
Weiser, City of
Wells Rural Electric Co.
West Oregon Electric Cooperative
Whatcom County PUD
Yakama Power

Definitions

Annual Energy

Energy value in megawatts that represents the average output over the period of one year. Expressed in average megawatts.

Average Megawatts

(aMW) Unit of energy for either load or generation that is the ratio of energy (in megawatt-hours) expected to be consumed or generated during a period of time to the number of hours in the period.

Batteries

Batteries are some of the newest technologies being added to the regional picture. They are reported as part of the Small Thermal and Miscellaneous resources at this time. See storage definition.

Biomass

Any organic matter which is available on a renewable basis, including forest residues, agricultural crops and waste, wood and wood wastes, animal wastes, livestock operation residue, aquatic plants, and municipal wastes.

Canadian Entitlement

Canada is entitled to one-half the downstream power benefits resulting from Canadian storage as defined by the Columbia River Treaty. Canadian entitlement returns estimated by Bonneville Power Administration.

Coal Resource

This category of generating resources includes the region's coal-fired plants.

Cogeneration

Cogeneration is the technology of producing electric energy and other forms of useful energy (thermal or mechanical) for industrial and commercial heating or cooling purposes through sequential use of an energy source.

Combustion Turbines

These are plants with combined-cycle or simple-cycle natural gas-fired combustion turbine technology for producing electricity.

Committed Resources

These projects are under construction and/or committed resources and supply confirmed to meet Northwest load, but not delivering power as of December 31, 2022.

Conservation

Any reduction in electrical power consumption as a result of increases in the efficiency of energy use, production, or distribution. For the purposes of this report used synonymously with energy efficiency.

Demand Response

Control of load through customer/utility agreements that result in a temporary change in consumers' use of electricity.

Demand-side Management

Peak and energy savings from conservation/energy efficiency measures, distribution efficiency, market transformation, demand response, fuel conversion, fuel switching, energy storage and other efforts that that serve to reduce electricity demand.

Dispatchable Resource

A term referring to controllable generating resources that are able to be dispatched for a specific time and need.

Direct Service Industries (DSI)

Large electricity-intensive industries such as aluminum smelters and metals-reduction plants that purchase power directly from the Bonneville Power Administration for their own use. Very few of these customers exist in the region today.

Distribution Efficiency

Infrastructure upgrades to utilities' transmission and distribution systems that save energy by minimizing losses.

Emerging Technologies

A term used to describe future resource technologies such as advanced nuclear, offshore wind, renewable hydrogen, and long-duration storage.

Encroachment

A term used to describe a situation where the operation of a hydroelectric project causes an increase in the level of the tailwater of the project that is directly upstream.

Energy Efficiency

Any reduction in electrical power consumption as a result of increases in the efficiency of energy use, production, or distribution. For the purposes of this report used synonymously with conservation.

Energy Load

The demand for power averaged over a specified period of time.

Energy Storage

Technologies for storing energy in a form that is convenient for use at a later time when a specific energy demand is greater.

Exports

Firm interchange arrangements where power flows from regional utilities to utilities outside the region or to non-specific, third-party purchasers within the region.

Federal System (BPA)

The federal system is a combination of BPA's customer loads and contractual obligations, and resources from which BPA acquires the power it sells. The resources include plants operated by the U.S. Army Corps of Engineers (COE), U.S. Bureau of Reclamation (USBR) and Energy Northwest. BPA markets the thermal generation from Columbia Generating Station, operated by Energy Northwest.

Federal Columbia River Power System (FCRPS)

Thirty federal hydroelectric projects constructed and operated by the Corps of Engineers and the Bureau of Reclamation, and the Bonneville Power Administration transmission facilities.

Firm Energy

Electric energy intended to have assured availability to customers over a defined period.

Firm Load

The sum of the estimated firm loads of private utility and public agency systems, federal agencies and BPA industrial customers.

Firm Losses

Losses incurred on the transmission system of the Northwest region.

Fuel Conversion

Consumers' efforts to make a permanent change from electricity to natural-gas or other fuel source to meet a specific energy need, such as heating.

Fuel Switching

Consumers' efforts to make a temporary change from electricity to another fuel source to meet a specific energy need.

Historical Streamflow Record

A database of unregulated streamflows for 90 years (August 1928 to July 2018). Data is modified to take into account adjustments due to irrigation depletions, evaporations, etc. for the particular operating year being studied.

Hydro Maintenance

The amount of energy lost due to the estimated maintenance required during the critical period. Peak hydro maintenance is included in the peak planning margin calculations.

Hydro Regulation

A study that utilizes a computer model to simulate the operation of the Pacific Northwest hydroelectric power system using the historical streamflows, monthly loads, thermal and other non-hydro resources, and other hydroelectric plant data for each project.

Imports

Firm interchange arrangements where power flows to regional utilities from utilities outside the region or third-party developer/owners of generation within the region.

Independent Power Producers (IPPs)

Non-utility entities owning generation that may be contracted (fully or partially) to meet regional load.

Intermittent Resource (a.k.a. Variable Energy Resource)

An electric generating source with output controlled by the natural variability of the energy resource rather than dispatched based on system requirements. Intermittent output usually results from the direct, non-stored conversion of naturally occurring energy fluxes such as solar and wind energy.

Investor-Owned Utility (IOU)

A privately owned utility organized under state law as a corporation to provide electric power service and earn a profit for its stockholders.

Market Transformation

A strategic process of intervening in a market to accelerate the adoption of cost-effective energy efficiency.

Megawatt (MW)

A unit of electrical power equal to 1 million watts or 1,000 kilowatts.

Nameplate Capacity

A measure of the approximate generating capability of a project or unit as designated by the manufacturer.

Natural Gas-Fired Resources

This category of resources includes the region's natural gas-fired plants, mostly single-cycle and combined-cycle combustion turbines. It may include projects that are considered cogeneration plants.

Non-Firm Resources

Electric energy acquired through short term purchases of resources not committed as firm resources. This includes generation from hydropower in better than critical water conditions, independent power producers and imports from outside the region.

Non-Utility Generation

Facilities that generate power whose ownership by a sponsoring utility is 50 percent or less. These include PURPA-qualified facilities (QFs) and non-qualified facilities of independent power producers.

Nuclear Resources

The region's only nuclear plant, the Columbia Generating Station, is included in this category.

Operating Year

Twelve-month period beginning on August 1 of any year and ending on July 31 of the following year. For example, operating year 2017 is August 1, 2016 through July 31, 2017.

Other Publics (BPA)

Refers to the smaller, non-generating public utility customers whose load requirements are estimated and served by Bonneville Power Administration as referred to in Table 10.

Peak Load

In this report the peak load is defined as one-hour maximum demand for power.

Planned Future Resources

These resources include specific resources and/or blocks of generic resources identified in utilities' most current integrated resource plans. These projects are not yet under construction, are not part of the regional analysis, and are in some ways speculative.

Planning Margin

A component of regional requirements that is included in the peak needs assessment to account for various planning uncertainties. In the 2018 *Forecast* the planning margin changed to a flat 16% of the regional load for each year of the study. Earlier reports included a growing planning margin that started at 12% of load, increasing 1% per year until it reached 20%.

Private Utilities

Same as investor-owned utilities.

Publicly-Owned Utilities

One of several types of not-for-profit utilities created by a group of voters and can be a municipal utility, a public utility district, or an electric cooperative.

PURPA

Public Utility Regulatory Policies Act of 1978. The first federal legislation requiring utilities to buy power from qualifying independent power producers.

Renewables - Other

A category of resources that includes projects that produce power from such fuel sources as geothermal, biomass (includes wood, municipal solid-waste facilities), and pilot level projects including tidal and wave energy.

Requirements

Include for each year, a utility's projected loads, exports, and contracts out. Peak requirements also include the planning margin.

Small Thermal & Miscellaneous Resources

This category of resources includes small thermal generating resources such as diesel generators used to meet peak and/or emergency loads.

Solar Resources

Resources that produce power from solar exposure. This includes utility scale solar photovoltaic systems but does not include distributed solar generation.

Storage

Storage resources (i.e., batteries, pumped hydro, liquid air) store energy for release at a later time. They can help shift energy from low value to high value hours. Due to efficiency losses, they are a net consumer of energy. They are usually defined by their maximum discharge rate in MW, and their total storage capacity in MWh.

Thermal Resources

Resources that burn coal, natural gas, oil, diesel or use nuclear fission to create heat which is converted into electricity.

Variable Energy Resource (a.k.a. Intermittent Resource)

An electric generating source with output controlled by the natural variability of the energy resource rather than dispatched based on system requirements. Intermittent output usually results from the direct, non-stored conversion of naturally occurring energy fluxes such as solar and wind energy.

Wind Resources

This category of resources includes the region's utility-scale wind powered projects.

Western Energy Imbalance Market (WEIM)

A real-time energy market launched in 2014, operated by the California Independent System Operator.

Western Resource Adequacy Program (WRAP)

A regional reliability and compliance program in the West. It delivers a region-wide approach for assessing and addressing resource adequacy.

Attachment 14. WECC Email Granting Phase 3 Status

From: Ernie Griggs
To: Ed Stern; Jeff Wood; Corey Kupersmith; Chris Hocker; Susan Brown; Carol Loughlin; Chris Benson; John Ostrowski; victor@sun2o.com
Subject: FW: Phase 3 Notification - Cascade Renewable Transmission Project HVDC Transmission Line Project - Granted Phase 3 Status
Date: Monday, June 27, 2022 8:38:08 PM
Attachments: F005C8B1EDCE499C81AEB0BB4F1416F3.png

From: Tucker, Doug <dtucker@wecc.org>
Sent: Monday, June 27, 2022 12:15 PM
Cc: Ellis, Jeff <jeffellis@useconsulting.com>; Ernie Griggs <egriggs@powerbridge.us>
Subject: Phase 3 Notification - Cascade Renewable Transmission Project HVDC Transmission Line Project - Granted Phase 3 Status

Phase 3 Notification - Cascade Renewable Transmission Project HVDC Transmission Line Project – Granted Phase 3 Status

Reliability Assessment Committee

Reliability Risk Committee

Studies Subcommittee

The following is a WECC Project Coordination, Path Rating and Progress Report Processes notice.

This e-mail is to inform you that the Cascade Renewable Transmission System HVDC Transmission Project, an 1,100 MW HVDC transmission line project has completed the steps necessary to enter Phase 3 of the Path Rating Process. Cascade Renewable Transmission, LLC did receive one comments during the 30 day review period and this has been addressed. Therefore, in accordance with the WECC Project Coordination, Path Rating and Progress Report Process, Cascades Renewable Transmission System HVDC Transmission Project is hereby granted Phase 3 status, with an Accepted Rating of 1,100 MW. All projects identified in the study report are scheduled to be in service by December, 2027.

The table below shows how the project has progressed through the process.

Phase	Requested Phase/Report Posted for Comments	Granted Phase
Phase 1	September 4, 2020	September 4, 2020
Phase 2a	April 19, 2021	June 18, 2021
Phase 2b	Not Applicable	November 13, 2021
Phase 3	May 12, 2022	June 27, 2022

If you have any comments/questions please send them to Jeff Ellis (JeffEllis@USEConsulting.com) or Ernest Griggs (egriggs@powerbridge.us) and Doug Tucker (dtucker@wecc.org) from WECC staff.

Thanks,

Chifong Thomas
RAC Chair

Attachment 15. Energy GPS Production Cost Analysis Report

November 2025

Cascade Renewable Transmission Project Analysis

Prepared for

Cascade Renewable Transmission, LLC

Prepared by

Energy GPS Consulting (EGPSC), LLC

11/18/2022

ENERGYGPS CONSULTING LLC

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Executive Summary

Cascade Renewable Transmission, LLC (CRT) proposes to develop and construct a 1,100 MW underground and underwater transmission line between The Dalles and Portland, OR (Project) for the purpose of enhancing transmission transfer capability of the West of Cascades – South (WOCS) Transmission Path[1]. The Project is scheduled to become operational in 2028. This study, conducted by Energy GPS Consulting LLC, analyzes the costs and benefits of the Project, taking into account legislation in Washington and Oregon requiring 100% clean energy retail sales by 2045 in Washington, and 100% clean energy generation by 2040 in Oregon.

Under current conditions, the WOCS transmission constraint limits the transfer of least-cost renewable energy to load centers west of the Cascades. Moreover, this constraint may require more expensive resources to be sited west of the Cascades. Therefore, upgrades to the existing transmission constraint may reduce overall system production costs.

The study envisions two scenarios: 1) "Business As Usual" load growth projections in Washington and Oregon between 2022 and 2040 representing annual growth rates in energy and peak demand of 0.6% and 0.9%, respectively; and 2) partial electrification of the transportation and heating sectors representing annual growth rates in energy and peak demand of 3.0% and 1.8%, respectively.

For Scenario 1 (Business As Usual), the study shows that without the CRT Project, clean energy capacity additions of 52.9 GW for Washington and Oregon would be needed by 2040, whereas the reductions in transmission constraint resulting from the CRT Project would lower this need to 43.5 GW, or a reduction of 9.4 GW, nearly 18%. This reduction in aggregate GW of new build renewables would also significantly decrease the amount of land needed for solar and wind farms. Moreover, alleviating the WOCS constraint reduces the need to build more expensive west-of-Cascades capacity, and significantly reduces the need for curtailments of renewable generation. (In other words, renewable generation becomes both less expensive and more efficient.) The resulting Production Cost Savings between 2028 and 2040 are estimated to have a Net Present Value (NPV) of $4.1 billion.

For Scenario 2 (Electrification), the need for clean energy capacity additions by 2040 increases to 138 GW without the CRT Project, while the Project would reduce this need by 14.7 GW (10.7%). As in Scenario 1, the Project reduces the need for more expensive western renewable generation while also reducing curtailments, with an estimated resulting Production Cost Savings NPV of $5 billion between 2028 and 2040.

For both Scenarios 1 and 2, extrapolating growth rates beyond 2040 for the duration of the useful life of the Project significantly increases the NPV in Production Cost Savings attributable to the CRT Project.

[1] The WOCS Transmission Path, or Path 5, is a major east-west high voltage transmission intertie path from east of the Cascades into the Portland area within the Western Electricity Coordinating Council (WECC), currently with a maximum transfer limit of 7,600 MW in the winter and 5,930 MW in the summer.

Background

Energy GPS Consulting (EGPSC) was retained by Cascade Renewable Transmission, LLC (CRT) to conduct a cost-benefit analysis of enhancing the transmission transfer capability of the West of Cascades - South (WOCS) Transmission Path. The WOCS transmission constraint exists between the west of Cascades load areas (e.g., Portland) and the east generating resources (e.g., generators in eastern Oregon and Washington). CRT has proposed the Cascade Renewable Transmission Project (CRT Project, or Project), an underground and underwater High Voltage Direct Current (HVDC) transmission line between The Dalles and Portland, OR that would add 1,100 MW of east-to-west transfer capability. The Project is currently in development with a target in-service date of 2028.

The WOCS transmission constraint may play a major role in determining the location of new generating capacity required to meet clean energy laws in Washington and Oregon. That is, there is a significant amount of capacity required to meet the clean energy laws and the least cost location for this new capacity is east of the Cascades in Washington, Oregon, Idaho, Montana, and Wyoming. However, the current transfer capability to enable east-of-the-Cascades capacity to serve west-of-the-Cascades load may limit the feasibility of adding the least cost capacity. Moreover, the absence of increased transfer capability from the east to the west may require more expensive west-sited resources such as commercial and industrial (C&I) solar. Therefore, upgrades to the transmission constraint may allow for lower cost eastern generation to serve western load and thereby reduce overall system production costs.

Goals and Scenarios

The overarching goal of this analysis is to demonstrate the benefits in Oregon and Washington, if any, of increasing the WOCS path capability in future years 2028 to 2040. (For the purposes of this study, we refer to the Pacific Northwest (PNW) power grid which includes the Balancing Authorities that cover Oregon, Washington, and Montana. The NWMT Balancing Authority was included to capture the likelihood of significant wind generation resources in Montana that could be available to west-of-Cascades load). The chosen study years were selected to coincide with the anticipated initial first few operating years of the Project and a reasonable projection of future years that reflect progress towards Washington's CETA law[2] of 100% clean energy retail sales by 2045 and Oregon House Bill 2021[3] requiring 100% clean energy by 2040. There are many uncertainties with meeting these clean energy laws and maintaining reliability. Focusing the analysis on years before both laws require 100% clean energy helps address the uncertainty of the ability to meet the laws by target dates.

In addition, two scenarios were chosen to quantify uncertainty in load growth: 1) benefits of the Project under business-as-usual (BAU) load growth (i.e., current P50 load growth representing a 0.6% and 0.9% annual growth rate in energy and peak demand, respectively, in Washington and Oregon from 2022 to 2040), and 2) benefits of the Project under a high load growth projection that represents partial electrification of the transportation and heating sectors (representing a 3.0% and 1.8% annual growth

[2]WA CETA; https://www.commerce.wa.gov/growing-the-economy/energy/ceta/

[3] OR HB 2021; https://www.oregon.gov/puc/Documents/HB2021-Summary.pdf

rate in energy and peak demand, respectively, in Washington and Oregon from 2022 to 2040, equaling a 40% increase in energy and 14% increase in peak demand by 2040 as compared to the P50 case). These were selected because there is great concern that the conversion of heating units to electricity, addition of air conditioning units in the PNW, and plans of electric vehicles replacing gas vehicles will cause significant increases in load growth over the next several decades.

Approach

To quantify the benefits of the Project under each scenario we ran a zonal production cost model of the geographic area covered by the Western Electricity Coordinating Council (WECC) from 2022 to 2040. The model was used to estimate two capacity expansion plans, one with and one without the Project's increased transmission capability for each scenario (four expansion plans in total). Since the model has perfect foresight, with the CRT line assumed to be operational January 1, 2028, we established the 2027 results of the case without CRT as the starting point from which to optimize the CRT case. The model was analyzed for future years 2028 to 2040 in terms of ability to meet reliability and policy goals of Washington and Oregon. Outputs include hourly generation at each zone and transmission flows on major paths. Differences between runs in terms of the capacity expansion plans and associated total system production costs were used to demonstrate benefits of the Project. Detailed information on the methods, models, and inputs for these simulations are described in Appendix A.

The model simulations are summarized below.

Table 1. Summary of each production cost model simulation as proposed. LTCE = Long-term capacity expansion.

Scenario	Name	Type	Notes
1	Case 1 – Base	LTCE and Dispatch	Most likely outcome w/o Project
1	Study Case 1 – CRT	LTCE and Dispatch	Most likely outcome w/ Project
2	Case 2 – Base	LTCE and Dispatch	High load growth scenario w/o Project
2	Study Case 2 – CRT	LTCE and Dispatch	High load growth scenario w/ Project

Results and Discussion

Scenario 1: P50 Load Growth

Significant clean energy capacity additions are required to meet reliability standards and clean energy laws in Washington and Oregon. Using Aurora to simulate the PNW system as defined here, we estimate that by 2040 capacity additions for Washington and Oregon are 52.9 GW without the CRT transmission line (see Figure 1). In addition to meeting clean energy laws, these capacity additions are also required to meet reliability standards assuming a projected peak load growth and planning reserve margin. These large amounts of capacity additions are driven by declining peak capacity contributions of renewable energy (as you add more and more capacity while pushing the net peak load hour back) and significant energy curtailment due to load and generation mismatch and transmission constraints.

As also shown on Figure 1, under Scenario 1 – Study Case 1, with the CRT line, capacity additions across the PNW system are forecast to be reduced by 9.4 GW to 43.5 GW. The rationale for lower capacity requirements with the CRT line is explained in the following paragraphs.

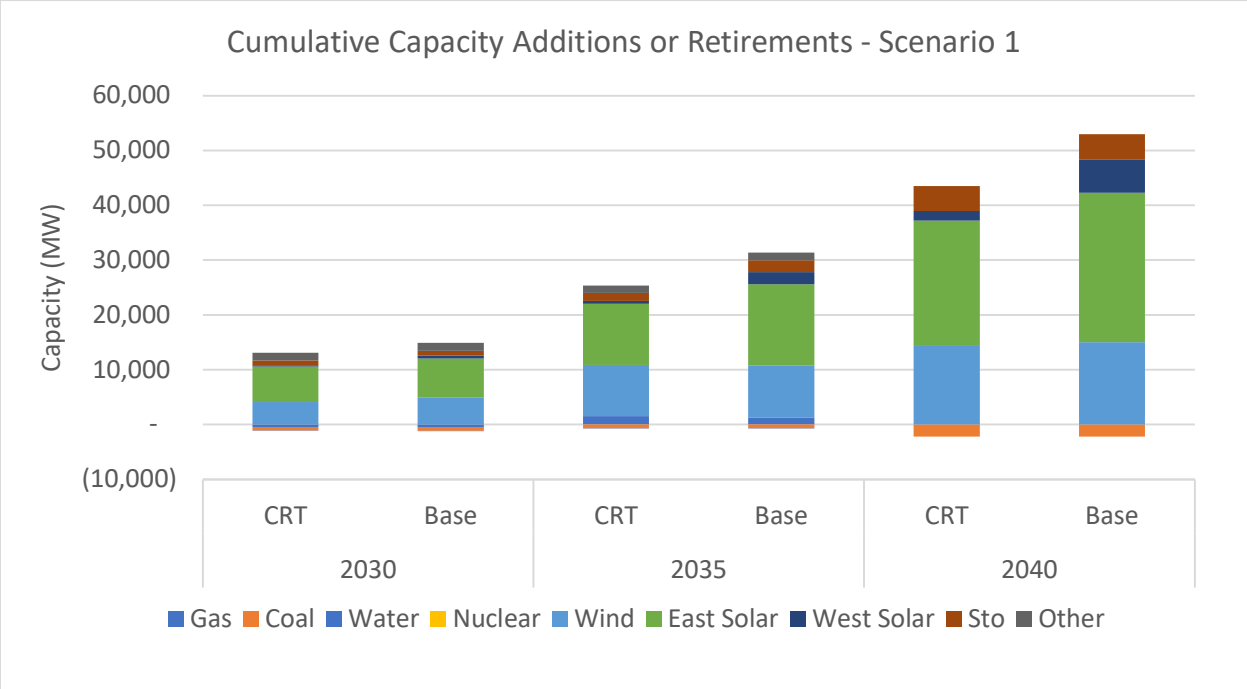

Figure 1. Capacity addition and retirement mix in Washington and Oregon for future years for Scenario 1 model runs with CRT transmission upgrade (CRT) and without CRT (base).

The CRT line reduces the WOCS transmission constraint across all study years. The projected percent at max (amount of time the transmission line is fully loaded) of the WOCS is reduced from 19% to 6% in 2028 and from 38% to 24% by 2040 (Figure 2). This reduction in transmission line constraints in turn reduces renewable curtailment, thereby requiring fewer clean energy resources to meet reliability standards and clean energy laws. In addition to the significant cost savings from being able to construct fewer clean energy resources, there is the additional benefit of preserving significant acres of land from being impacted by solar and wind farms.

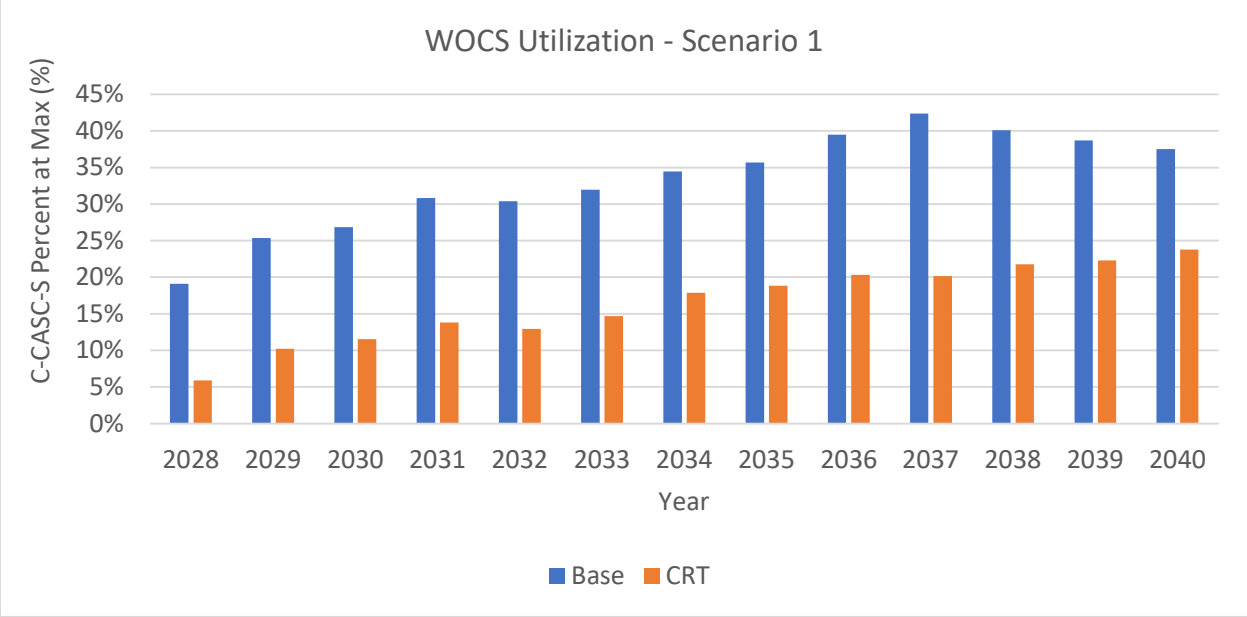

Figure 2. West of Cascades South (WOCS) line percent at max capacity with and without the CRT upgrade. Declining percent at max in the base case after 2037 is likely due to significant capacity additions west of the Cascades.

When adding such large amounts of renewable capacity, the curtailment rates can become significant. In the base case without CRT, the curtailment of renewable energy in the PNW is estimated to be 4,602 GWh, 25,141 GWh and 66,204 GWh by 2030, 2035, and 2040, respectively (Figure 3). With already low capacity factors from these variable energy resources, this significantly reduces the energy delivered to the grid by these resources. By adding additional transfer capability with the CRT Project, these estimated curtailments are reduced by 1,556 GWh, 7,272 GWh, and 16,558 GWh in 2030, 2035, and 2040, respectively. Lower curtailment means that fewer capacity additions are needed to meet clean energy laws and maintain reliability. Assuming a 30% capacity factor and 25% curtailment rate, this would equate to 8,400 MW fewer capacity additions resulting from lower curtailment alone.

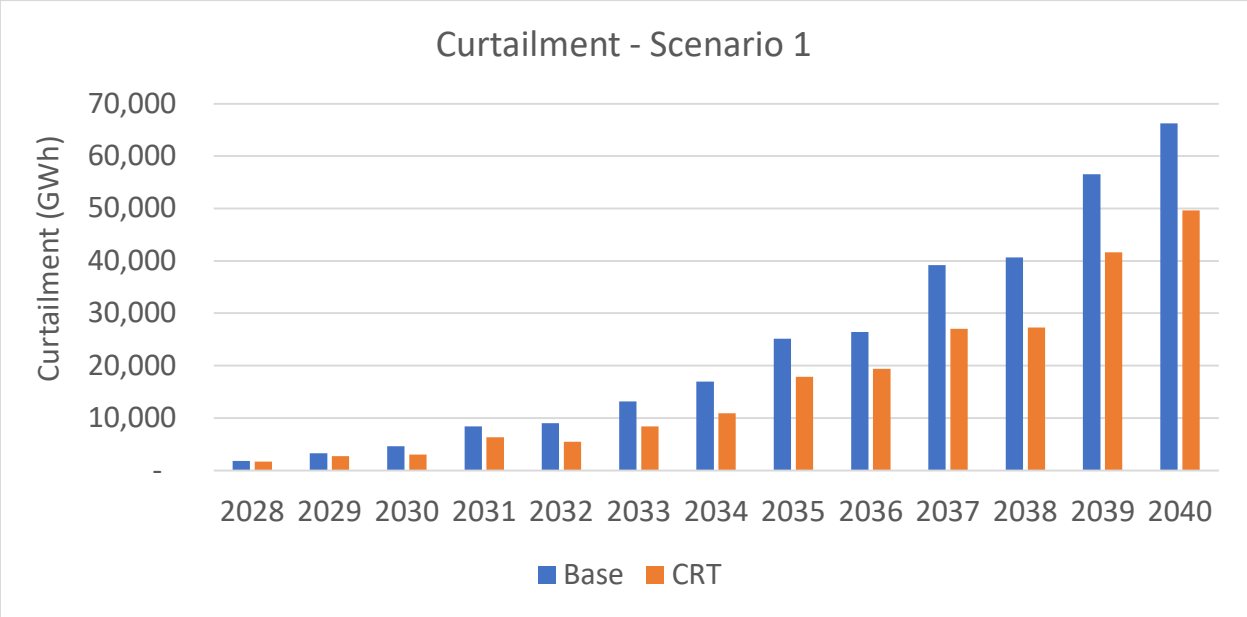

Figure 3. Renewable curtailment in the PNW for Scenario 1 model runs with CRT transmission upgrade (CRT) and without CRT (base).

Another benefit of the CRT Project relates to the location of the capacity additions. That is, increasing the WOCS transfer capability reduces the amount of capacity additions west of the Cascades. For Scenario 1, it is forecast that by 2040 4.2 GW less of solar is constructed west of the Cascades (Figure 4). This is an important cost reduction because this capacity would largely be higher cost C&I scale solar.

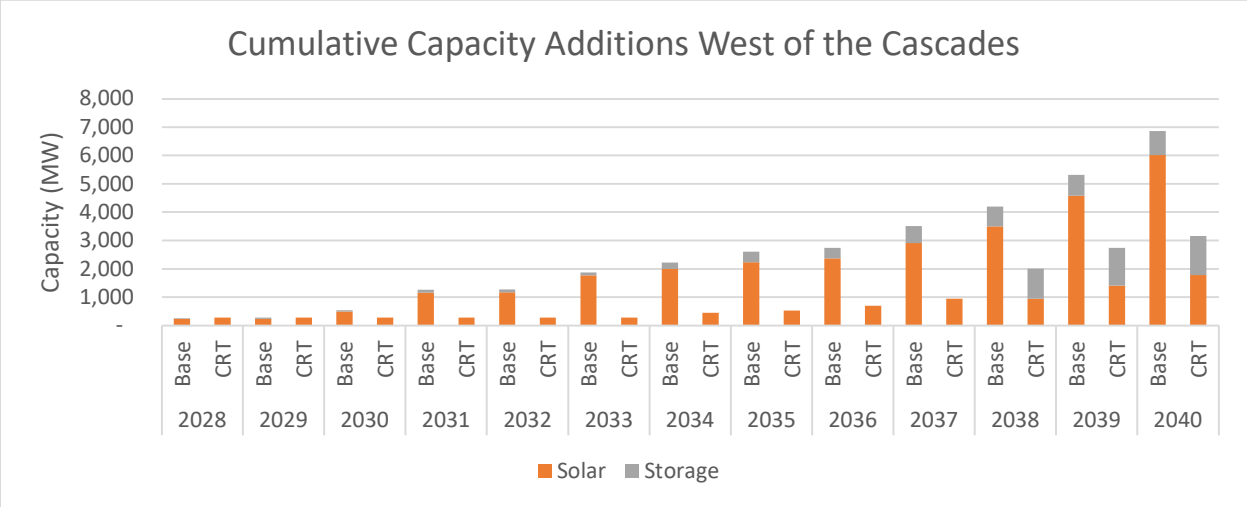

Figure 4. Capacity additions by type and location in the West of the Cascades.

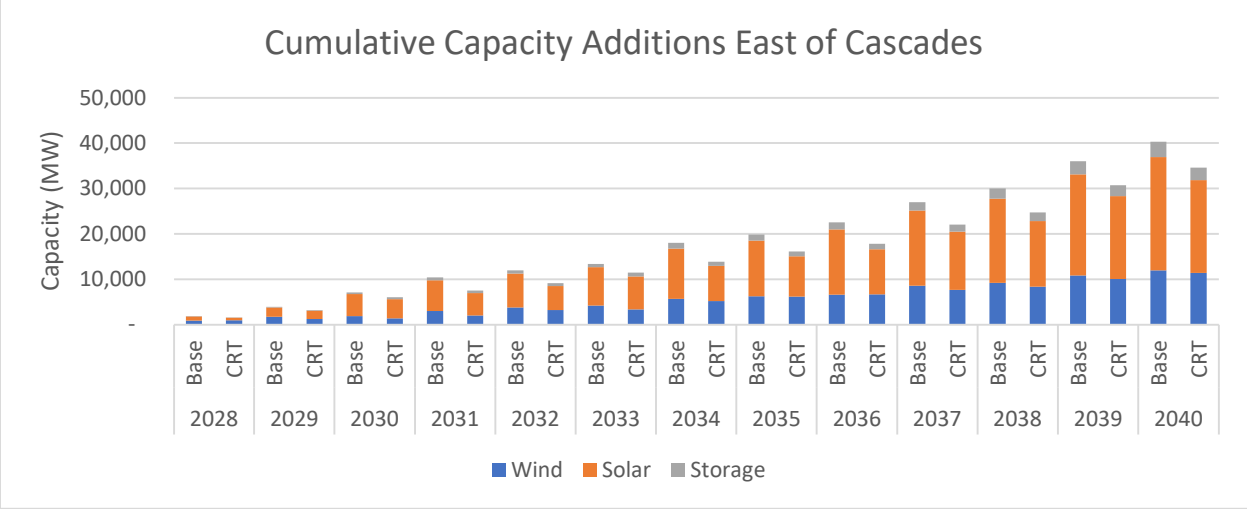

Figure 5. Capacity additions by type and location East of the Cascades.

By reducing the amount of required renewable capacity additions in total, as well as shifting away from higher-cost western resources, the CRT Project reduces total system production costs. The savings expressed as a net present value (NPV[4]) from 2028 to 2040 are $4.1 Billion (Figure 6). There are nearly $1B in cost savings in 2040, the last year of analysis. Thus, extrapolating these savings over an assumed 40-year project lifetime leads to an estimated NPV savings of $9.9 Billion from 2028 to 2067.

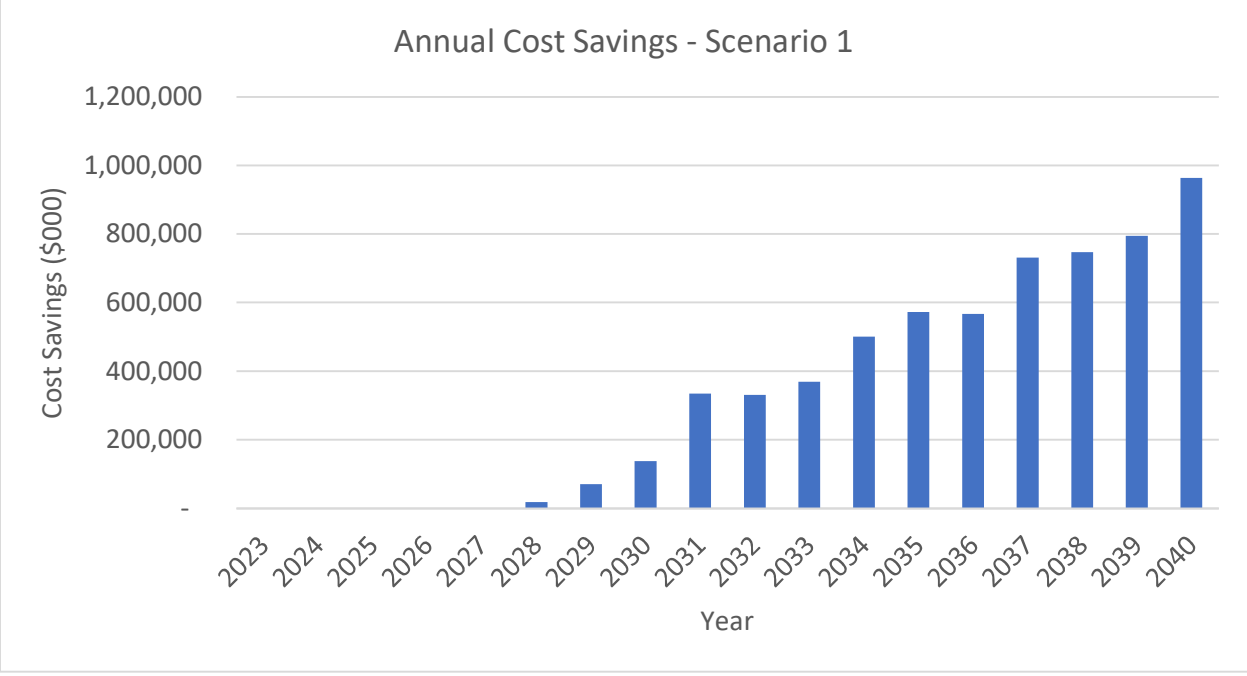

Figure 6. Annual system cost savings due to the CRT transmission addition.

[4] NPV calculation assumes an inflation rate of 2.5% annually and a 7% discount rate.

Scenario 2: Electrification

To develop new load forecasts to account for electrification, we estimated base load growths, electric vehicle load growth, and heating conversion load growth using the 2021 Washington State Energy Strategy[5]. Average annual load growth rates were increased to represent base load and heating load growth using the same hourly shape as Scenario 1. New hourly profiles[6] and load forecasts were also added to represent electric vehicle load growth. These changes were applied throughout the WECC for this scenario. The results were an increase from 0.6% to 3.0% annual average load growth rates and increase from 0.9% to 1.8% in annual average peak load growth rates in Washington and Oregon from 2022 to 2040. Stated differently, the electrification scenario adds 40% more energy and a 14% increase in peak load in 2040 as compared to the P50 business as usual load growth (Figure 7).

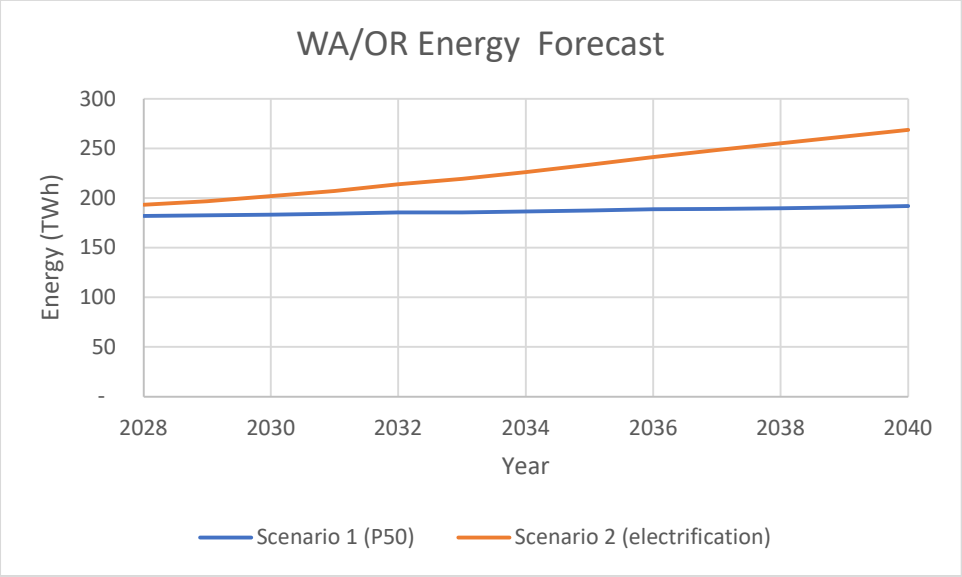

Figure 7. Load forecast in WA and OR under Scenario 1 and 2.

This additional load growth requires more renewable capacity additions in the PNW to meet clean energy laws and maintain system reliability as compared to Scenario 1: more than 138 GW in Scenario 2 by 2040 compared with 52.9 in Scenario 1. The CRT line is forecast to reduce the Scenario 2 amount by 14.7 GW. The reason for the reduction is the same as in Scenario 1, that is by reducing curtailment and allowing for more higher quality resources in the east-of-Cascades regions and fewer high-cost additions west of the Cascades. Under this scenario the CRT Project reduces total system production costs expressed as an NPV by $5 Billion for the period 2028 to 2040. There are nearly $1.6B in cost savings in 2040, the last year of analysis, resulting in an NPV reduction of total system production costs of $15 billion over an assumed 40-year life of the CRT project.

[5] https://www.commerce.wa.gov/growing-the-economy/energy/2021-state-energy-strategy/
[6] Derived from Mort and Mort (2019) https://www.iepec.org/wp-content/uploads/2019/02/abstracts_presentations_mort.pdf

Conclusions

This study demonstrates that significant levels of new clean energy capacity are required to meet the reliability standards and clean energy laws of Washington and Oregon by 2040. Beyond 2040 these requirements are expected to grow even larger. Because of the level of capacity required, the existing transmission constraints between the lower-cost and higher producing clean energy locations east of the Cascades and the load centers in the west become significantly more constrained. This transmission constraint, WOCS, leads to significant curtailment rates. Therefore, the combination of higher-cost west-side sited resources, such as C&I solar, and overbuilding of generation resources located east of the Cascades, becomes the least cost solution. However, if the transmission capability across the WOCS constraint is increased, less of the more expensive west of the Cascades resources are necessary and fewer high quality east renewable resources are needed to maintain system reliability and meet clean energy laws.

The economic benefits of the CRT line are driven by capital cost savings from reduced renewable resources and are estimated at $4.1 B in NPV (from 2028 to 2040) in Scenario 1 with current load forecasts and $5.0 B in NPV (from 2028 to 2040) in Scenario 2 with partial electrification of the transportation and heating sectors.

Table 2. Summary of CRT Economic Benefits.

Scenario	Capacity Reduction (GW)	NPV (2028 to 2040)	NPV (2028 to 2067)
#1 (P50)	9.4	$4.1 B	$9.9 B
#2 (Electrification)	14.7	$5.0 B	$15.0 B

An added benefit is minimizing land usage. Under Scenario 1, in 2040, with CRT, there is over 4,500 MW of solar and 560 MW of wind which no longer needs to be constructed east of the Cascades. Given average land usage for solar and wind farms, this equates to 25,000 – 32,000 acres of land which would not be impacted by the construction of new renewable generation.

Our assumptions did NOT include certain variables that might increase the benefits of the Project if they were included in this analysis:

- We assumed implementation of clean energy laws as RPS standards. We did not implement a strict definition of clean energy laws into the model, such as strict emission limits including tracking imports into Washington and Oregon. Enforcement of these laws in a stricter sense would lead to an increase in the capacity required to meet the laws and thus an increase in cost savings of the CRT project.
- We carried out our simulations only to 2040. Ending the simulation in 2040 did not simulate 100% clean energy laws for Washington, which set a 2045 deadline for achieving this goal.

Carrying out the simulation to 2045 would result in an increase in the amount of capacity required to meet clean energy laws and thus have an increase in cost savings of the CRT project.

Other considerations for future analyses:

- Demand response programs. Demand response was included in the model to avoid load shedding but was utilized for a very limited number of hours and only in the last few study years. Wide-scale demand response programs implemented earlier could change the capacity expansion plans and requirements to meet clean energy laws. The cost and magnitude of these programs vary widely. Future analyses of demand response programs may impact cost savings estimates depending on the design and cost of the demand response programs.
- Alternative technologies. Not-yet-established technologies in the WECC were not included such as hydrogen, small nuclear reactors, and offshore wind in the Pacific. Including these technologies may alter the capacity expansion plans and capacity additions and location to meet clean energy laws. Future analyses of alternative technologies may impact the cost savings.

Appendix A. Methods, Models, and Inputs

Production cost models ("PCM") are widely used to forecast future electrical system generating capacity mix to meet growing electricity demand and clean energy laws at the least cost solution. Inputs to PCM include the expected electricity demand forecast, the existing generators available to meet the load forecast, future candidate generators than can be added to meet growing load, physical constraints to either the generator operation or transmission line constraints, and policy constraints to meet laws. The inputs are formatted by the PCM to be read into an optimization engine that solves for the least cost solution to meet demand at each interval (e.g., hour). Outputs from the PCM include a new supply stack (retirements and additions from the optimization) and the performance of that supply stack for each forecast interval (e.g., generation, fuel consumption, emissions, fixed and variable costs, imports, exports). Reliability metrics such as curtailed demand (loss of load) or required demand response are also available.

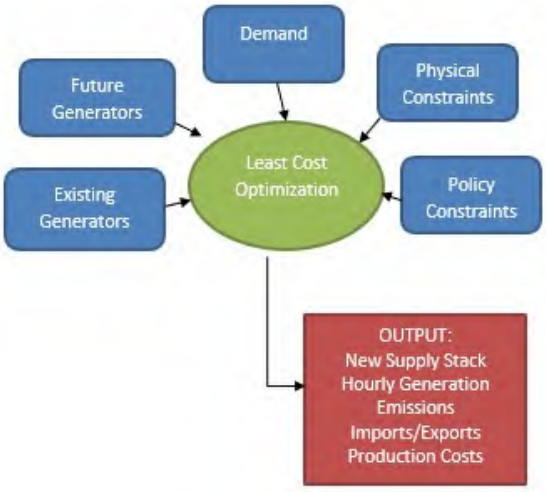

Figure 8.

We have been developing a PCM at EGPS for about a year now using a commercial PCM called Aurora. The inputs to our PCM have been derived from our internal power database as well as publicly available data. We have carefully calibrated the PCM to historical conditions from 2018 to 2021. Included in this is a unique hourly hydro generation calibration to historical hourly hydro generation data. Additional details and model inputs are described below.

The WECC is represented in our model by 40 zones including many of the 38 balancing authorities shown in Figure 9 with increased granularity for BPAT to separate the NW, SW, and Eastern zones of BPAT.

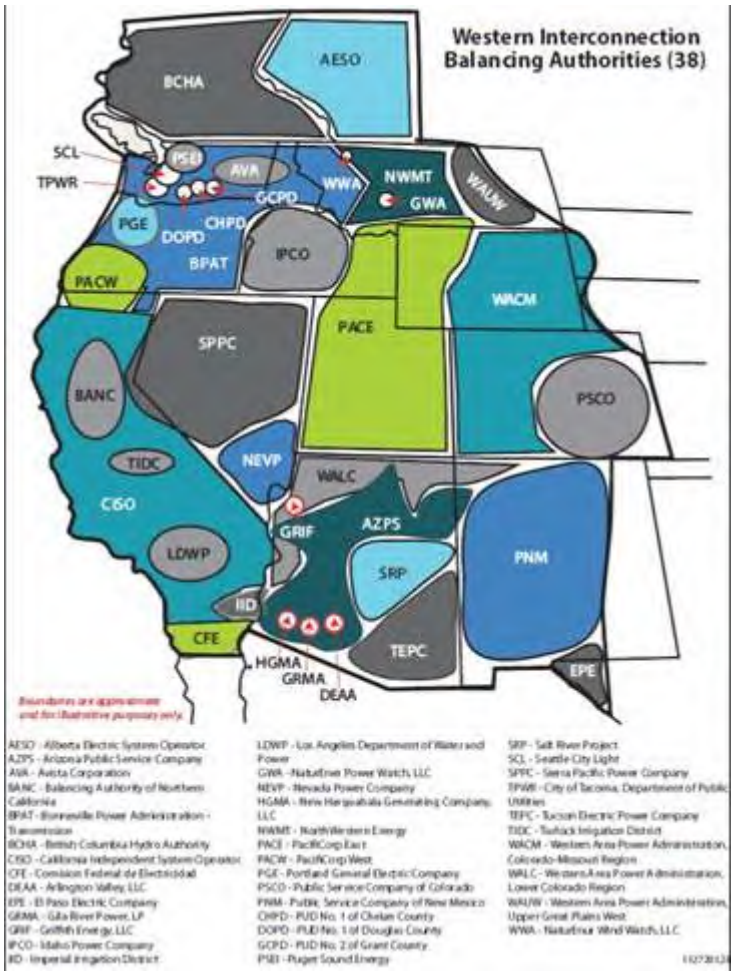

Figure 9. Balancing Authorities in the WECC.

This breakout allows us to capture the Cross Cascades and South of Allston transmission constraints. Transmission limits between zones are derived from historical flow limits, the CPUC RA and IRP Model7, and the WECC Power Supply Assessment8. A summary of the transmission assumptions in the PNW is shown below. Important considerations are that the cross cascades transmission limit is captured in our model through both the north and south constraint. In addition, there is some PacifiCorp load on the east side of the SWOCS constraint that is not split out in FERC 714 filings. To capture this, we applied a portion of the PACW load (500 MWa) to the BPAT_E zone.

[7] CPUC RA and IRP Model, https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2019-20-irp-events-and-materials/unified-ra-and-irp-modeling-datasets-2019

[8] WECC Power Supply Assessment, https://www.wecc.org/Reliability/2016PSA_Final.pdf

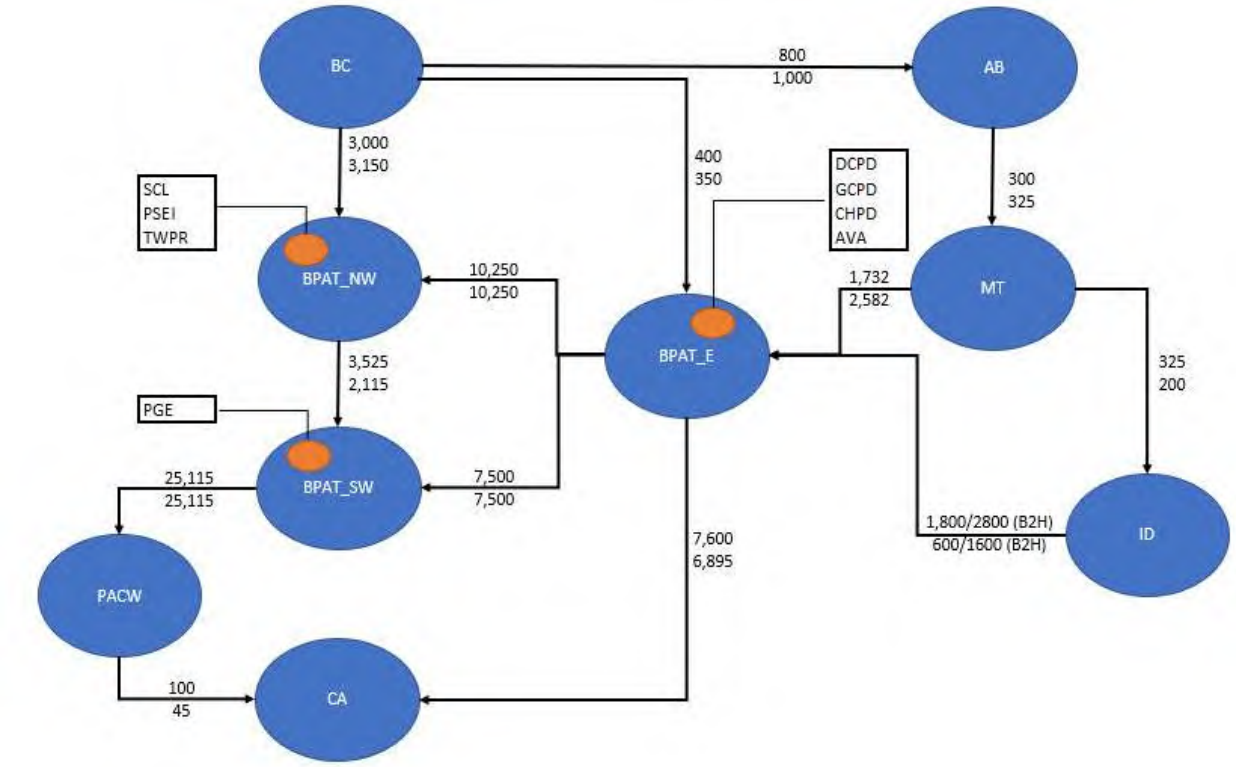

Figure 10. PNW transmission topology used in the PCM. Notes: 1) transmission outside of the PNW not shown here but the model does represent the entire WECC footprint. 2) a portion of PACW load is located in BPAT_E load zone.

Load forecasts for each zone are derived from the FERC 714 for zones in the U.S, the NERC ES&D for zones in Canada, and the PRODESEN for Mexico Baja California. Hourly load shapes are derived from the WECC Anchor Data Set (ADS). The load forecast for the NWPP is shown below.

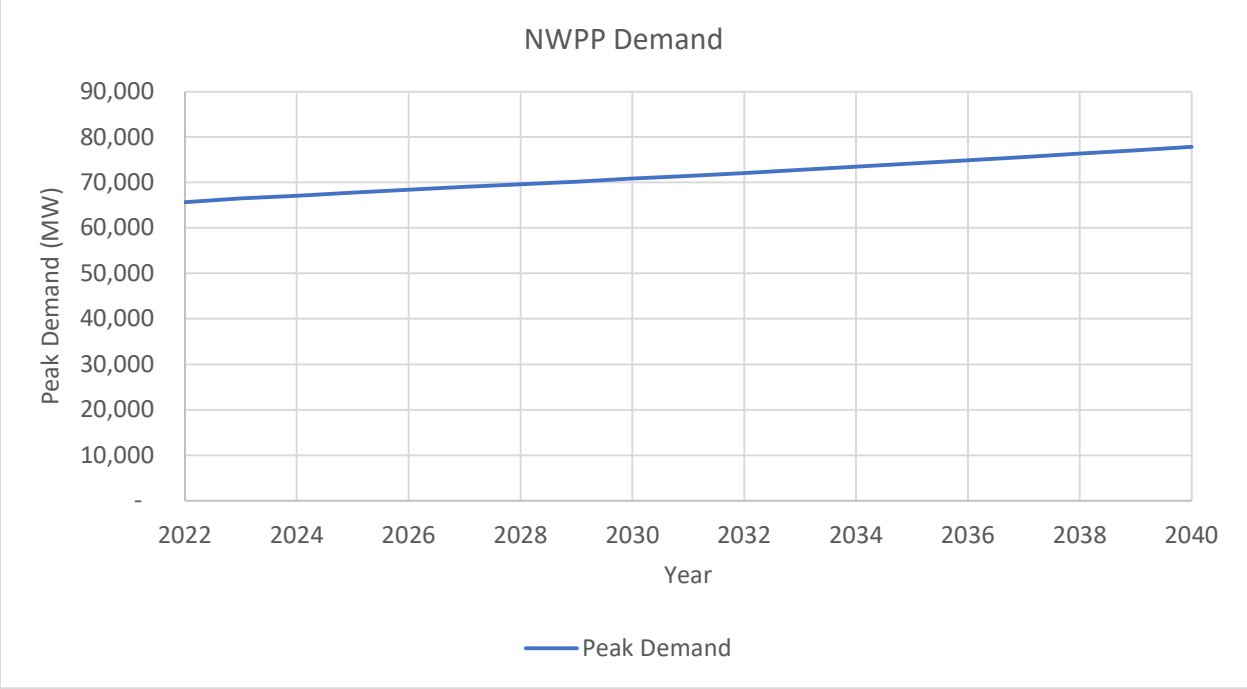

Figure 11. Peak load growth in the NWPP.

The EGPS Power Database is used to determine the existing supply stack within WECC and is built off a variety of sources including the EIA 860 and 923. Future generator candidates are derived from the EIA and NREL. Capital cost curves are derived from the NREL Advance Technology Baseline (ATB) and shown below.

Table 3. Summary of new generating technology options used in the PCM.

Region-Technology	Size (MW)	Duration (MWh)	Capacity Factor (%)	2023 Cost ($/kW)
West-Solar	**100**	**-**	**16%**	**1,508**
East-Solar	**100**	**-**	**24%**	**888**
East-Wind	**150**	**-**	**35%**	**1,237**
MT-Wind	**150**	**-**	**40%**	**1,237**
West-Storage	**100**	**400**	**-**	**1,147**
East-Storage	**100**	**400**	**-**	**1,147**
Hybrid Solar + BESS	**100**	**400**	**-**	**1,306**

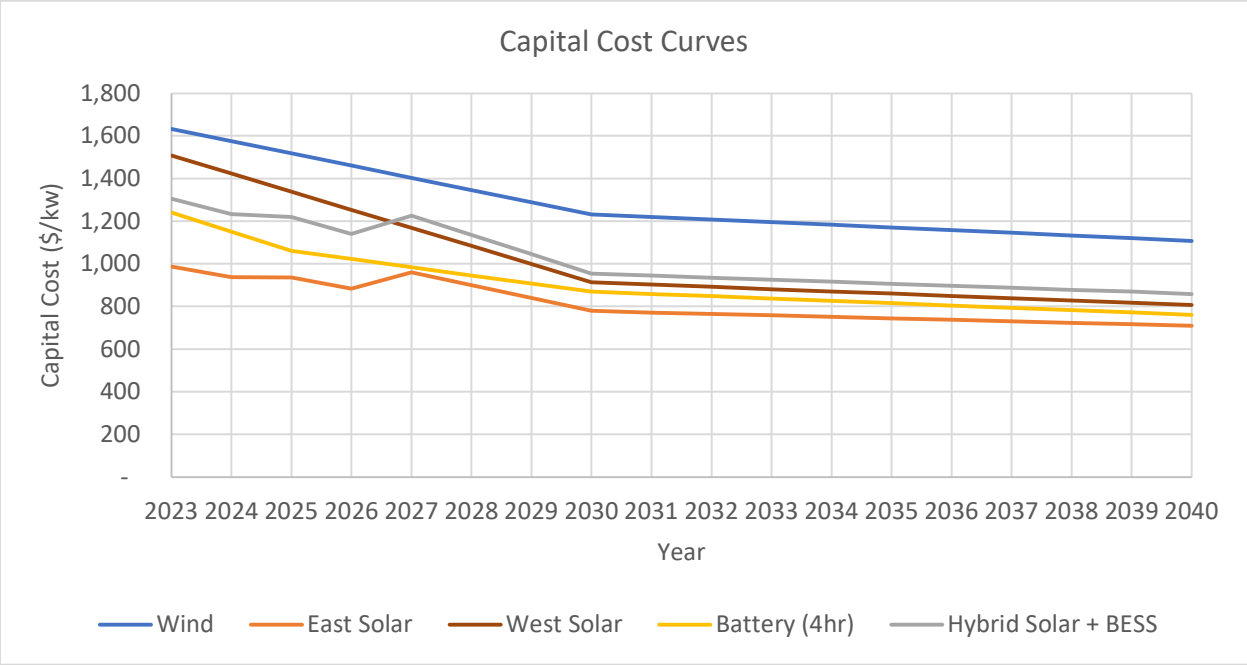

Figure 12. Capital cost curves for various technologies derived from the NREL ATB.

Generator operational and financial properties are derived from the WECC ADS, the CPUC RA and IRP model, and general rules of thumb from the EPA and NREL. Fuel forecasts for thermal generators are derived from the EIA and forward trading curves. The model contains seven natural gas hubs in the west and unit-level gas transportation cost adders.

Clean energy laws are represented in the model through minimum renewable generation constraints similar to RPS constraints. These are summarized below.

Table 4. RPS Targets used in the PCM.

State	Target	Year	Comments
California	**100%**	**2045**	**RPS**
Colorado	**100%**	**2050**	**Clean Energy**
Nevada	**100%**	**2050**	**RPS**
New Mexico	**100%**	**2045**	**Carbon Free**
Oregon	**100%**	**2040**	**RPS**
Washington	**100%**	**2045**	**Clean Energy**

We implemented utility-level constraints on Pacificorp (PACW), Portland General Electric (PGE), and Puget Sound Energy (PSEI) to ensure both state-level laws and individual utility requirements were met. Assuming a blended clean energy technology capacity factor of 30%, the capacity additions for Puget Sound Energy, Portland General Electric, and Pacificorp West are estimated at 3 GW, 4.3 GW, and 4.3 MW by 2030 (assuming 7,756, 11,309, and 11,322 GWh incremental clean energy requirement) and 6.5 GW, 6.8 GW, 5.8 GW by 2040, respectively (assuming 17,054, 17,909, and 15,211 GWh incremental clean energy requirement).

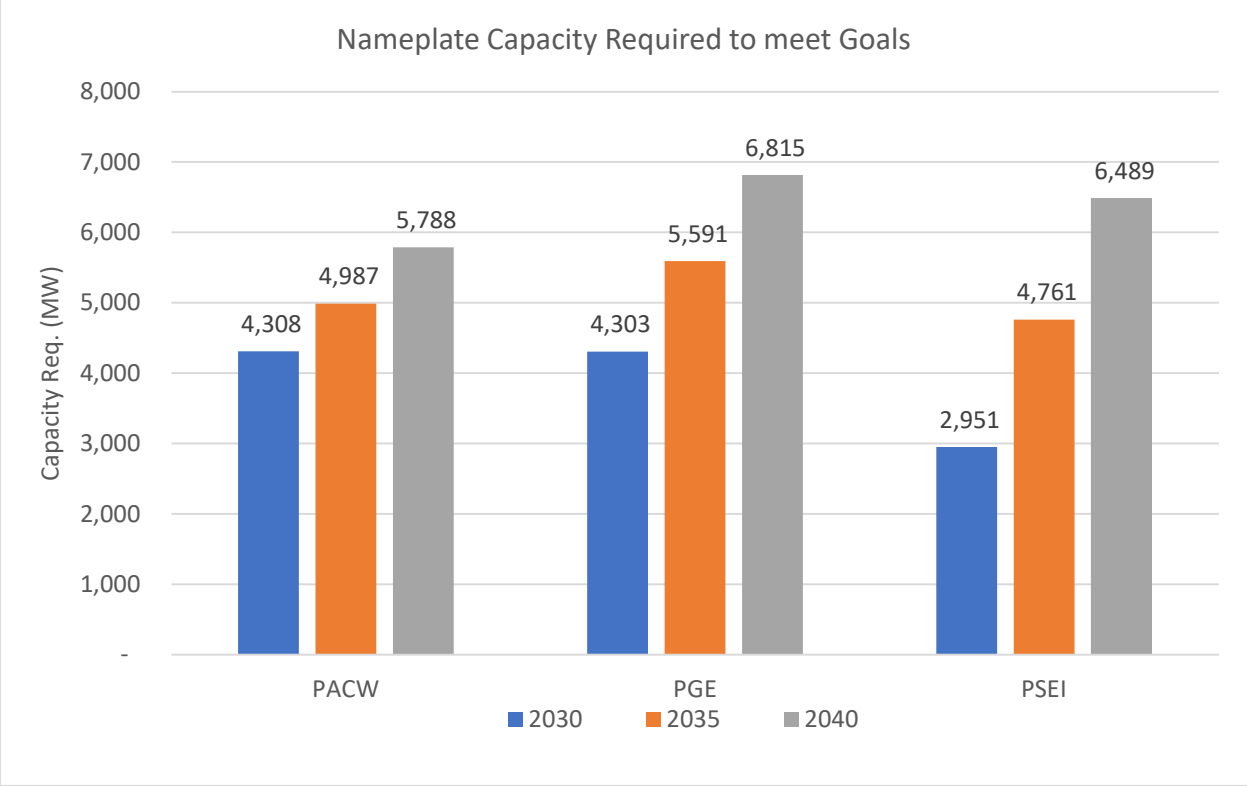

Figure 13. Incremental capacity requirements for utilities in the PNW. Note, assumes a 30% capacity factor.

Our production cost model has been carefully benchmarked to the last three full years of energy data in terms of installed capacity, generation by fuel type, unit-level hourly hydro generation, transmission flows on major paths, and power prices. Our base long-term capacity expansion has been evaluated against publicly available expansion plans including the 2021 NW Power Plan[9].

Our model has several differentiators that benefited this analysis including:

- Separate zones for BPAT into NW, SW, and E with current transmission limits between,
- Hydro model in PNW integrated in PCM,
- Tethered to reality with benchmarking three years, and
- Iterative approach to capacity expansion.

[9] 2021 NW Power Plan, https://www.nwcouncil.org/sites/default/files/2021powerplan_2021-5.pdf

Appendix B. DISCLAIMER

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Attachment 16. Washington State Route 14 Feasibility Review

November 2025

Memo

Date:	Monday, August 14, 2023
Project:	Cascade Renewable Transmission (CRT) Project
To:	Chris Hocker, Cascade Renewable Transmission, LLC
From:	Malia Bassett, HDR
Subject:	**Washington State Route (SR)-14 Feasibility Review**

1.0 Introduction

The energy landscape of the Pacific Northwest region is rapidly changing in response to large coal-fired power plant retirements, state and municipal decarbonization public policy, and regional trends such as population growth, new energy-intensive industries, and vehicle electrification. Oregon and Washington have enacted strong mandates for decarbonization including:

- Washington's Clean Energy Transformation Act (CETA), enacted in 2019, requires all state utilities to eliminate coal-fired generation by 2025, become "greenhouse gas neutral" (i.e., no additional production of greenhouse gases) by 2030, and achieve 100 percent generation using non-emitting renewables by 2045.
- Oregon's House Bill (HB) 2021, enacted in 2021, requires major utilities to reduce greenhouse gas emissions by 80 percent by 2030, 90 percent by 2035, and 100 percent by 2040. It also prohibits site certification for new fossil fuel generation and amendments to existing site certificates that would allow net increase in emissions.

Cascade Renewable Transmission, LLC (CRT) is evaluating construction of an underground transmission line referred to as the Cascade Renewable Transmission (CRT) Project (CRT project). The CRT project would address the need for long-term available transfer capacity across the Cascade Range and help Washington and Oregon meet renewable energy goals associated with climate policies while maintaining electric transmission system reliability.

This memo documents the regulatory context of WSDOT requirements and other environmental constraints for constructing the CRT project in the Washington State Route (SR)-14 right-of-way (ROW).

2.0 Project Description

The CRT project is a high-voltage direct current 1,100-megawatt electric transmission facility interconnecting the existing Bonneville Power Administration (BPA) Big Eddy 500-kilovolt alternating current substation located in The Dalles, Oregon (Eastern Interconnection) to the existing Portland General Electric (PGE) Harborton Substation in Portland, Oregon (Western Interconnection).

In the SR-14 ROW, a land cable would be installed using a combination of open trenching and trenchless construction methods, as determined appropriate along the land segments. Obstacles including roads, railroads, shallow bedrock, and steep hillsides are present along the general route

and would need to be addressed by the selected construction methodologies. It is anticipated that trenchless methods may include, but not be limited to, conventional bore, horizontal directional drilling (HDD), and E-Power® pipe, with the HDD construction method preferred if trenchless installations are required. The cable bundle and fiber optics lines would be installed within conduits configured in a dual 12-inch-diameter arrangement or both cables housed within a single 24-inch-diameter conduit.

Because redundant fiber optics lines would be installed on land, achieving the separation required to avoid common mode failure must be considered where trenchless construction methods are used. It is assumed that the cable bundle and fiber optic lines would be installed approximately 4 to 5 feet beneath the surface where installed by open trench and deeper for trenchless installations (depending on the obstacles and geometry constraints). Where shallow bedrock exists at depths less than the minimum cable burial depth requirements, trenching in rock could be required. Trenched installations in rock may require additional equipment and potential blasting to remove the rock depending on its characteristics, location, and project requirements.

The workspace footprint required to execute the land cable installation would be highly dependent on final route selection, burial depth, and construction methods chosen to address the conditions and any obstacles along the selected route.

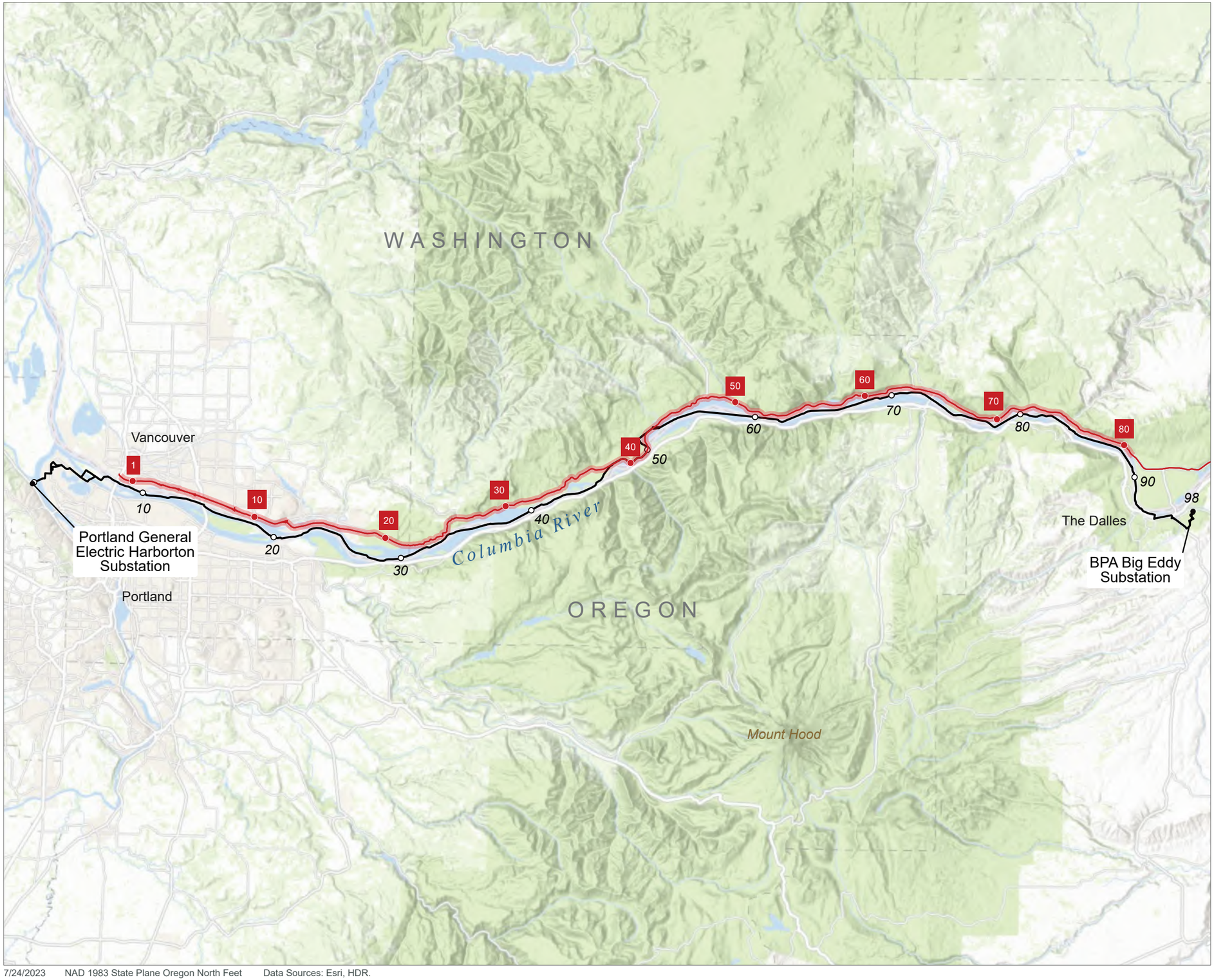
3.0 SR-14 On Land Route Option

CRT, LLC evaluated a land route primarily within Washington State that follows the existing SR-14 transportation corridor between Mile Post (MP) 0 in Vancouver, WA and MP 81 in Lyle, WA (SR-14 project route) (Figure 1). The SR-14 transportation corridor is managed by the Washington Department of Transportation (WSDOT).

The SR-14 project route runs west-east and parallels the northern side of the Columbia River for the entirety of the CRT project alignment, approximately 81 miles. The entirety of SR-14 is part of the National Highway System (NHS), an important infrastructure to the national economy and mobility in this area. It is estimated that SR-14 has an Annual Average Daily Traffic (AADT) that is as low as 2,800 daily trips around mile post 47.5 to as high as 78,000 daily trips around mile post 7.9 (WSDOT, 2022a). The Federal Highway Administration (FHWA) oversees the NHS system but delegates maintenance and operation to states. In this context, the WSDOT manages maintenance and operation of SR-14, including utilities within the ROW of state highways.

The SR-14 project route is theoretical and actual placement of the cable has not been identified. This analysis assumes that the cable would need to be placed in the SR-14 right-of-way (ROW) similarly to placement in other roadways, as described below.

Figure 1
SR14 Location Map



- RIVER MILES (MILES)
- SR-14 MILE MARKER
- PROPOSED ALIGNMENT
- WSDOT SR-14
- SR-14 STUDY AREA (0.25 MILE)

CASCADE RENEWABLE TRANSMISSION

HDR

0 — 10 mi

7/24/2023 NAD 1983 State Plane Oregon North Feet Data Sources: Esri, HDR.

3.1 Typical On Land Construction Methods

The SR-14 project route would be installed using a combination of open trenching and trenchless construction methods, as determined appropriate along the land segments. The SR-14 project route includes a myriad of obstacles: tunnels, roundabouts, bridges, surface water, stream crossings (approximately 353 total), and rockslides that would need to be addressed by selected construction methodologies.

The project team anticipates that trenchless methods could include, but not be limited to, conventional bore, horizontal directional drilling (HDD), and E-Power® pipe, with the HDD construction method preferred if trenchless installations are required. The cable bundle and fiber optic lines would be installed within conduits configured in a dual 12-inch-diameter arrangement or both cables housed within a single 24-inch-diameter conduit.

3.2 Physical and Environmental Constraints and Feasibility

Below is a discussion of the regulatory context of WSDOT requirements and other environmental constraints for constructing the CRT project in the State Route (SR)-14 right-of-way (ROW).

3.2.1 WSDOT Control Zones and Variances

The SR-14 project route would be required to comply with WSDOT Control Zones and Variances. WSDOT requires that all utility installations within the highway ROW be in accordance with the control zone guidelines (WAC 468-34-350), which govern the location of utilities within the ROW, including new installations for utility projects. WSDOT's control zone policy is that all utility objects must be located outside of the Control Zone, defined as the total roadside area (WSDOT Utilities Manual M22-87.07, 900.09 Project Applications, New Utility Facility Construction (a)(1)). WSDOT Control Zone Policy recognizes that practicable options for utility accommodation are sometimes limited to the ROW under WSDOT's control and allows for certain measures, including variance approvals of utility objects, with due consideration for the safety of highway users.

All new utility objects are required to be constructed outside the Control Zone unless a variance is authorized. In addition, utilities are required to relocate or mitigate existing objects within the Control Zone during WSDOT highway projects, utility reconstruction, and Franchise Renewal/Consolidation, or if the department determines that any existing objects must be relocated or mitigated for the safety of highway users (WSDOT Utilities Manual 900.02 Clear Zone vs. Control Zone).

A Clear Zone is defined in the WSDOT Utilities Manual as "the total roadside border area, available for use by errant vehicles, starting at the edge of the traveled way and oriented from the outside or inside shoulder (in median applications) as applicable…" (M-22.87, Chapter 9). From a technical standpoint, Control Zone and Clear Zone are synonymous in that the criteria and methodology used to calculate the two are identical. The distinction is one of policy in applying measures to achieve compliance. The differing policies are based on the recognition that accommodation of utility facilities within the state highway ROW is in the public interest when such use and occupancy do not adversely affect highway operations or safety.

WSDOT recognizes that conditions may arise that make it impracticable to comply with Control Zone requirements. Variances from such compliance may be allowed on a case-by-case basis when clearly justified, as specified in the following sections. Examples of conditions rendering compliance impracticable include:

- Inadequate ROW to accommodate utility objects outside the Control Zone.
- Physical limitations due to terrain or topography.
- Unjustifiably high costs to relocate or underground the utility facility.

WSDOT requires that the installation not adversely affect the design, construction, stability, structural integrity, traffic safety or operation of the highway (WAC 468-34-110 (7)(a)).

The proposed SR-14 project route would need to comply with WSDOT Control Zone or demonstrate the need for a variance at each problematic location.

3.2.2 WSDOT Longitudinal Installation Requirements

WSDOT requires that "longitudinal installations should be located on a uniform alignment and grade as near as practicable to the ROW line so as to provide a safe environment for traffic operation and preserve space for future highway improvements or other utility installations" (WAC 468-34-130 (2)). It is our interpretation that this is meant to establish general policy that longitudinal utilities must be located outside of the operating roadway that includes paved lanes, paved shoulders, inside guardrail, and the median of a divided highway. Therefore, this requirement precludes placement of utilities within the SR-14 road prism.

Conceptually, this requirement limits utility placement within the ROW to the area outside the SR-14 ROW. Distances between the SR-14 ROW boundary and varying terrain (rock, slopes, causeways) are, in some areas, nonexistent. In these instances, the construction team would not have enough space to install the cable outside of SR-14 ROW.

The SR-14 project route would traverse numerous locations where steep or vertical basalt rock face exist; in some locations, rock faces several hundred feet high run along the highway close to the paved shoulder. Open trenching through these areas would require blasting intact basalt for excavation. The steep and sometimes vertical rock faces are comprised of fractured basalt which is susceptible to rockfall. Blasting in these locations has a high likelihood of loosening rock during blasting which could fall during construction or years or decades later. This would create rockfall hazards during trench excavation and for years to follow.

Therefore, the project would not be able to comply with (WAC 468-34-130 (2)) because a) project construction outside of the road prism would be dangerous for traffic operations during construction and operation and b) project construction within the road prism would limit space for future highway improvements or other utility installations.

3.2.3 WSDOT Traffic Obstruction and Nighttime Work

WSDOT requires all utility installations to "keep interference with traffic to an absolute minimum." On heavily traveled highways, construction that interferes with traffic shall not be allowed during periods of peak traffic flow. Peak traffic flow is from about 7 – 9 am and 3 – 6 pm on weekdays. On weekends, peak traffic is from 10 am – 12 pm and 4 – 6 pm (WSDOT, 2022b). Work shall be planned so that closure of intersecting streets, road approaches or other access points is held to a minimum (WAC 468-34-340 (a)).

SR-14 is primarily a two-lane highway; project construction would require the closure of at least one lane. Avoidance of road closure would not be possible due to the space requirements and the limited area or environmental factors outside the SR-14 road prism. Additionally, detours would be difficult,

or nearly impossible, since roads that branch off from SR-14 are either private, dead ends, or would not be suitable as efficient detours for the mobility requirements that SR-14 satisfies in this area.

To comply with WSDOT traffic obstruction requirements, the project would be required to first obtain permission from WSDOT to close a lane on SR-14. The level of interference with SR-14 traffic flow would render this approval unlikely for work during daytime hours. Subsequently, the project would be required to obtain noise variances from jurisdictions along the SR-14 project route to do nighttime work (the cities of Vancouver, Camas, Washougal, North Bonneville, Stevenson, Carson (census designated), White Salmon, Bingen, Lyle (unincorporated), Dallesport (unincorporated); Clark, Skamania, and Klickitat Counties).

All jurisdictions along SR-14 follow state noise regulations, as outlined in WAC 173-60-040. Class C (industrial) noise sources have a maximum allowed noise of 60 dBA (A-weighted decibels) entering residential areas, 65 dBA entering commercial areas, and 70 dBA entering other industrial areas. Temporary construction sites are exempt from these provisions, except for the noise impacts on residential areas between 10 pm – 7am (WAC 173-60-050).

WSDOT has indicated that work on SR-14 would likely need to occur at nighttime to minimize the traffic impacts of closing one lane. Noise during construction would be created for periods of eight standard 8-hour shifts during trenching and 10- to 12-hour shifts during HDD. The sources of project noise would be from HDD drilling techniques and from the trenching equipment. Ambient noise levels are most restricted by local jurisdictions during nighttime.

There are several locations along SR-14 that may be especially sensitive to noise. These include the Riverview Senior Living Center around milepost 3.9 (about 250' feet from the highway); the Little Lamb Pre-School and Hope Learning Center at milepost 16.1 (400’ away); Skamania Elementary School at milepost 33.2 (380’ away), and at milepost 44.2 the Mid-Columbia Start and Early Head Start School and Stevenson Elementary (365’ away). Furthermore, the Ambulance Service of Skamania, which provides critical transport services for those who live far from hospitals but require immediate medical attention, is located around milepost 44.2 and is about 150’ from SR-14.

At best, the project would be required to be constructed during the night to avoid SR-14 operation obstacles. This would cause the work to be slow, limited, and create nighttime noise.

3.2.4 WSDOT Bridge and Tunnels Crossings

WSDOT has strict requirements for attaching utility installations on highway structures, such as bridges and tunnels (WAC 468-34-270). Relevant requirements include:

- Aesthetic design compatibility considered for each individual bridge.
- Structural compatibility – the bridge must be able to support the proposed utility attachment load and cannot compromise the bridge features.
- Must be amenable to bridge maintenance – access of any part for maintenance, painting, or repair.
- Cannot reduce the critical clearance of the structure
- Should be beneath structures floor, between girders or beams
- Avoid attaching to the outside of the bridges
- Not create noise from vibration
- Size, attachment methods and sealing needed

There are approximately 54 bridges (5.02 miles) along the SR-14 project route, ranging in age from 11 years to 107 years. Some bridges, such as the Cape Horn Bridge, are bolted to the side of the Basalt Rock cliff. Most of the SR-14 bridges could be compromised by the addition of a utility line. Further, two bridges – Klickitat River Bridge #14/212 (MP 75); and Horsethief Canyon Bridge #14/222 (MP 86.12) – are contributing elements to SR-14's historic significance, which would moreover limit the introduction of a utility line.

There are 8 tunnels (.39 miles total) along the SR-14 project route; seven were built in the 1930s and one was built in 1978 (National Tunnel Inventory, March 2022). Tunnels present added construction and maintenance risks in that the construction limits are confined to walls on each side and above. The SR-14 tunnels could be compromised by the introduction of construction within them, but also the integrity of the tunnel's purpose – like when they are below a rail – could be compromised. Utility installations on or near any bridges or tunnels require review and written approval by the WSDOT HQ Bridge and Structures Office prior to application approval.

Additionally, along the SR-14 project route there are numerous crossings over bridges, retaining walls, wet or rocky terrain or locations where highway drainage would be affected (WAC 468-34-190(2). The project would be required in some locations to go around these features where they are impossible to avoid. For example, in the City of Stevenson between Mile Post (MP)-44 and MP-42 and again at MP-50 to MP-49, there are approximately two miles of causeway where no alternative exists to constructing around the drainage-influencing features. Access for cable maintenance could also risk the integrity of the bridge, making repair of the bridge an added risk. Additionally, for the bridges that are aged and need replacement over the life of the project, bridge replacement would interfere with the project and cause reliability issues to service users.

During project operation, maintenance in the two-lane tunnels would require detours, some of which are as much as an additional 99 miles to avoid the tunnel, ultimately compromising the SR-14 NHS and the safety of highway users.

Therefore, even if the project could comply with WAC 468-34-270 through construction methodologies, the number of crossings is significant and would delay the project to the extent that it is not possible to meet its objective judiciously.

3.2.5 WSDOT Operations

WSDOT requires utility installations to locate in such a way that minimizes the need for later utility adjustment in order to accommodate future highway improvements. WSDOT also requires permit access for servicing such utility lines with minimum interference to highway traffic and requires that those utilities must be located in accordance with the control zone guidelines (WAC 468-34-130(1)).

Additionally, WSDOT prioritizes unplanned issues, such as rockslides, to be approached with WSDOT interests first. This could potentially result in reparation of damages to the project being put on hold until WSDOT is done with needed repairs. During construction, this could also result in construction delays.

Conflicts with installed utilities frequently occur as highway infrastructure needs increase and WSDOT undertakes capital improvements to meet additional transportation demands. Dealing with these utility conflicts in the project delivery process often results in the expenditure of limited department resources on issues not directly related to highway improvements. To minimize the impact of those additional resource expenditures, WSDOT has created a reimbursement policy that defines how to recover department expenses related to utility accommodation and construction

conflict resolution (WSDOT Utilities Manual M22-87.01, December 2008 - 800.01). Per this policy, reimbursement will be made by the utility owner for select costs that WSDOT incurs in dealing with existing utilities that come into conflict with the delivery of WSDOT capital highway improvement programs (800.02).

Therefore, the project becomes impractical in the context of requirements to accommodate WSDOT utility accommodations and future highway improvements over the 81 miles of the project along SR-14. These requirements could stall construction for an undetermined amount of time. Further, an unprecedented, but likely a large number, of utility conflicts would present an operational project expense that is unlikely to be favorable and could also potentially conflict with the reliable service operation needed for the project.

3.2.6 Cultural Resources

In 2009, SR-14 was determined eligible for listing in the National Register of Historic Places (NRHP) by the FHWA. Section 106 of the National Historic Preservation Act (NHPA) requires historic properties listed in or eligible for inclusion in the NRHP or Washington Heritage Register and to consult with the State Historic Preservation Officer (SHPO) at the Washington State Department of Archeology and Historic Preservation (DAHP) if it appears that a proposed project may cause any change, whether beneficial or adverse.

The SR-14 (North Bank Highway) is within the Columbia River Gorge National Scenic Area on the north shore of the Columbia River bound roughly by MP 24 and 78 within the Columbia Gorge Natural Scenic Area in Skamania and Klickitat counties.

The 2003 FHWA inventory of SR-14 found the following contributing elements include:

- Broughton Lumber Co. Flume;
- Rock Walls Nos. SR 14-05, 07, 08, 09 and 10;
- Shaddox Spring Roadside Improvement No. 14-03;
- State Road No. 8/Sam Hill Road Segment;
- Klickitat River Bridge #14/212 (MP 75); and
- Horsethief Canyon Bridge #14/222 (MP 86.12).

Two sections along the SR-14 project route were identified as non-contributing elements between approximately mileposts (MP) 39 and 40 and MP 62 and 64. Combined, these are only three miles of the 81-mile route, 3.7% of which would traverse along SR-14 project route.

A way to avoid or mitigate cultural resources along SR-14 project route would be to adjust the route to stay in the road prism. However, as noted above, routing exclusively within the road prism is infeasible due to disruption of traffic operations and subsequent traffic safety issues.

3.2.7 Environmental Resources

Within a 0.25-mile radius on each side of SR-14 ROW between MP 0 and MP 81 (SR-14 study area), the following environmentally sensitive features are found (listed below with the percentage of the quarter mile buffer that contains each feature and illustrated in Figure 2):

- Adjacent Parks/Vegetation: 2.4%
- Adjacent Flood zone: 4%
- Adjacent Forestland: 4%

- Adjacent Shoreline Jurisdiction: 24%
- Adjacent Surface Water (including waters and wetlands): 24%
- Adjacent steep slopes (3H:1V and steeper): 25%.

Due to a combination of factors, including the slight bedrock dip to the south (into the Gorge) as well as the saprolitic unit at the top of the Ohanapecosh Formation, the northern wall of the Columbia River Gorge is prone to landslides. At least four major landslide complexes are visible in regional geologic mapping within the study area, some of which are still considered active.

In this region, a high degree of variability in topography and subsurface conditions exists within short distances. Evaluation of the site-specific conditions would be necessary to define the preferable alignment and most appropriate installation method(s). Similar to the other segments, environmental constraints would impact construction method selection. Routing challenges to account for land, wetlands, site preparations, excavation, obstacle crossings, transition locations for river crossings to interconnection points, and steep terrain would be notable for the land cable segments.

During construction, these environmentally sensitive areas would pose both construction constraints and, depending on the exact location and impact of the project, compliance with environmental regulatory requirements. The magnitude of sensitive areas and the length of the project could affect the cable installation location, method, protection, power transfer rating and burial depth. The cable route should be chosen to avoid these areas, if possible. Any existing easements or ownerships, crossing technology, locating specific existing infrastructure, etc. are all issues that need to be addressed for each asset crossed or located near the cable route.

Figure 2
Adjacent Environmentally Sensitive Areas / Hazards
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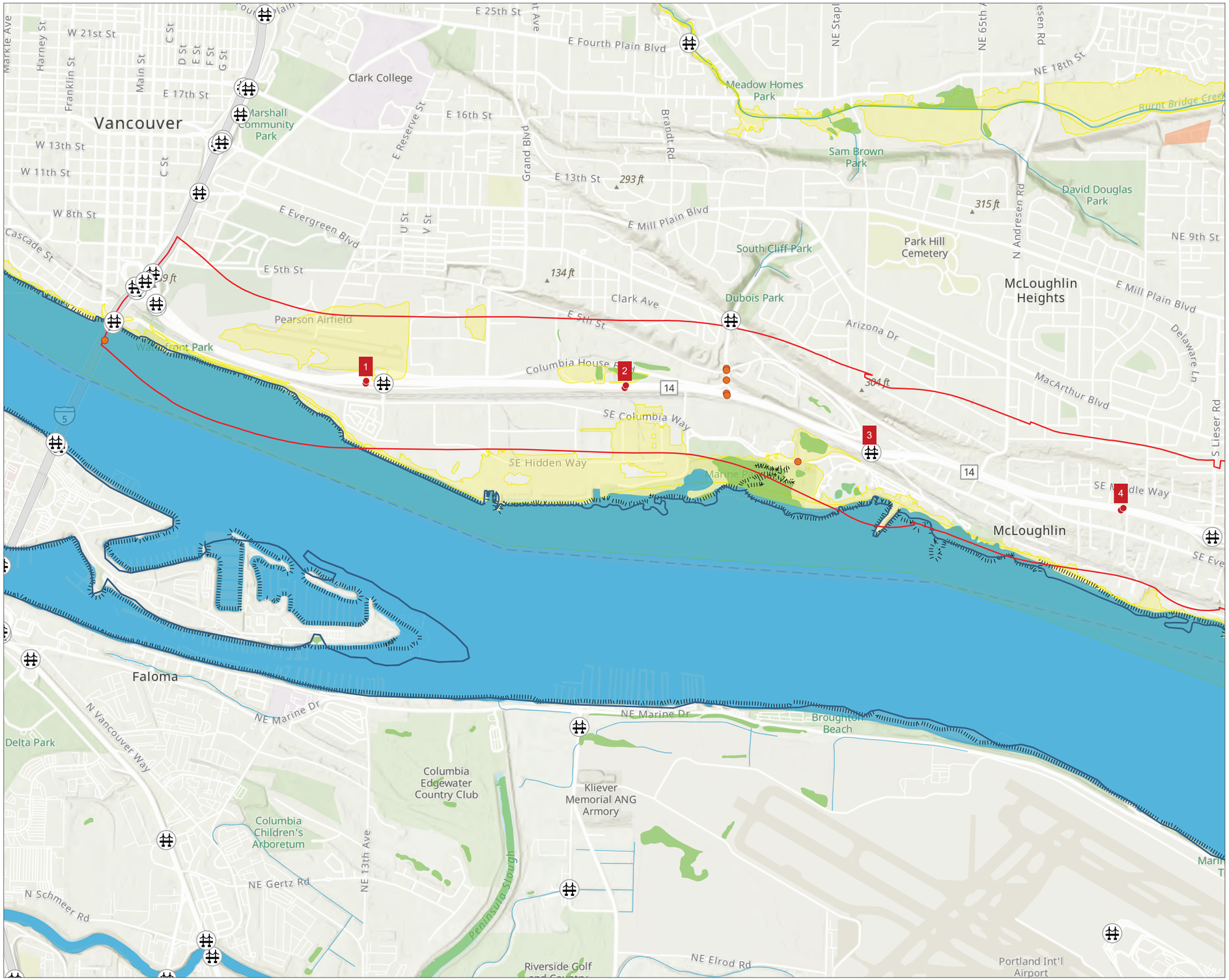

7/24/2023 NAD 1983 State Plane Oregon North Feet Data Sources: Esri, HDR.

- SR-14 MILE MARKER
- STREAM CROSSING
- NATIONAL BRIDGE INVENTORY
- SR-14 STUDY AREA (0.25 MILE)
- ADJACENT FLOODZONE (FEMA)
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- ADJACENT SHORELINE JURISDICTION
- ADJACENT SURFACE WATER

ADJACENT WATERS AND WETLANDS

- MARSH, SWAMP, BOG, PRAIRIE
- RIVER

CASCADE RENEWABLE TRANSMISSION

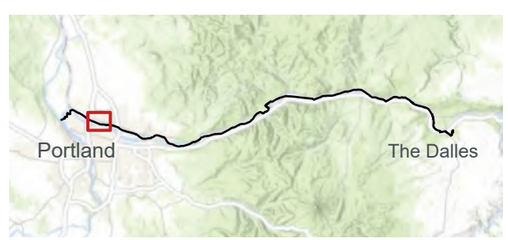

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Figure 2
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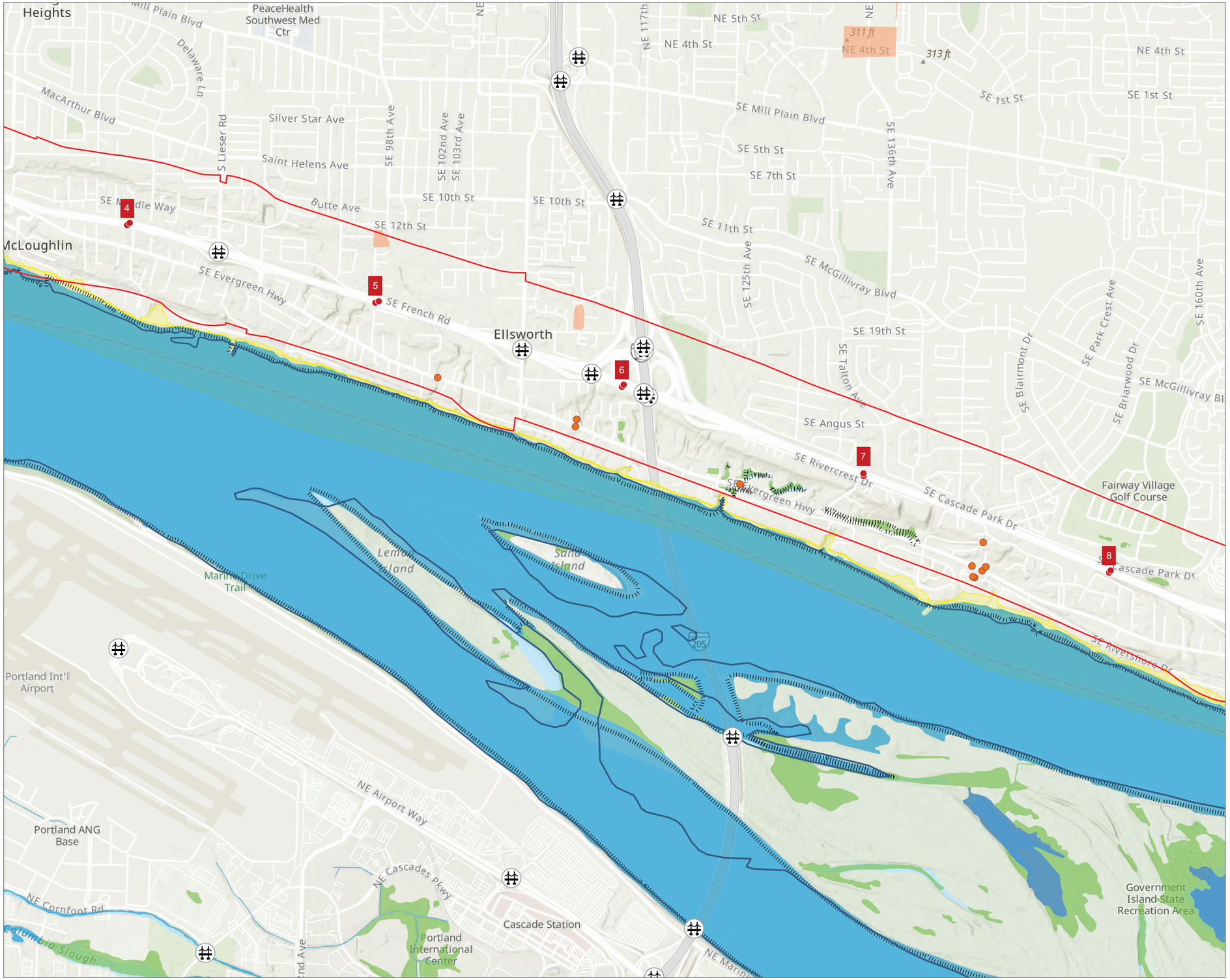

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Figure 2
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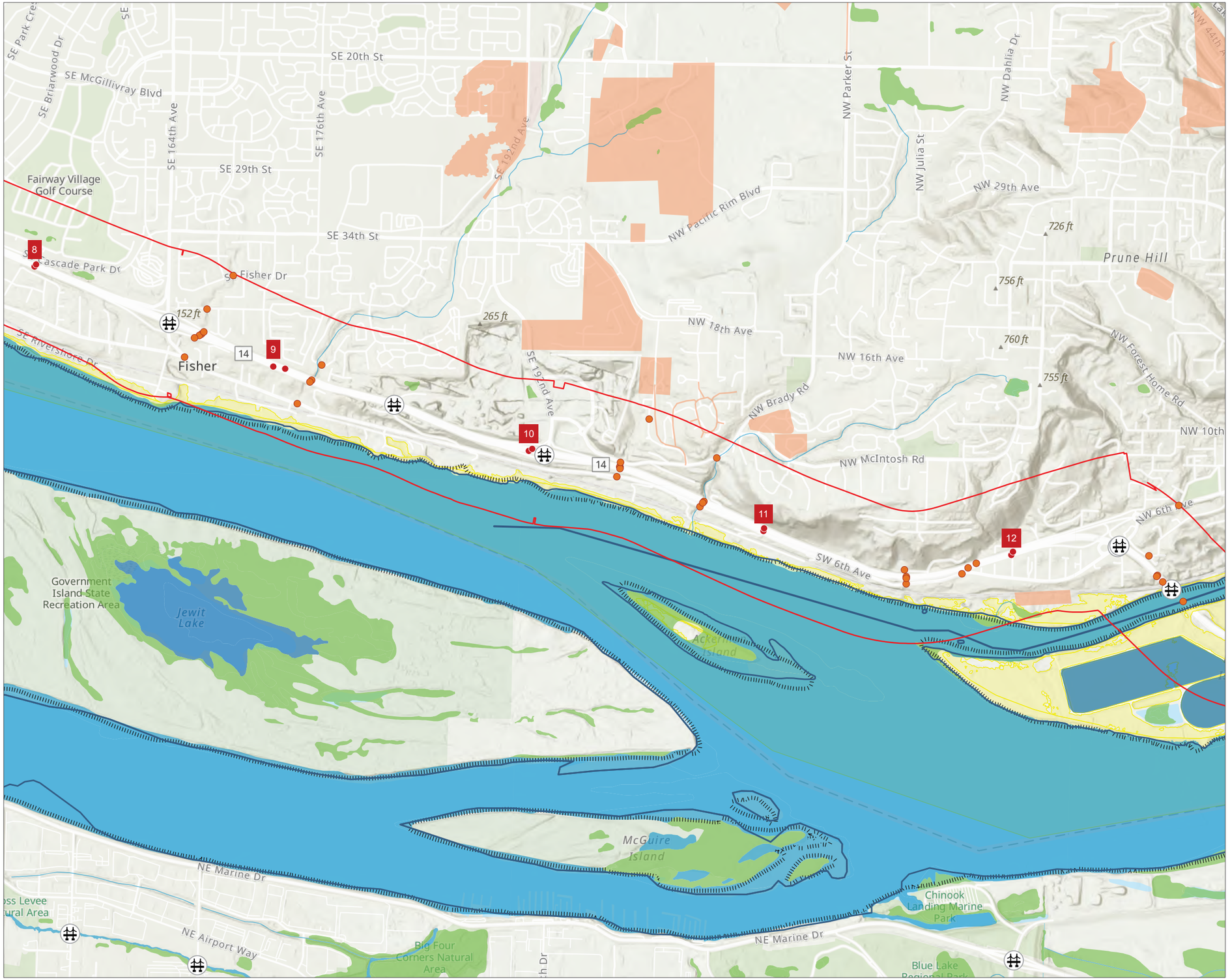

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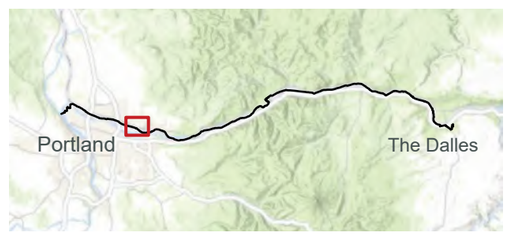

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Figure 2
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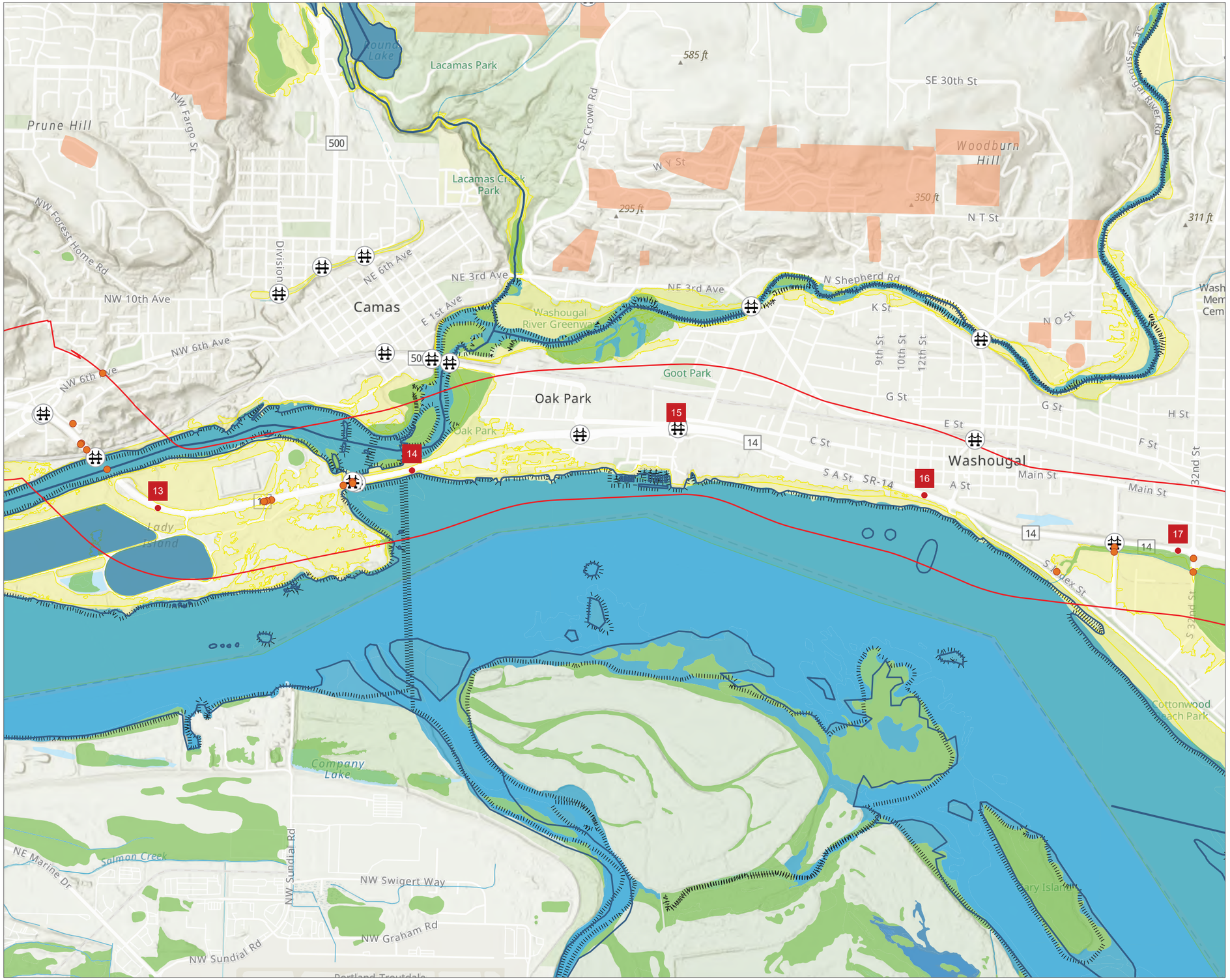

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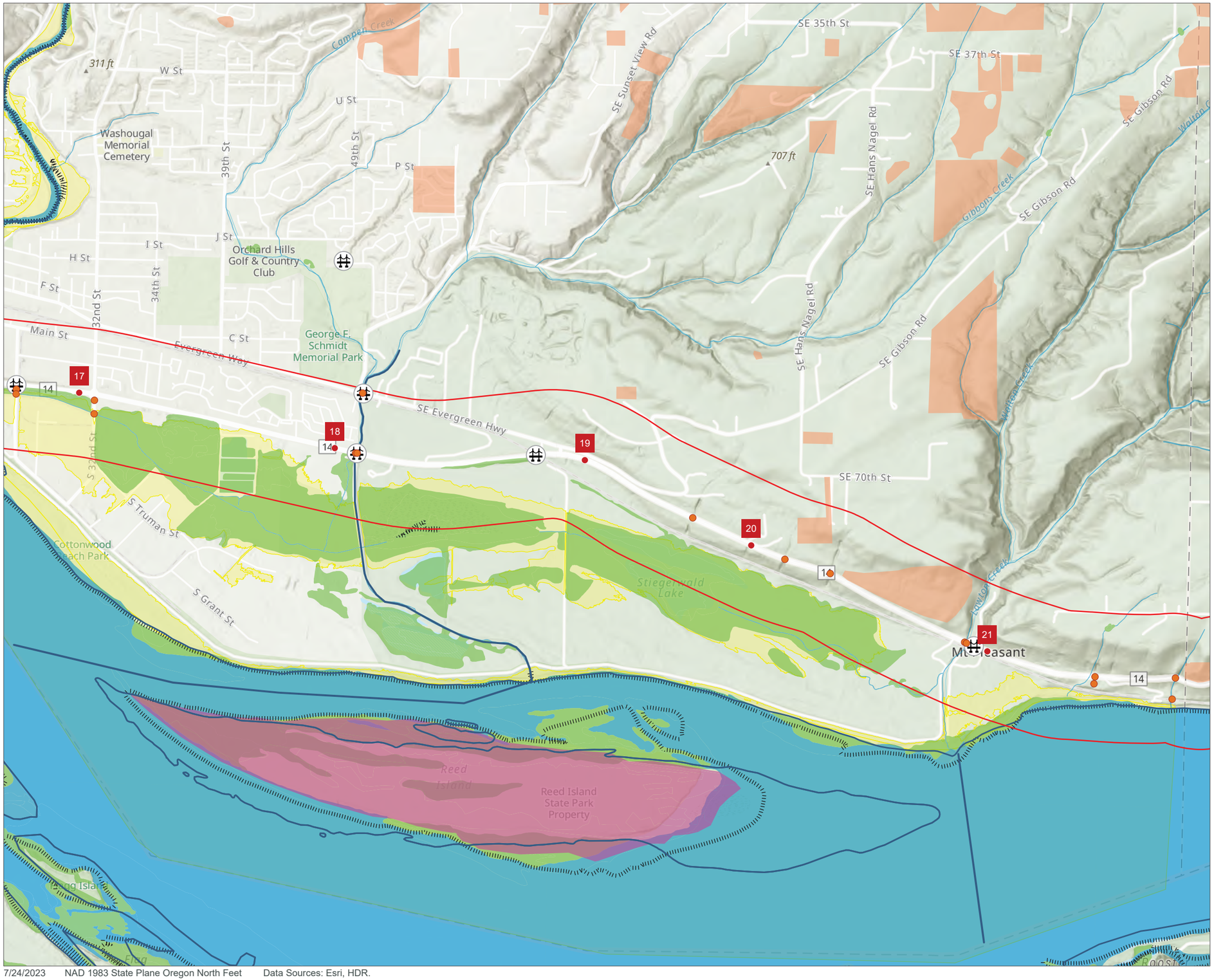

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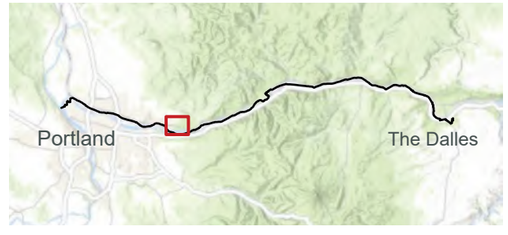

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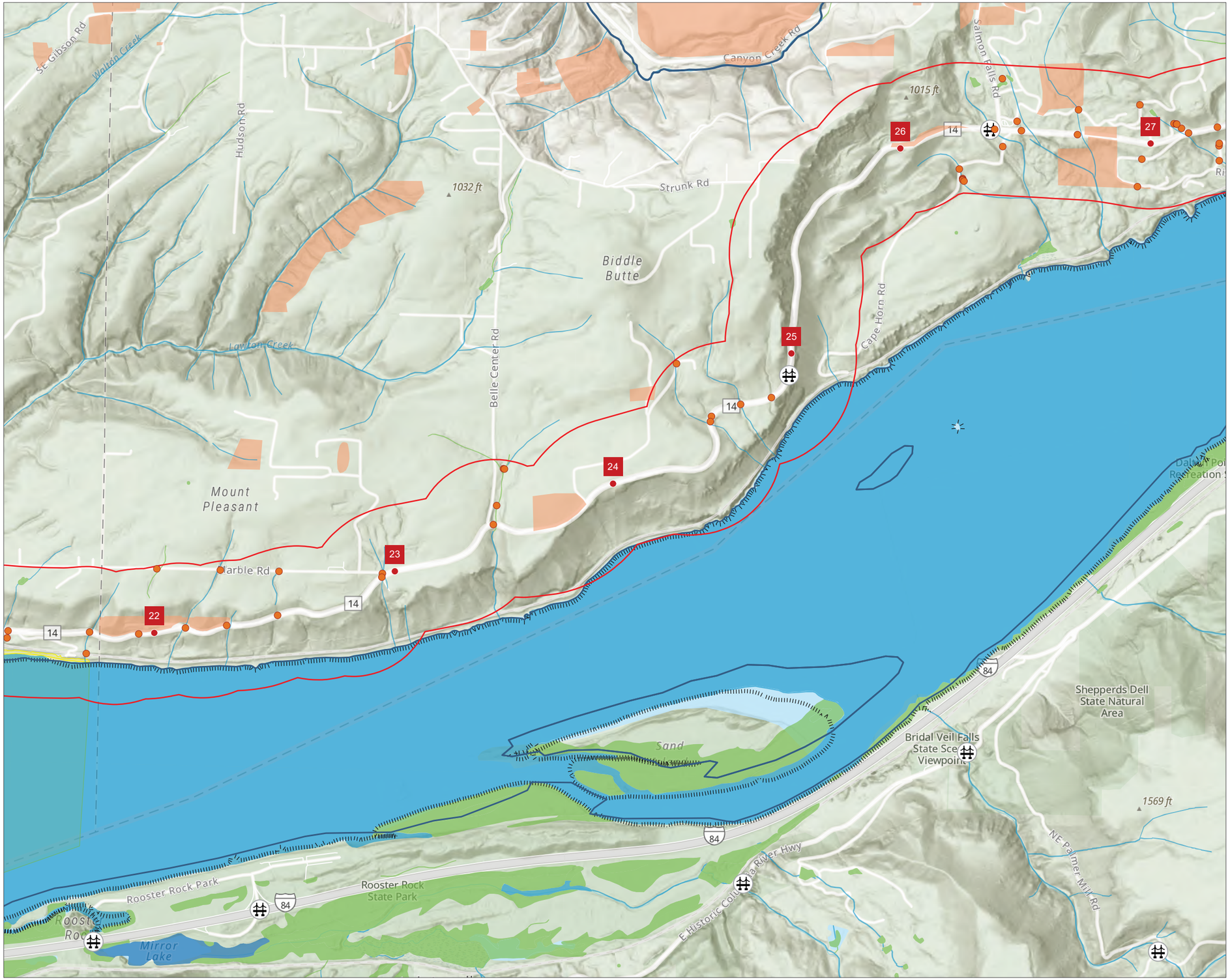

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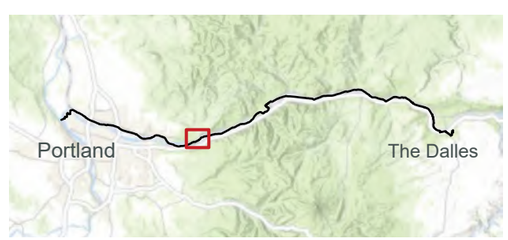

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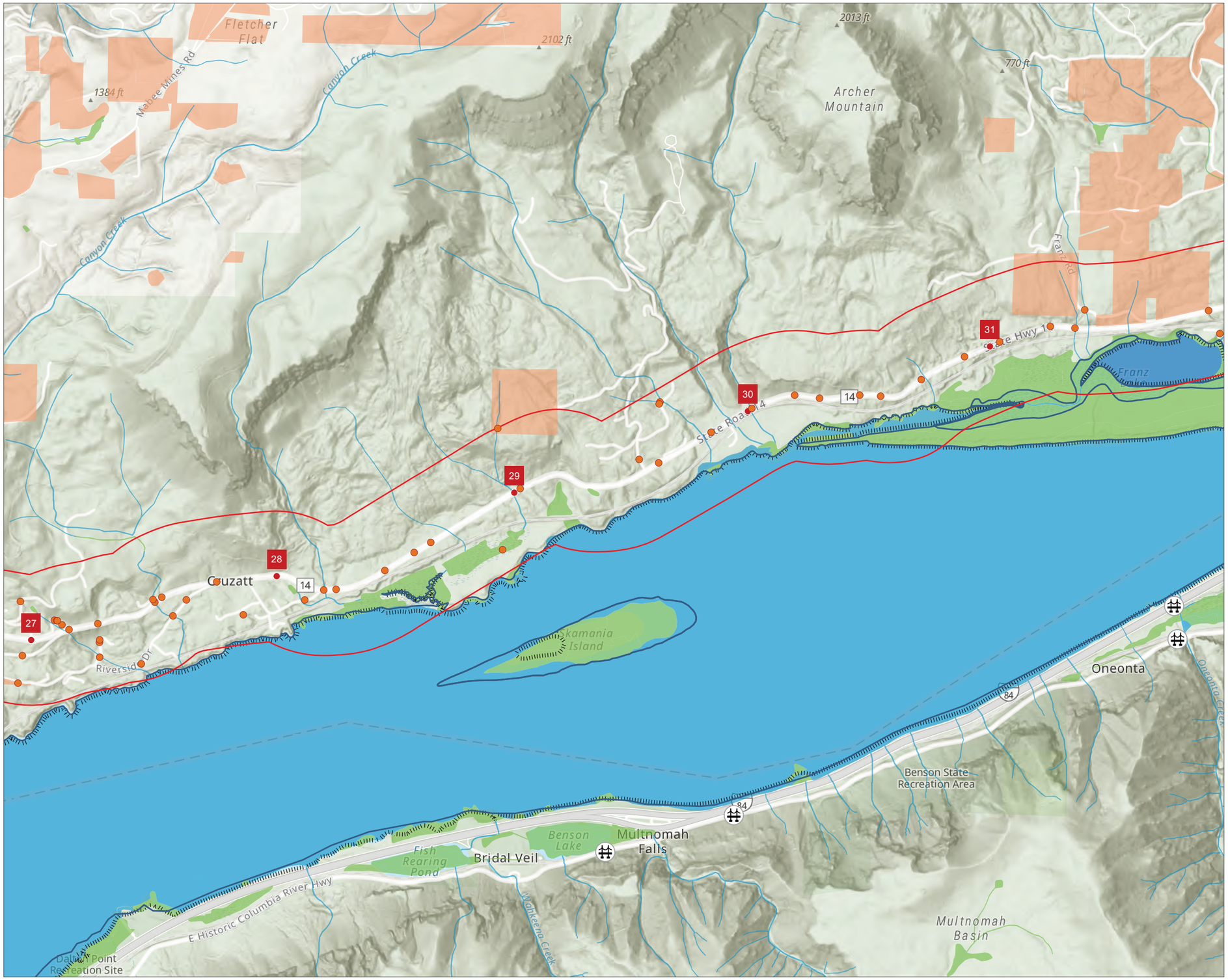

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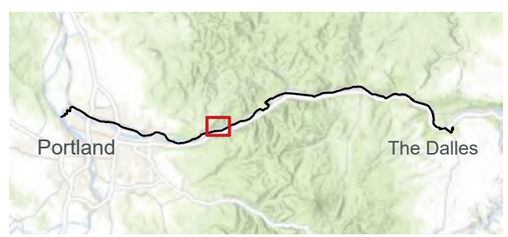

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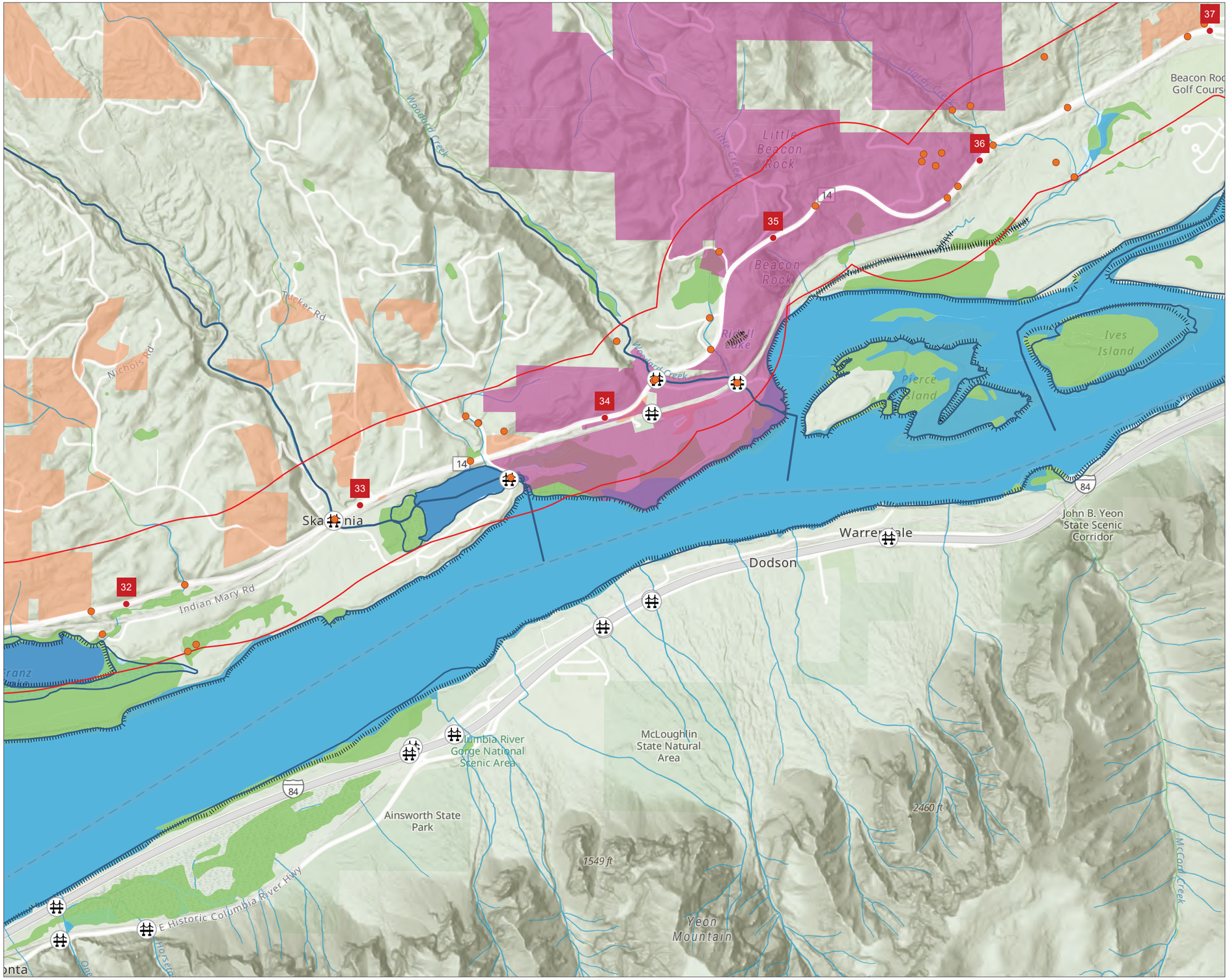

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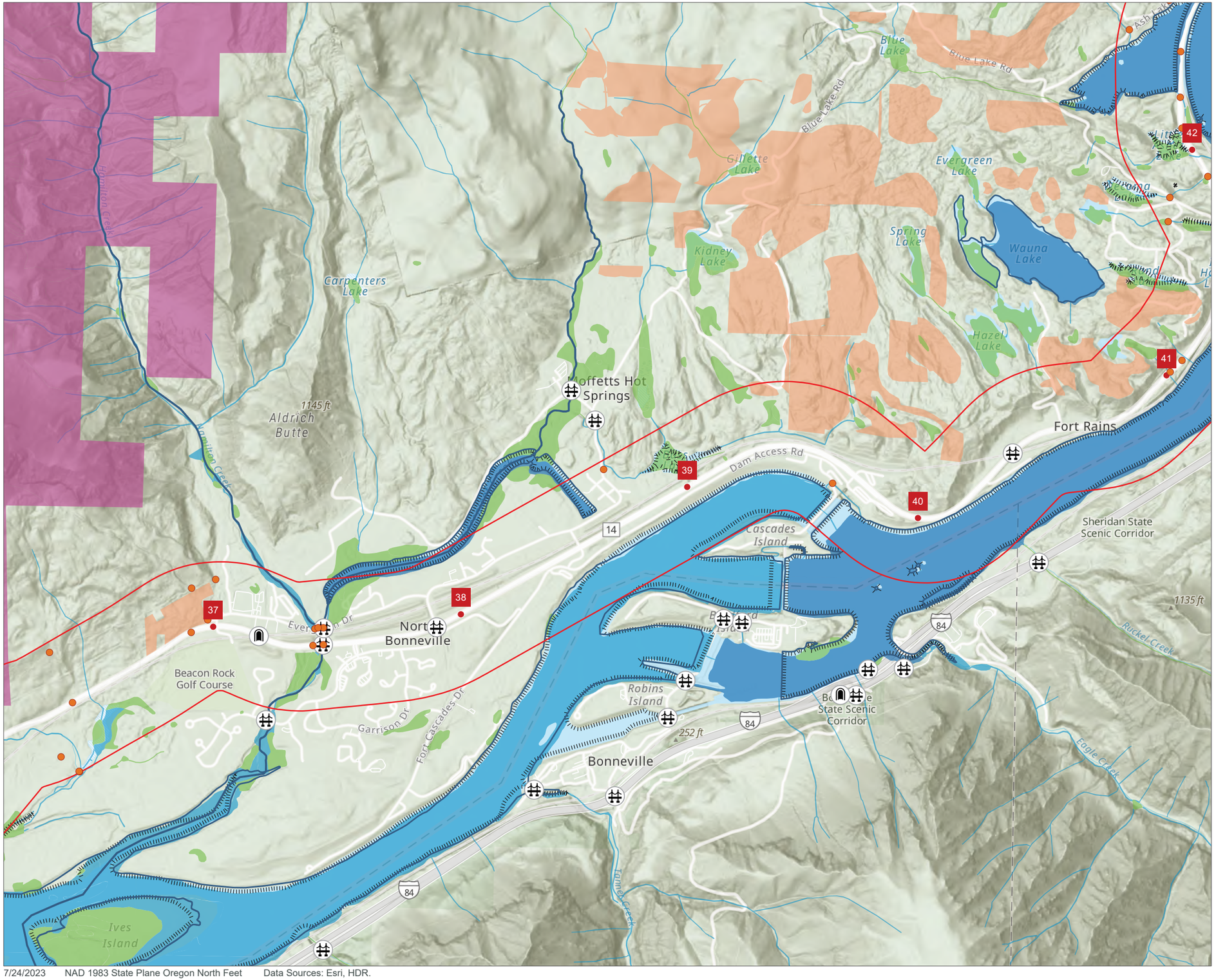

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Adjacent Environmentally Sensitive Areas / Hazards
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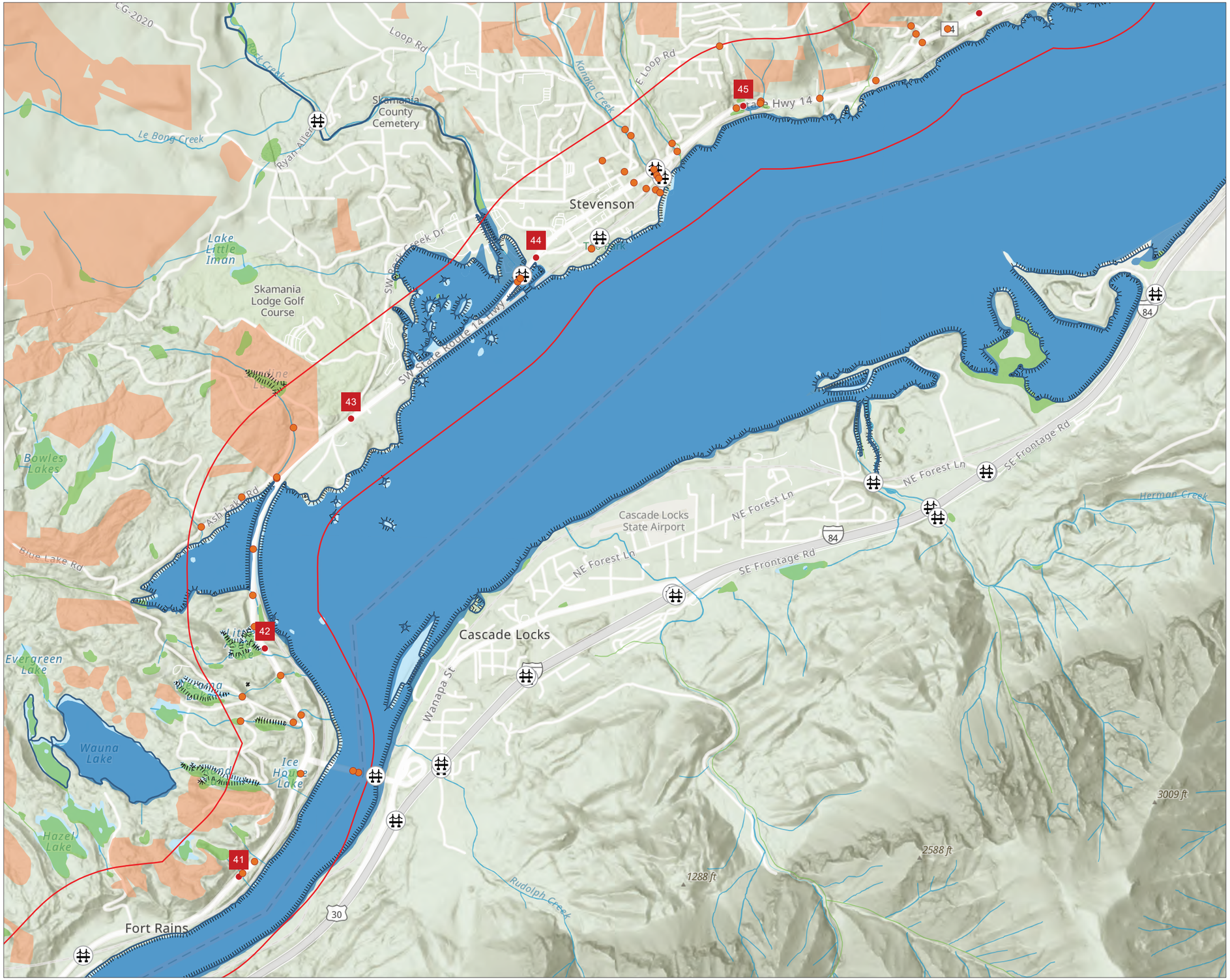

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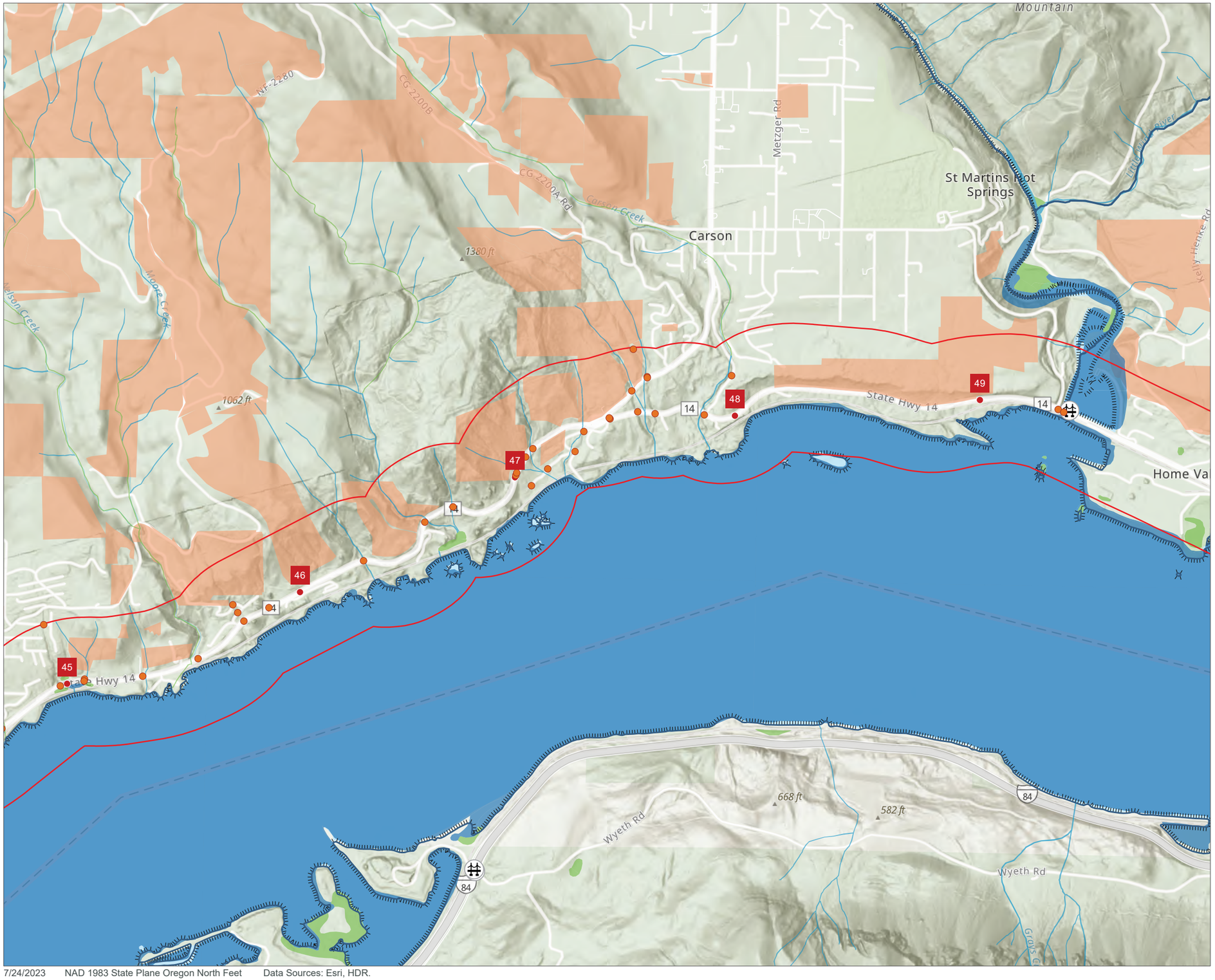

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Figure 2
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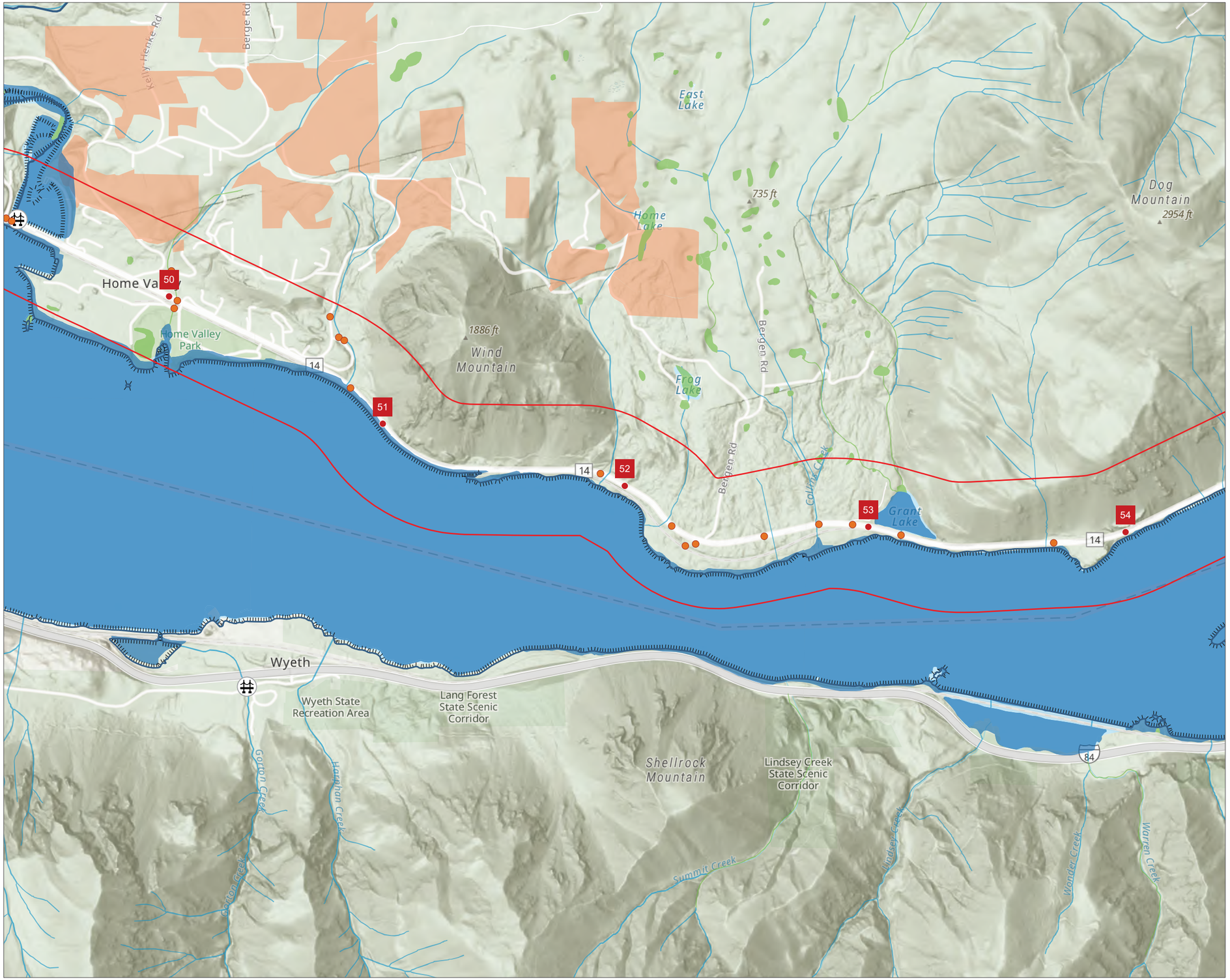

SR-14 MILE MARKER

STREAM CROSSING

NATIONAL BRIDGE INVENTORY

SR-14 STUDY AREA (0.25 MILE)

ADJACENT FORESTLAND

ADJACENT SHORELINE JURISDICTION

ADJACENT SURFACE WATER

ADJACENT WATERS AND WETLANDS

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RIVER

LAKE, RESERVOIR

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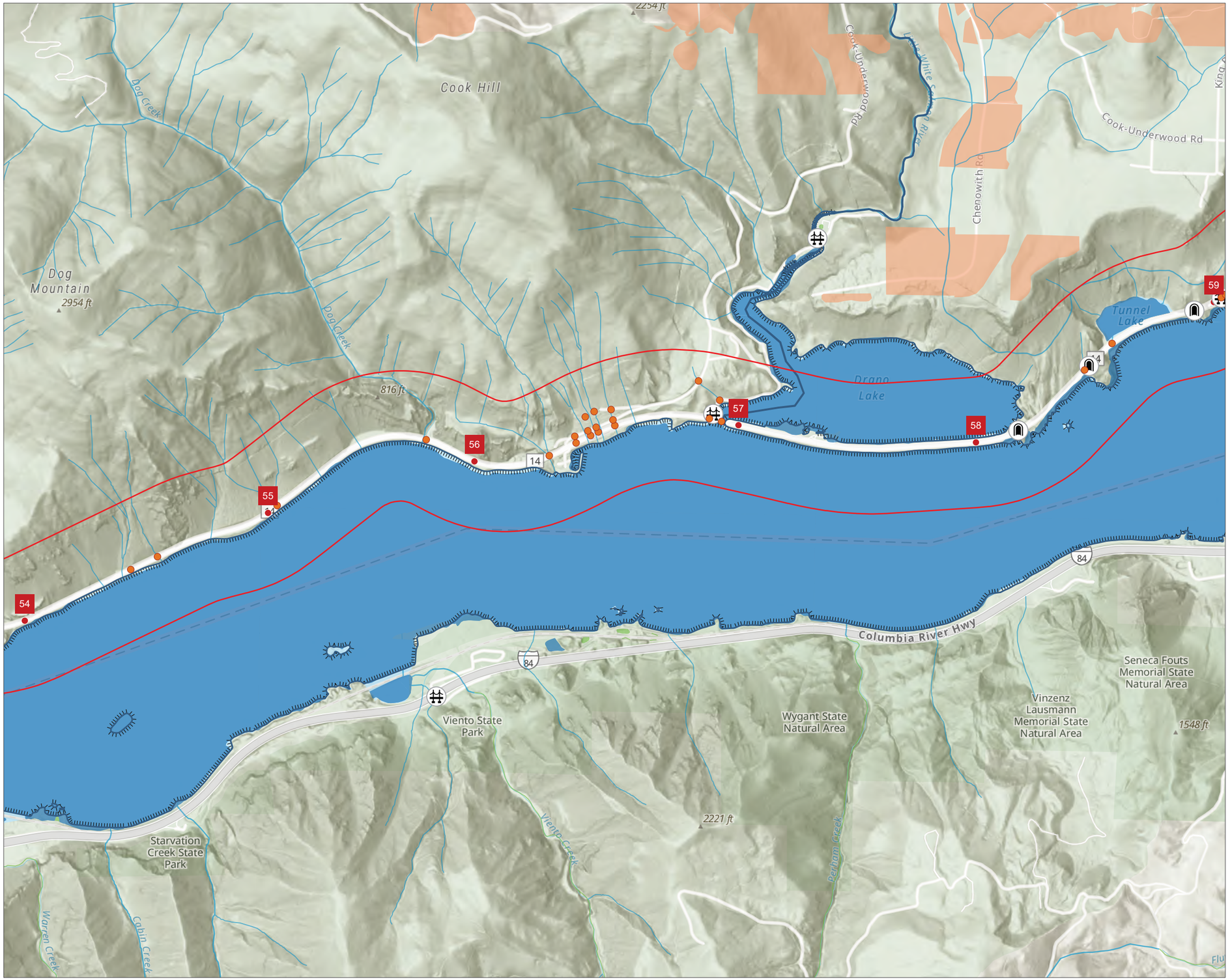

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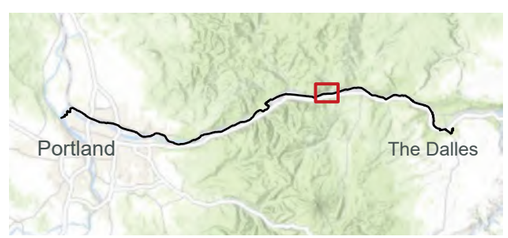

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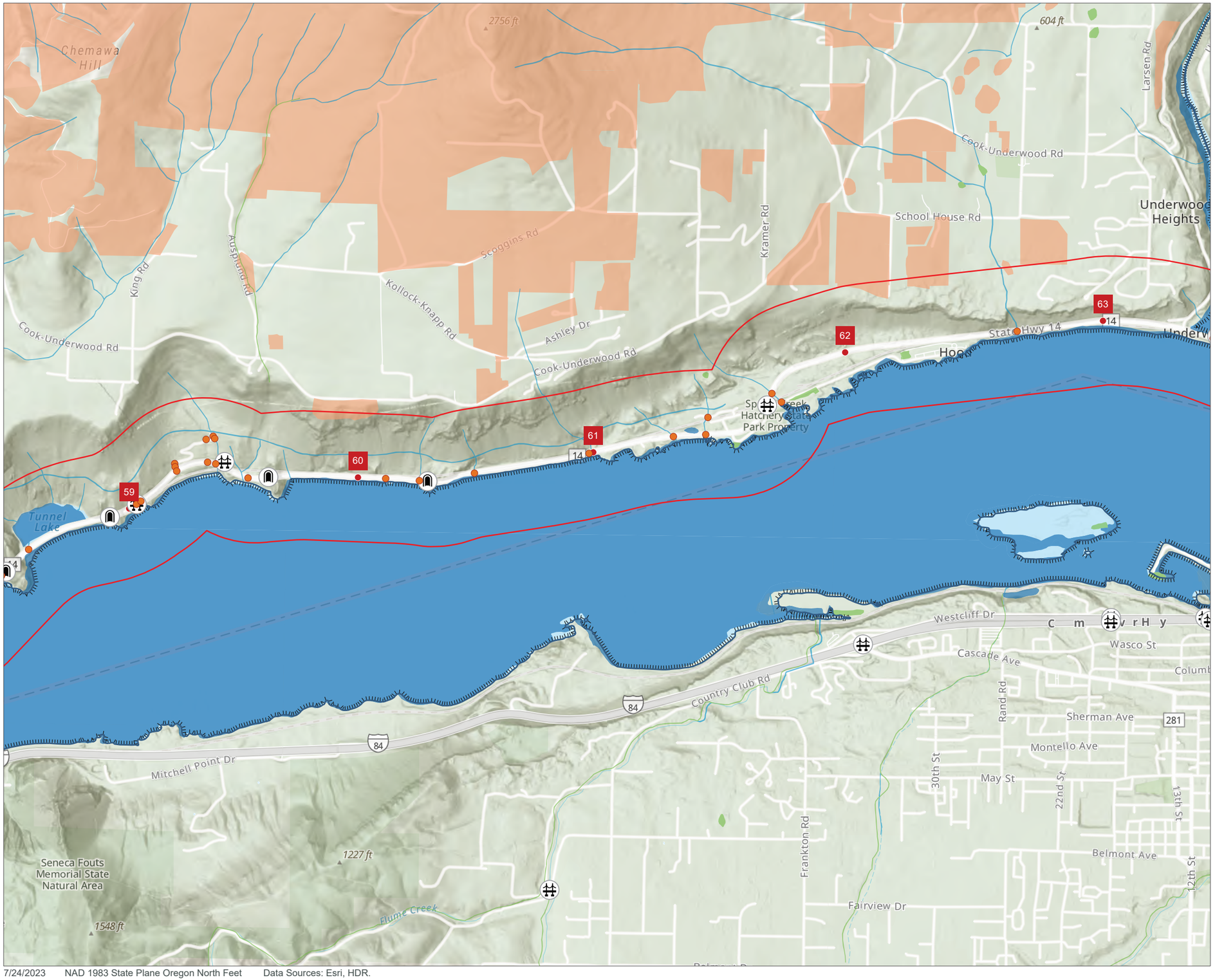

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- MARSH, SWAMP, BOG, PRAIRIE
- RIVER
- LAKE, RESERVOIR

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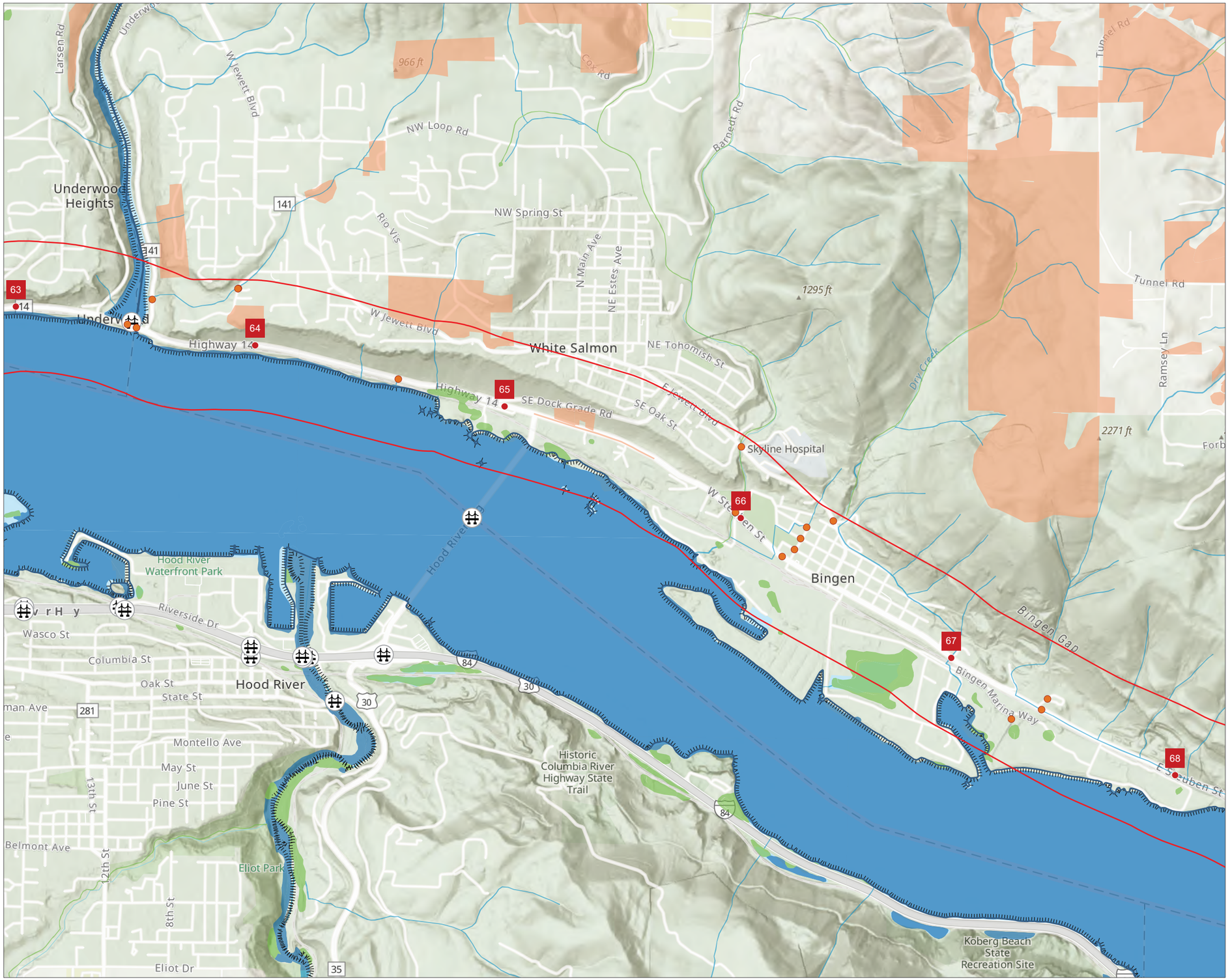

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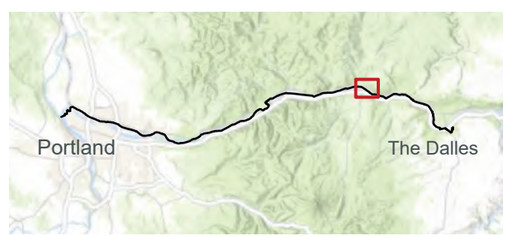

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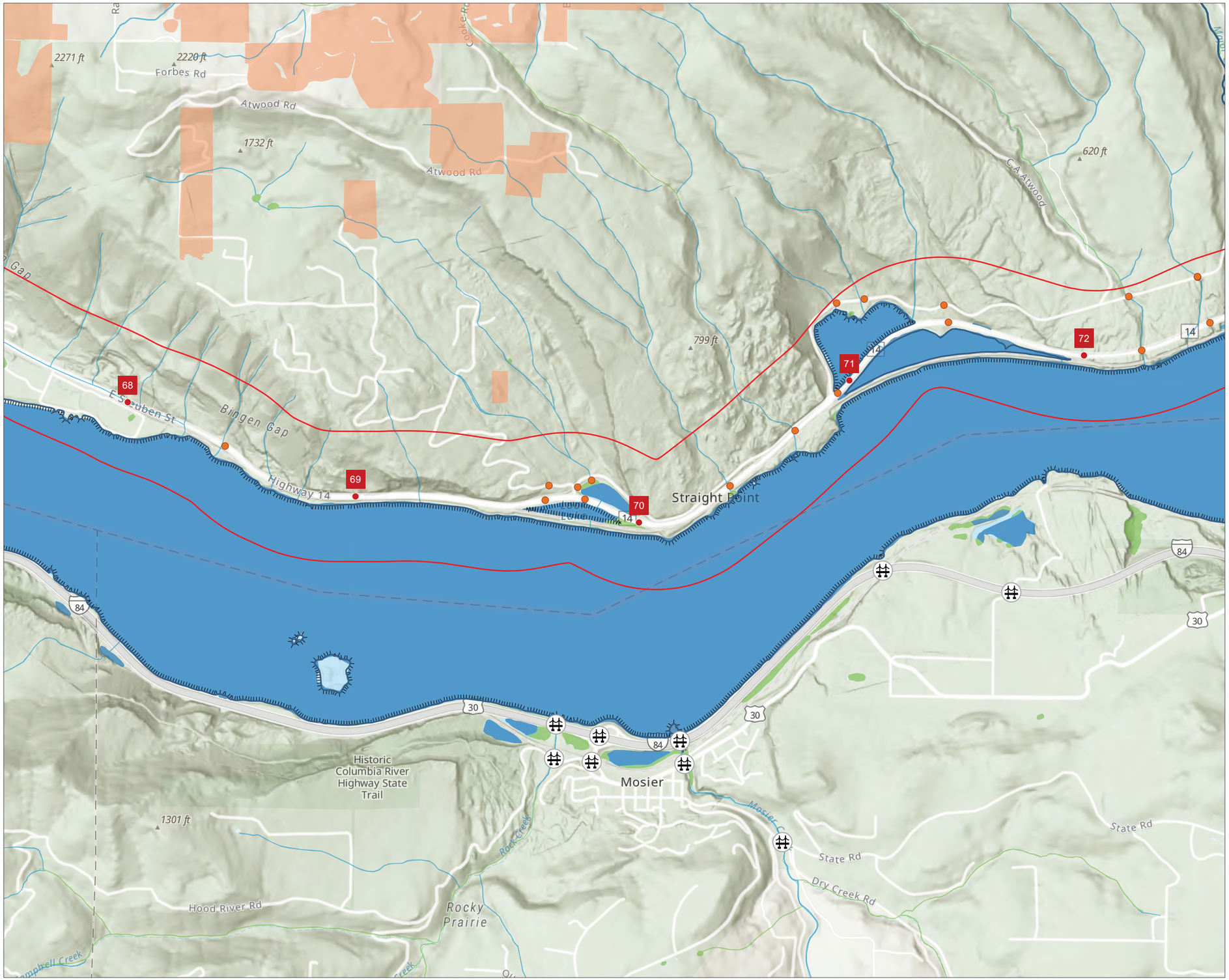

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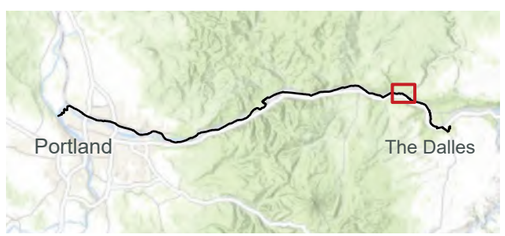

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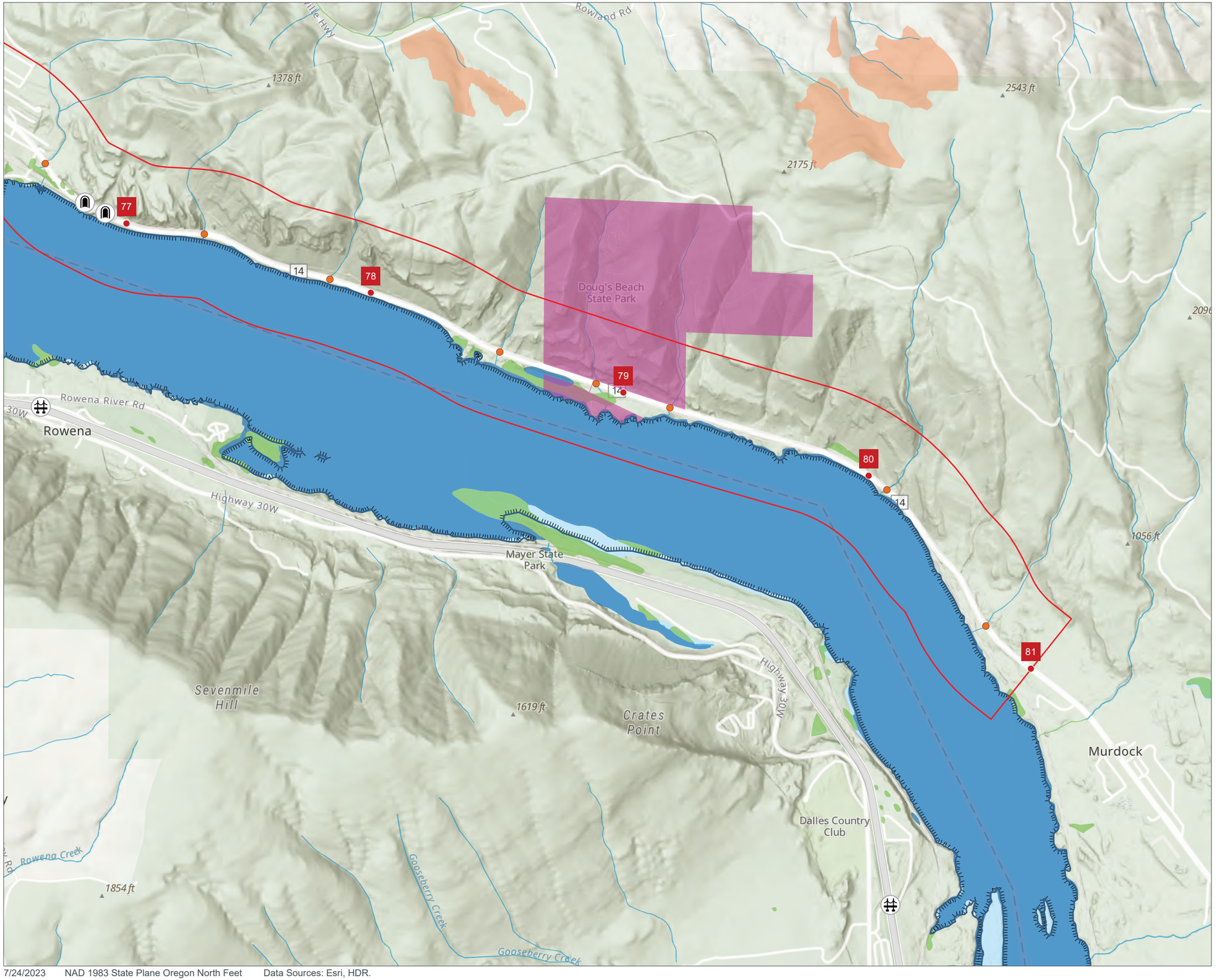

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CASCADE RENEWABLE TRANSMISSION

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4.0 Summary

The objective of the CRT project is to address state mandates calling for decarbonization as early as 2030. The regulatory and construction requirements to protect environmental resources, cultural resources, and highway users associated with the SR-14 project route would result in significant or permanent delays to the project schedule such that the objective of the CRT project could not be met by the target year. Further, assuming all regulatory requirements were addressed in a timely manner and the SR-14 project route were moved forward to construction, it is highly unlikely that a contractor would be willing to construct a project with the magnitude of the above-mentioned constraints. The culmination of the significant challenges along a majority of the SR-14 project route would precipitate a non-constructable and infeasible CRT project.

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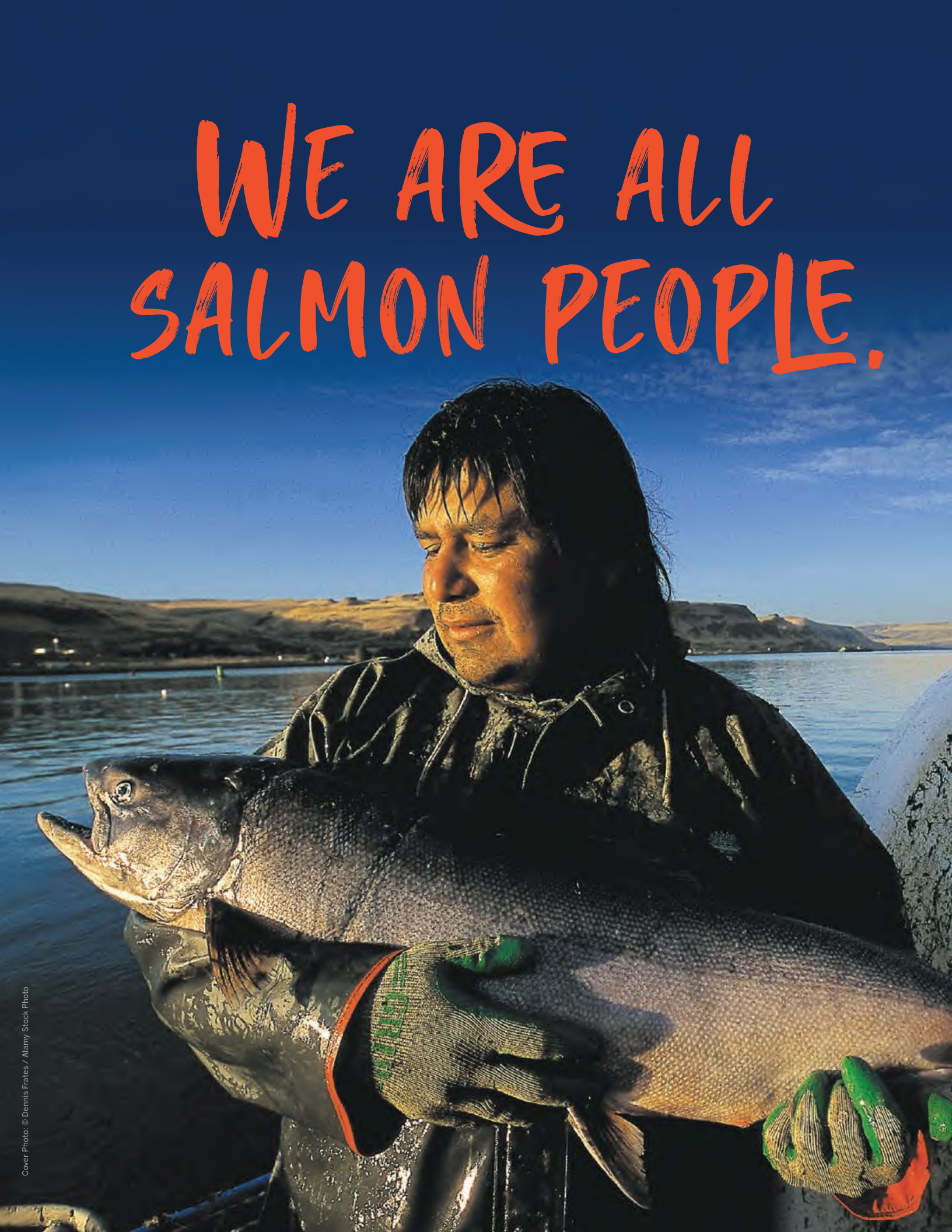
Attachment 17. CRITFC Energy Vision for the Columbia River Basin

ENERGY VISION

for the Columbia River Basin

Columbia River Inter-Tribal
Fish Commission

WE ARE ALL SALMON PEOPLE.



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Columbia River Inter-Tribal Fish Commission

PREFACE

The **Columbia River Inter-Tribal Fish Commission (CRITFC)** was created by the Nez Perce, Umatilla, Warm Springs, and Yakama tribes in 1977. CRITFC provides technical support, policy coordination, and enforcement services to the four tribes. More than 40 years ago, CRITFC assisted its member tribes in developing the provisions for the Northwest Power Acts energy planning and fish and wildlife requirements. Since then, it has supported its member tribes' goals for improving the conditions of the Columbia Basin's anadromous fish populations.

Recent dramatic changes in Columbia Basin salmon populations and the West Coast energy planning environment prompted CRITFC to undertake this second major revision of its energy-related recommendations intended to protect the tribes' treaty-secured fish, wildlife, cultural and other resources. I would like to express my appreciation to the Commission, which remained engaged with staff in development of this Vision document.

CRITFC received comments from more than thirty reviewers on the draft it released June 30, 2021. Commenters made many helpful suggestions for the final, including requests for:

- Recognition of broad tribal support for restoring healthy and harvestable salmon populations;
- Expanded energy efficiency for the region;
- Additional detail on future hydro configurations and operations;
- Analysis of Snake River dam breaching;
- Siting transmission and renewable resources; and
- Modernizing the Columbia River Treaty.

Looking forward, we appreciate the engagement of other sovereigns in the region and their desire to collaborate in the implementation of many recommendations contained in the 2022 Energy Vision. Making the recommendations in this Energy Vision a reality will take collaboration and hard work.

Sincerely,

Aja K. DeCoteau
Executive Director

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"It took us two centuries to destroy this land. It's going to take longer than that to fix it back up. So I'm saying that you are the land. We are the land. What is done to the earth is done to ourselves. So I would hope that you become my allies."

— Louie Dick, Warm Springs, 1994

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The Pacific Northwest Is Facing Four Critical Issues.

Many Columbia Basin **salmon and steelhead populations are near extinction.**

The climate crisis is already underway; without strong action, it will further reduce the survival of salmon and steelhead and damage every part of the region's economy and environment.

Renewable resources will play a larger role in meeting future electricity needs in the region. Under the right conditions they can reduce greenhouse gases and benefit salmon.

Without proper integration and siting, **renewable resources can make things worse for Columbia River salmon** and other tribal resources.

A major theme of this Energy Vision is to ensure that renewable resources in combination with increased storage, reductions in peak demand, and increased energy efficiency can provide clean, adequate, reliable, and affordable electricity, support the restoration of healthy, harvestable salmon populations, and prevent future damage to salmon and steelhead and other tribal resources caused by the electrical system.

Vision for Columbia River Resources and Energy

CRITFC and its member tribes envision a future where the Columbia Basin electric power system supports healthy and harvestable fish and wildlife populations, protects tribal treaty and cultural resources, and provides clean, reliable, and affordable electricity.

The goals for this Energy Vision are:

- **Create a regional energy portfolio** that protects and enhances environmental quality, treaty protected resources, and supports the restoration of Columbia Basin's fish and wildlife to healthy and harvestable population levels.
- **Prevent new and reduce ongoing damage** to Columbia River Basin resources, including fish, wildlife, water quality, and tribal cultural resources, by recognizing the relationships and interdependencies of natural and built systems including the Northwest's energy system.
- **Provide increased protection** for both fish and wildlife and utility customers against unanticipated events, such as drought, fire, and market aberrations while providing an adequate, economical, and reliable electric supply.
- **Mitigate climate change impacts** to protect Northwest ecosystems by replacing fossil-fuel electric generation and reducing the reliance on fossil-fuels for power, transportation, and other uses.

The Yakama, Nez Perce, Umatilla, and Warm Springs tribes founded CRITFC in 1977 to protect their treaty rights to take salmon and other resources. In 1855, each of the four tribes entered a separate treaty with the United States which ceded title to vast amounts of land in the interior Columbia Basin while reserving rights to take fish and gather First Foods.

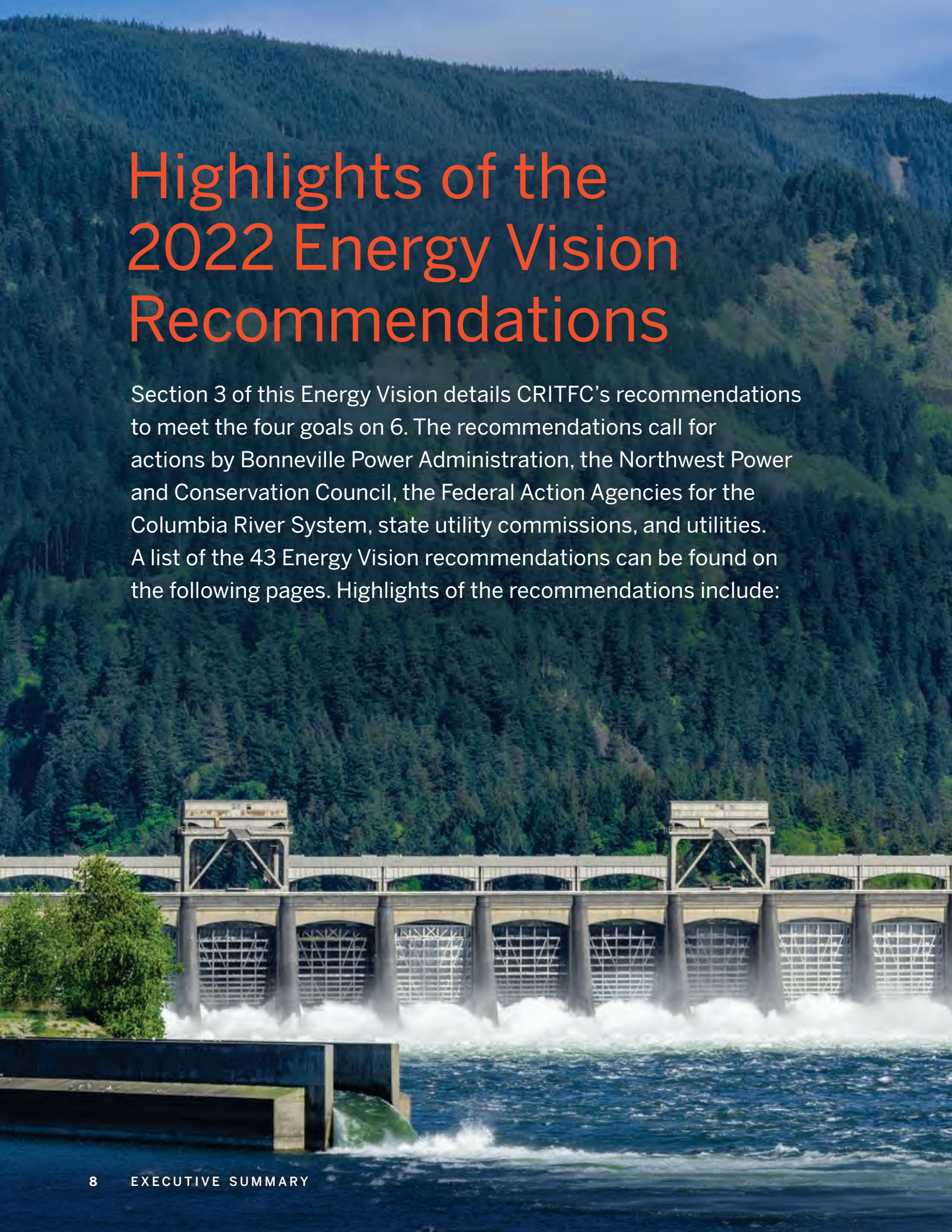
In May 2021, a coalition of 57 tribes from the Pacific Northwest adopted a resolution calling on Congress and the President to *"Invest in Salmon and River Restoration in the Pacific Northwest, Charting a Stronger, Better Future for the Northwest, And Bringing Long-Ignored Tribal Justice To Our Peoples And Homelands."* Affiliated Tribes of Northwest Indians, Resolution #2021–23 adopted at the 2021 Mid-Year Convention. Recognizing that the fate of the tribes and Northwest salmon are intertwined, the resolution called for implementing bold energy and salmon actions including "restoring the lower Snake River by breaching the four lower Snake River dams." The resolution also recognizes that "offering a solution that invests in a stronger, better Northwest that goes beyond salmon, ensuring that communities impacted by river restoration are made whole—and in doing so offering additional opportunities for tribes within other sectors—from infrastructure and technology development to energy production." A substantially similar resolution was adopted by the National Congress of American Indians in June 2021. NCAI is the oldest and largest national organization representing American Indian and Alaska Native tribal governments. These resolutions are set forth in APPENDIX B.

"The salmon was put here by the Creator for our use as part of the cycle of life. It gave to us, and we, in turn, gave back to it through our ceremonies."

— Carla HighEagle, Nez Perce, 1999

Highlights of the 2022 Energy Vision Recommendations

Section 3 of this Energy Vision details CRITFC's recommendations to meet the four goals on 6. The recommendations call for actions by Bonneville Power Administration, the Northwest Power and Conservation Council, the Federal Action Agencies for the Columbia River System, state utility commissions, and utilities. A list of the 43 Energy Vision recommendations can be found on the following pages. Highlights of the recommendations include:



Improve River Configuration and Operations

The region needs to plan for changes to reduce the damage to migrating salmon and steelhead caused by the Columbia Basin dams, including breaching the four lower Snake River dams.

Amend the Columbia River Treaty

Amend the treaty to include protections for fish and wildlife and expand the scope to include win-win opportunities to integrate renewable resources.

Reduce Peak Loads

Reduce peak demands to save both salmon and money.

Maximize Energy Efficiency

Maintain and expand energy efficiency targets and work to exceed them. Energy efficiency measures are positive for fish and wildlife.

Harness Renewable Resources

Renewable resources in combination with storage and electric load management can create an environment that is better for fish and wildlife and other tribal resources.

Strategically Site Renewable Resources

Develop a regional plan for where renewable resources should be developed and where they should not, and to provide expeditious siting with clear and uniform standards across all political subdivisions.

Increase Resource Adequacy

Prevent electricity shortages, which can reduce protection and funding for fish and wildlife.

Minimize Transmission and Distribution Systems

Load management, energy efficiency, and strategic siting of resources will reduce costs for consumers and the damage to tribal resources.

Address the Climate Crisis

Reduce greenhouse gas pollution and continue to increase energy efficiency to try to avoid the devastating effects we are facing.

2022 Energy Vision Full Recommendations

Following are the 43 recommendations CRITFC has identified in this Energy Vision to help achieve our vision of a Columbia Basin electric power system that supports abundant and sustainable fish and wildlife populations, protects tribal treaty and cultural resources, and provides clean, reliable, and affordable electricity. CRITFC will monitor the implementation of these recommendations and prepare a report in five years to evaluate whether and how the recommendations have been implemented.

River Restoration and Improved Dam Configurations and Operations

Recommendation 1: The region should prepare to implement river restoration, dam configurations, and river operations that are compatible with, and support, healthy and harvestable fish populations. These recommendations include breaching the four lower Snake River dams, spill operations at run-of-river dams, flow related operations at storage dams, structural modifications to aid salmon and lamprey passage, needed maintenance, flood control studies, actions to improve water temperatures, and capability for lower Snake River dam breaching.

Amend the Columbia River Treaty

Recommendation 2: The United States and Canada should include direct participation of the 15 tribal sovereigns in the U.S. portion of the Columbia Basin in negotiations to modernize the Columbia River Treaty in ways that restore and maintain ecosystem functions compatible with healthy and harvestable treaty-protected resources. The parties should integrate other energy resources into the treaty negotiations that have the potential to reduce carbon emissions and improve renewable resource integration while protecting fish impacted by the energy systems of the two countries

Recommendation 3: The Corps of Engineers should conduct a comprehensive study of flood risk in the Columbia Basin and the need to make regional decisions on balancing flood risk with multiple purposes of the system, including ecosystem function and effects on fish and wildlife.

Reduce Peak Loads

Recommendation 4: The Council, BPA, and utilities should include the peak savings and reductions in transmission and distribution benefits in calculating the capacity value of energy efficiency programs.

Recommendation 5: Northwest public utility commissions should implement time-of-use rates to send an appropriate price signal that captures the dramatically different costs of using electricity during different times of the day.

Recommendation 6: Utilities should use demand response to manage system loads, reducing peak loads, ensuring reliability by encouraging customers to reduce demand during peak periods, or shift loads from peak to off-peak hours.

Recommendation 7: Automobile manufactures should include systems that allow electric vehicles to schedule charging during off-peak periods.

Recommendation 8: Utilities should integrate electric vehicle charging and batteries into the power system to reduce costs to consumers and the power system and improve salmon migration.

Recommendation 9: BPA and utilities should work to improve the efficiency of electric vehicles.

Recommendation 10: The Council, BPA, and utilities should fund the incremental costs of heat pump water heaters to stimulate the adoption of this technology.

Recommendation 11: Utilities and BPA should develop and fund programs to schedule when water heaters operate.

Increase Electricity Storage

Recommendation 12: BPA and utilities should implement utility-scale battery projects.

Recommendation 13: BPA and utilities should implement incentive programs to expand the use of on-site batteries.

Recommendation 14: BPA and utilities should fund programs to reduce peak loads using the thermal mass of buildings.

Recommendation 15: The Council and utilities should not pursue potential pumped storage sites unless they are consistent with the siting criteria.

Recommendation 16: Utilities and the Council should continue to monitor green hydrogen technologies.

Maximize Energy Efficiency

Recommendation 17: The Council should increase the conservation targets in the 8th Power Plan to maintain at least the level of activity called for in the 7th Plan and work with BPA and utilities to try to exceed the targets.

Recommendation 18: The Council should monitor the implementation of energy efficiency programs to ensure that utilities meet the conservation targets.

Recommendation 19: All tribal homes and businesses should be fully weatherized by 2025 and all tribal homes and businesses should receive solar panels and battery systems that provide zero net energy by 2030.

Recommendation 20: Utilities should weatherize and achieve net zero energy for all low-income homes by 2035.

Recommendation 21: Utilities, the Northwest Energy Efficiency Alliance, and other organizations should implement comprehensive programs to improve energy management practices in the commercial and industrial sectors.

Harness Renewable Resources and Integrate/Synergize with Electricity Storage

Recommendation 22: Congress, state legislatures, the Council, and public utility commissions should review programs to reduce greenhouse gases to avoid unintended consequences.

Recommendation 23: The Council should analyze the integration of renewable resources under a range of scenarios for river operations.

Recommendation 24: Utilities and BPA should continue to pursue wind development, and the associated efforts to integrate wind power, consistent with the tribal concerns and protections for fish, wildlife, and cultural resources.

Recommendation 25: The region should expand its efforts to promote utility-scale solar energy.

Recommendation 26: BPA and utilities should fund proof of concept projects for dual use solar.

Recommendation 27: States, local governments, and utilities should expand policies to promote on-site solar systems.

Recommendation 28: The Council, Northwest legislatures, energy regulators, and utilities should consider adopting zero net energy building standards.

Recommendation 29: State and local governments should adjust building codes to ensure that they can accommodate on-site batteries.

Recommendation 30: The Council, BPA, and utilities should continue to monitor and support other promising renewable resources.

Strategically Site Renewable Resources

Recommendation 31: CRITFC and its member tribes should work with state energy and siting agencies, federal agencies, Northwest Grid, the Northwest Power Pool, and others to develop a comprehensive plan for siting renewable resources and transmission lines that builds on efforts currently being developed in the states.

Increase Resource Adequacy

Recommendation 32: The Northwest Power Pool Resource Adequacy Program should address fish and wildlife protections.

Recommendation 33: The California Public Utilities Commission and the California Independent System Operator should address reliability issues in California that could affect the Northwest.

Recommendation 34: BPA and Congress should address repayments to the Treasury to avoid curtailment of fish and wildlife protections.

Recommendation 35: The Pacific Northwest utilities, states, and federal agencies should closely monitor West Coast energy market developments to ensure that they address impacts on Columbia Basin fish and wildlife and other tribal resources.

Minimize Transmission and Distribution Systems

Recommendation 36: BPA and utilities should invest in solutions that minimize transmission and distribution expansions.

Recommendation 37: BPA, utilities, and public utility commissions should develop a transparent system to report transmission and distribution costs.

Recommendation 38: BPA and utilities should address transmission reliability.

Address the Climate Crisis

Recommendation 39: Federal, state, and local policy makers should develop programs to reduce the use of fossil fuels.

Recommendation 40: Federal and state governments should end all subsidies for fossil fuels.

Recommendation 41: Utilities, tribes, farming, and non-governmental organizations should implement pilot projects to sequester carbon dioxide.

Additional Considerations

Recommendation 42: Northwest utilities should not consider new nuclear power missions at the Hanford Nuclear Reservation without tribal consultation and consent. Evaluation of other sites for nuclear fission should consider the costs and compatibility with intermittent renewable resources and salmon protections.

Recommendation 43: Utilities and Public Utility Commissions should adopt policy to deny service for cryptocurrency mining in the Northwest.

NEXT STEPS

Call for Action

The Northwest is at a critical crossroads, facing challenges to the health of the planet and the future of iconic fish and wildlife. These challenges are especially important to tribal resources that have sustained tribal people since time immemorial.

One path leads to affordable, carbon-free energy that harmonizes with the ecosystem. This future would prioritize energy efficiency, renewable resources, new storage technologies, reductions in peak loads, and other strategies that are compatible with the needs of fish and wildlife. These efforts would reduce the impacts of renewable resource projects and transmission lines on tribal resources and save consumers money.

The other path creates conflicts between renewable resources and tribal resources and results in higher costs for consumers.

Choosing the first path will require courage to act, common-ground solutions, and a commitment of resources to accomplish the hard work ahead. It will also require the humility to periodically evaluate and adjust course based on new information and understanding.

CRITFC and its member tribes are committed to working with other regional interests to lead the region to a brighter and healthier future. Affordable and reliable power is important to regional families and businesses, tribal and non-tribal. The true wealth of our region begins with the health of our rivers, fish, and the ecosystem they support, which is our culture, history, and future.

"By working together, it is my hope that we not only retain and enhance what we have, but also provide resiliency in all our tribal foods and cultural needs into the future. In working to provide for our people and our futures, we honor the sacrifices and dedication of our elders and ancestors."

— Quincy Ellenwood, Nez Perce, 2021

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1 Introduction and Prologue

1.1 Introduction: Visions of the Columbia River Basin

The Pacific Northwest is facing four critical issues.

- Many Columbia Basin salmon and steelhead populations are near extinction.
- The climate crisis is already underway; without strong action, it will further reduce the survival of salmon and steelhead and damage every part of the region's economy and environment.
- Renewable resources will play a larger role in meeting future electricity needs. Under the right conditions they can reduce greenhouse gases and benefit salmon.
- Renewable resources must be properly integrated and sited to improve conditions for Columbia River salmon and other tribal resources.

The first Tribal Energy Vision in 2003 included recommendations to avoid another energy shortage that damaged fish and wildlife and the economy. In 2001, a drought—in combination with the Bonneville Power Administration's (BPA) commitment to serve more power than it could generate and the electric industry manipulation of the California energy market—resulted in a power shortage. These energy problems cost BPA's consumers four billion dollars and resulted in BPA eliminating protection measures for salmon migrating through the dams and cutting funding for fish and wildlife restoration programs.

The 2001 river actions resulted in significant losses of juvenile salmon. In 2001, just 6% of juvenile steelhead survived their in-river migration from Lower Granite Dam on the Snake River to Bonneville Dam; in most years the survival rate is 40% to 70%. This resulted in significant and lasting economic impact to tribal fishermen.

Steelhead Salmon

Chinook Salmon

The second Energy Vision in 2013 focused on reducing hydroelectric dam impacts on salmon populations and decreasing costs for consumers. It included strategies to reduce peak demands, which harm salmon and cost consumers hundreds of millions of dollars to operate expensive resources and expand transmission and distribution systems. It also identified additional energy efficiency actions that could save hundreds of millions of dollars. APPENDIX A provides more background on these prior Energy Visions.

The 2022 Energy Vision is driven by the salmon and steelhead crisis. The populations of Columbia and Snake River salmon and steelhead are at very dangerous levels for their continued existence.

- Twelve of 31 populations (nearly 38%) of Snake River spring/summer Chinook have fewer than 50 wild-origin fish and are at high risk of extinction; Upper Columbia Spring Chinook and Steelhead are at critically low levels. By 2025, a total of 24 (77%) populations are predicted to be at or below 50 wild spawners.
- A recent stay of litigation addressed river operations through July of 2022. Additional ongoing processes will address near-term and long-term modifications in the configuration and operation of the Columbia Basin dams. The energy system needs to be prepared to address and incorporate these fish and wildlife needs.
- The NPCC's 8th Power Plan modelling assumes that the hydro system will serve as the primary battery back-up for increasing solar and wind generation; effectively bringing Columbia River flow to a halt during the peak of salmon migration.

This Energy Vision also comes at a time of extraordinary changes in the electric energy system and its related environment.

- Climate change has created drought, fires and other changes affecting river operations and transmission.[1]
- Several states have enacted standards and policies to reduce greenhouse gas pollution which will change the mix of resources and increase electricity demands.
- Tribes across the nation have recognized the impacts of the Columbia River Basin's dams on the tribes of the Northwest and are calling for bold actions for restoring salmon including breaching the four lower Snake River dams.
- The new Administration, the 117th Congress and the Pacific Northwest have extraordinary opportunities to secure federal authorities and funding to implement these bold actions, and to invest in salmon recovery, river restoration and energy security throughout the region.
- Coal plants are phasing out.
- Some utilities are concerned about whether there will be adequate electricity supplies.
- Dramatic reductions in costs for renewable technologies and batteries have led to significant increases in solar and wind energy generation and storage abilities, which results in dramatic operational changes in overall generation patterns.

[1] Climate change is expected to exacerbate the currently unhealthy river temperatures in the Snake and Columbia Rivers, where relatively slow-moving water is warmed by the broad areas of the reservoir surfaces exposed to solar radiation.

- Costs have also come down for storage batteries, which can integrate intermittent renewable resources, so the power is available when it is needed.
- Energy efficiency has improved, but the Northwest Power and Conservation Council (Council or NPCC)[2] is considering reducing targets in future years.
- Increased electric transportation will require management of charging to assure environmental impacts are positive for salmon.
- Renewable energy must be appropriately priced to ensure that major changes in the west coast energy market do not damage salmon as low-cost solar power reduces river flows during the day and the dams create large flow fluctuations to serve morning and evening peak loads.

A major theme of this Energy Vision is to ensure that renewable resources in combination with increased storage, reductions in peak demand, and increased energy efficiency can provide clean, adequate, reliable, and affordable electricity and support the restoration of healthy and harvestable salmon and steelhead populations and other tribal resources caused by the electrical system. Additional energy efficiency actions and strategies to reduce the need for new transmission and distribution lines should save consumers hundreds of millions of dollars per year. However, renewable resources must be properly integrated and carefully cited to ensure the future will be better for Columbia River salmon and other tribal resources.

1.2 Vision for Columbia River Resources and Energy

CRITFC and its member tribes envision a future where the Columbia Basin electric power system supports abundant and sustainable fish and wildlife populations, protects tribal cultural resources, and provides clean, reliable, and affordable electricity.

The goals for this Energy Vision are:

- **Create a regional energy portfolio** that protects and enhances environmental quality, treaty protected resources, and restores healthy fish and wildlife populations in the Columbia Basin.
- **Prevent new and reduce ongoing damage to Columbia River Basin resources,** including fish, wildlife, water quality, and tribal cultural resources, by recognizing the relationships and interdependencies of natural and built systems including the Northwest's energy system.
- **Provide increased protection for both fish and wildlife and utility customers against unanticipated events,** such as drought, fire and market aberrations while providing an adequate, economical, and reliable electric supply.
- **Restore the lower Snake to a climate resilient free-flowing river** and mitigate climate change impacts to protect Northwest

[2] The Northwest Power and Conservation Council was created by Congress and the states of Idaho, Montana, Oregon and Washington to provide planning and policy leadership on regional electric power and fish and wildlife issues. The Council develops a [power] plan, which, if implemented, will assure the region of a safe, reliable, and economical power system with due regard for the environment. The Council also prepares a [fish and wildlife] program to protect, enhance, and mitigate fish and wildlife affected by the Columbia River hydroelectric system. NPCC Bylaws, Chapter 2, https://www.nwcouncil.org/about/bylaws.

ecosystems by replacing fossil-fuel electric generation and reducing the reliance on fossil-fuels for power, transportation, and other uses.

In 1977, four sovereign treaty tribes of the Columbia River Basin: the Yakama Nation, the Nez Perce Tribe, the Confederated Tribes of the Umatilla Indian Reservation, the Confederated Tribes of the Warm Springs Reservation of Oregon, formed CRITFC to provide coordination, management, and technical assistance to ensure that their treaty fishing rights are protected through the continuation and restoration of tribal fisheries into perpetuity. The four tribes wholly, indivisibly, and equally own and govern the affairs of CRITFC. Numerous federal court decisions have affirmed these treaty rights.[3]

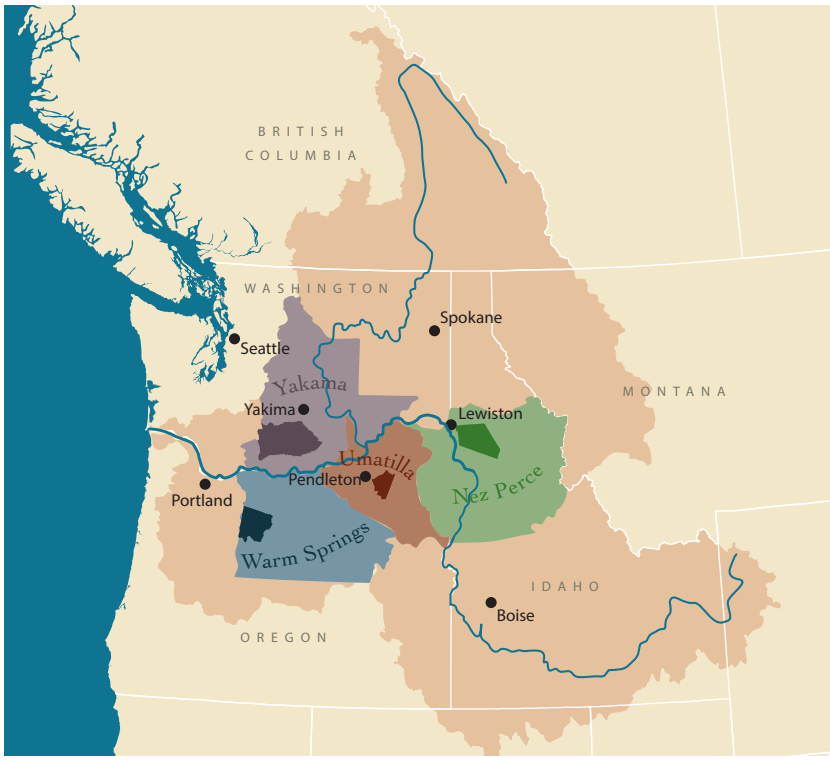
Tribes throughout the Northwest are united by salmon; by the Northwest rivers that salmon, steelhead, lamprey, and native fish depend upon; and by the interconnectedness of salmon with their ecosystems—from the orca in the ocean and Puget Sound to the nutrients which salmon supply to the furthest inland streams. All these tribal cultures and lifeways are rooted in place and tied to their homelands. Tribes simply cannot relocate to access traditional resources.[4]

APPENDIX C describes the Federal Action Agency (BPA, the Bureau of Reclamation, and the Army Corps of Engineers) obligations to rebuild fish populations under the Northwest Power Act. APPENDIX H provides a discussion of environmental management and First Foods.[5]

FIGURE 1 shows the Columbia River Basin in light brown. The ceded areas of the Yakama, Nez Perce, Umatilla, and Warm Springs tribes are shown in purple, green, brown, and blue with the current reservations in darker shades.

For the tribes and CRITFC to accomplish their mission, salmon, Pacific lamprey, and mussel populations need to be rebuilt. The dams on the Columbia and Snake rivers continue to be the main obstacles to anadromous fish restoration.

FIGURE 1. Reservations and Ceded Areas of the Yakama, Nez Perce, Umatilla, and Warm Springs Tribes



[3] For more information on the treaties, see https://www.critfc.org/wp-content/uploads/2021/11/Treaty-Rights-list.pdf.

[4] Please refer to the ATNI and NCAI resolutions referenced in footnote 1, *supra*, and set forth in APPENDIX B.

[5] Since time immemorial, the health, spirit, and cultures of the Columbia River tribes have been sustained by the water, salmon, game, roots, and berries of our homeland— our sacred "First Foods. See also *Quaempts, E. J., K. L. Jones, S. J. O'Daniel, T. J. Beechie, and G. C. Poole. 2018. Aligning environmental management with ecosystem resilience: a First Foods example from the Confederated Tribes of the Umatilla Indian Reservation, Oregon, USA. Ecology and Society 23(2):29.* https://doi.org/10.5751/ES-10080-230229.

Courtesy: NOAA Fisheries

1.3 Salmon and Steelhead Face Extinction

This update to the Energy Vision comes at a critical time because salmon and steelhead populations in the Columbia and Snake rivers are in a dire condition.

- Twelve populations of salmon and steelhead are listed as either threatened or endangered under the Endangered Species Act.
- Currently, 42% of Snake River spring/summer Chinook populations have fewer than 50 wild-origin fish. Populations this low are near extinction. By 2025, 77% of these Snake River Chinook populations are predicted to have of less than 50 wild-origin fish and be near extinction.
- Three stocks triggered NOAA's 2014 BiOp early warning and significant decline indicators: Upper Columbia Spring Chinook, Upper Columbia Steelhead, and Snake River Steelhead.
- The total abundance of salmon and steelhead in the Columbia River is at or near levels when the first Endangered Species Act (ESA) listings were registered in the mid-1990s.

Since 1987, the Council's interim goal for the Columbia River Basin Fish and Wildlife Program is to "Increase total adult salmon and steelhead runs of Columbia River origin to a 10-year rolling average of five million annually by 2025, in a manner that emphasizes increases in the abundance of the populations that originate above Bonneville Dam." Salmon and steelhead populations have averaged about one million fish over the past five years—we are nowhere close to achieving the year 2025 Program goal. More recently, the Columbia Basin Partnership based its recommendations to NOAA Fisheries on a "strong sense of urgency that immediate action is needed to address salmon and steelhead declines in the Columbia River Basin." Their Phase 2 report finalizes qualitative and quantitative goals for all salmon and steelhead, both ESA-listed and non-listed, and provides recommendations for continuing collaboration going forward.[6]

The tribes have developed recommendations for near-term and longer-term river configuration and operation actions to improve fish and wildlife survival. CRITFC has summarized many of these recommendations in SECTION 3.1 and APPENDIX C. These actions are being pursued in various decision processes.

[6] MAFAC's Columbia Basin Partnership Task Force hosted by NOAA Fisheries was initially convened in 2017. The CBP task force completed in Phase 1 report in 2018 setting forth a "Vision for Salmon and Steelhead." https://media.fisheries.noaa.gov/dam-migration/mafac_report_cbp_phase_1_recommendations_full_report.pdf. The full Phase 2 report completed in 2020 reflects years of efforts with input from a broad range of representatives including utilities, states, tribes, ports, irrigation districts and non-governmental organizations. https://s3.amazonaws.com/media.fisheries.noaa.gov/2020-10/MAFAC_CRB_Phase2ReportFinal_508.pdf?null.

1.4 Changes in the Electrical System Can Help or Hurt Salmon

Climate Crisis. Several states and utilities have adopted unprecedented plans to reduce greenhouse gases, and the federal government has adopted and is considering several programs that would reduce these pollutants as part of the Infrastructure Investment and Jobs Act and Build Back Better legislation. Renewable resources and battery storage in combination with energy efficiency can help the Northwest address the climate crisis that is already damaging salmon, steelhead, and other tribal resources. It is critical to reduce greenhouse gas pollution and continue to increase energy efficiency to try to reduce the devastating effects that salmon are facing.

Renewable Resources. The costs of renewable resources have declined dramatically, and these resources will be the major source of energy in the future. According to the Council, wind and solar currently supply about 10,000 MW of capacity in the Northwest. The Council's draft 8th Power Plan[7] recommends that the region add 3,500 megawatts of solar and wind projects by 2027, growing to 14,000 additional megawatts by 2041. Battery storage capacity is rapidly increasing, with its cost decreasing. Renewable resources in combination with storage and reductions in peak demand can ultimately improve conditions for fish and wildlife and other tribal resources.

New renewable resources must be properly sited to avoid impacts from construction and operation of these resources. Large industrial scale solar and wind projects have displaced tribal people from access to their traditional foods. Terrestrial and land-based cultural resources are at risk from transmission construction and annual vegetation management operations.

New renewable resources can and should be paired with battery storage and must be wisely integrated to make the environment better for Columbia River salmon. Solar provides energy during daylight hours and wind energy production can vary during the day. Integrating electric energy production and battery storage is complex; supplies must be matched with the changing needs every minute of the 8,760 hours in every year. However, the Columbia Basin's hydro system is in an ecosystem and has profoundly and detrimentally impacted the biological resources dependent on that ecosystem. Adding more burdens to that ecosystem through increasing over-reliance on hydro resources to integrate renewable energy sources would be irresponsible and with adequate planning is not necessary to provide reliable and affordable clean power.

Columbia Basin hydro system configuration and operation have changed and will change in the future. Recently, plaintiffs and defendant agencies of the United States in the long-running ESA litigation, *NWF v. NMFS*, filed a stay of litigation through July 31, 2022, to increase

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[7] The Northwest Power and Conservation Council develops a new Power Plan every 5 years. At time of writing of this Energy Vision, the NPCC was in the process of developing their eighth Power Plan and had released the *Draft 2021 Northwest Power Plan in the fall of 2021*, available at https://www.nwcouncil.org/sites/default/files/2021powerplan_2021-5.pdf. The final 2021 Northwest Power Plan was released during publication of this Energy Vision document and can be found at https://www.nwcouncil.org/reports/2022-3/. This Energy Vision refers to the draft document available at the time of writing.

spill for juvenile fish passage, limit "zero flow" operations, and maintain reservoirs at minimum operating pools to benefit salmon migration. At the same time, Senator Patty Murray and Governor Jay Inslee of Washington announced their intention to complete recommendations in the same timeframe to address replacing the power and other services provided by the four lower Snake River dams if they are breached.

To assume that the current configuration and "flexibility" of the Columbia and Snake River hydropower system allows for full integration of solar and wind energy overlooks and conflicts with many resource concerns. Assigning zero costs for this "flexibility" is contrary to the intent of the Northwest Power Act's to prioritize environmental quality and protection of fishery resources. Hydro flexibility has imposed significant "costs" to salmon and steelhead populations and other tribal resources.

Peak Loads. Electric energy use spikes to high levels in the morning and late afternoon. Serving these peak loads causes fluctuations in river flows that hurt migrating salmon and steelhead. Meeting these peaks is expensive. Utilities operate their most expensive resources during these periods. We estimate utilities and BPA will spend more than eight billion dollars over the next five years to expand their transmission and delivery lines, a significant amount of which is driven to meet peak uses. This Energy Vision details actions to reduce peak demands that can save salmon and money. See SECTION 3 and supporting analysis in APPENDIX E.

Renewable Resource Siting. The projected growth in renewable resources could affect tribal First Foods, wildlife, and other tribal cultural resources. The Washington Department of Fish and Wildlife reports that there are currently 30 industrial solar projects proposed for Washington with a footprint of 49,000 acres, or nearly 77 square miles. The Oregon Department of Energy (ODOE) reports that the state Energy Facility Siting Council has approved seven projects and has seven more under review. The 14 projects cover 27,969 acres or 44 square miles. Local siting processes in Oregon would likely add to this total. Other states are facing similar development.

CRITFC recommends that federal, state, and tribal governments work together on a regional plan for locating renewable resources and providing expeditious siting with clear and uniform standards across all political subdivisions. This effort could build on the 2013 criteria developed by the Department of the Interior for renewable resource development and the Council's Protected Areas for new hydroelectric dams. SECTION 3 and APPENDIX F provides a sample of criteria that could be considered in this process. APPENDICES G and H describe cultural resource and First Foods concerns.

Energy Efficiency. Energy conservation and efficiency improvements are inherently fish and wildlife friendly. They require no "steel in the

ground" in undisturbed landscapes and will not impact tribal cultural resources. They operate 24-7, and unlike wind and solar energy resources they are generally not subject to variations in weather. Unlike thermal resources they are immune from fuel price increases. Properly developed energy efficiency and conservation can benefit low-income populations including tribal peoples.

Energy efficiency programs reduce both peak demands and year-round energy needs. Energy efficiency has been proven as a reliable resource in the Northwest and has saved consumers over $70 billion. These programs have reduced the emissions of pollutants that cause climate change by an estimated 240 million metric tons. Energy efficiency also reduces the region's seasonal storage needs because the energy savings closely track energy demand. The "flexibility" of energy efficiency is extremely valuable. These programs currently employ 100,000 people in the region.

The Council has significantly reduced the energy efficiency targets in its draft 8th Power Plan, primarily because of the low cost of solar and wind energy. The Council's current models and analysis may not be able to accurately reflect the role of energy efficiency in a transformed energy market that also protects fish populations. We are concerned that without updated and reliable modeling that better addresses the role of energy efficiency, the region will regret any reduction in this valuable resource that has proven to be compatible with the river's ecosystems.

SECTIONS 2 and 3 address all these issues in more detail.

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1.5 Summary of the Energy Vision Recommendations

SECTION 3 describes CRITFC's recommendations to create a future where the Columbia Basin electric power system supports abundant and sustainable fish and wildlife populations, protects tribal cultural resources, and provides clean, reliable, and affordable electricity.

- SECTION 3.1 details the planning needed to address future changes in the configuration and operation of the hydroelectric system to reduce the damage to migrating salmon and steelhead, including breaching the four lower Snake River dams.
- SECTION 3.2 calls for a fresh look at the Columbia River Treaty and improved coordination of Canadian and U.S. hydroelectric and flood control operations in recognition of the major changes in the economics and availability of other renewable resources.
- SECTION 3.3 describes actions to reduce peak electricity loads through energy efficiency, clear price signals, demand management, and storage.
- SECTION 3.4 addresses actions to secure all cost-effective energy efficiency, ensure that utilities achieve energy efficiency targets, expand low-income programs, and improve energy management practices in commercial and industrial buildings.
- SECTION 3.5 focuses on renewable resources, including actions to review and integrate greenhouse gas reduction policies, and actions to promote wind and solar generation, and other renewable resources.
- SECTION 3.6 calls for a comprehensive plan for siting renewable resources and transmission to focus development where it is appropriate, avoids sensitive areas, relieves congestion, and reduces the need for new transmission lines.
- SECTION 3.7 recommends additional actions, beyond those described above, to address resource adequacy, including increasing the Northwest Power Pool reserve standards.
- SECTION 3.8 identifies changes in BPA rate policies to protect fish and wildlife during low-water years.
- SECTION 3.9 addresses the need to monitor changes in the west coast energy market to ensure that they address impacts on Columbia Basin Fish and Wildlife and other tribal resources.
- SECTION 3.10 recommends actions that would reduce the need for new transmission and distribution lines that could save consumers hundreds of millions of dollars a year and reduce impacts on tribal resources.
- SECTION 3.11 calls for reducing reliance on fossil fuels and describes the tribes' opposition to transporting oil and coal through the region because of the dangers to fish and wildlife, cultural resources, and human health.
- SECTION 3.12 calls for pilot projects to sequester carbon dioxide.
- SECTION 3.13 describes opposition to siting new nuclear plants at the Hanford Nuclear Reservation and calls for studies of the compatibility of new smaller nuclear fission plants with intermittent renewable resources.
- SECTION 3.14 calls on utilities and utility commissions to deny service for cryptocurrency mining in the Northwest.

1.6
Tribal Leadership

The four CRITFC member tribes have applied the concepts found in the Energy Vision to their day-to-day government priorities. Their actions demonstrate leadership in reducing damage to salmon and other fish and wildlife in the Columbia Basin, reducing emissions causing climate change, and supporting a diverse and reliable energy resource mix that will lower energy costs and help recover abundant, harvestable salmon and other resident fish.

Significant changes in the environment, the energy industry, energy economics and markets, energy technologies, public awareness and government policy are bringing new opportunities for tribal energy actions. As described in **APPENDIX D**, tribes are frequently community and national policy leaders in employing ideas and technologies to solve environmental and natural resource problems. In particular, the existential environmental problem of climate change requires tribes to consider "energy" in many new ways. Environmental sustainability takes on broader and more critical meanings.

New federal legislation provides significant funding for energy efficiency and renewable resources and other actions to address the climate crisis. The Infrastructure Investment and Jobs Act nationally provides billions of dollars in energy resources support for smart grid programs, Energy Efficiency, housing weatherization, tribal climate reliance and many other measures. It will be important to structure these programs to benefit tribes.

Regionally, congressmen Simpson and Blumenauer are working on an initiative to help Columbia Basin salmon recover by restructuring mitigation policies and programs, breaching the four dams along the Lower Snake River and funding other restoration efforts.

Opportunities for Additional Tribal Leadership

- Tribes can legislate Tribal Energy Codes to create reservation goals, policies, procedures, funding, and programs to assure that the Energy Vision is implemented within the reservation.
- Tribes can apply for and appropriately manage funding from federal, state, local and private sources to meet goals and to improve application of new and cutting-edge technologies.
- Tribes can use their political leverage and longstanding cultural wisdom to influence public opinion and government policy.
- Tribes can lead by example.
- Tribes can develop partnerships with private institutions, educational bodies, local governments, utility and energy industry players, the Northwest Energy Coalition, the Bonneville Environmental Foundation, and others to further the Energy Vision and create buy-in by entities that may not otherwise be involved in improving the energy successes.
- Tribes can create local education programs for their own students and people and can work with outside educational entities to expand understanding of environmental/energy sustainability.
- Three of the four CRITFC Tribes are working to address the damages caused by the Hanford nuclear site.
- Inter-tribal organizations have a history of partnering with specific expert entities to address specific goals important to the organization.

1.7 Closing

This Energy Vision for the Columbia River Basin defines a set of recommendations that will allow for a healthier environment for fish resources and provide better protection against unforeseen events, such as drought or other extreme weather that affect the environment and energy systems.

The Nez Perce Tribe, the Confederated Tribes of the Umatilla Indian Reservation, the Confederated Tribes of the Warm Springs Reservation of Oregon, and the Confederated Tribes and Bands of the Yakama Nation, who make up the Columbia River Inter-Tribal Fish Commission (CRITFC), believe that river management need no longer be a fish versus power fight, where one side or the other is a winner or a loser. The region can enjoy an affordable, reliable energy system and have harvestable runs of salmon that support commercial, sport, and tribal harvests.

Our Energy Vision is economically and ecologically based to meet the requirements of fish and wildlife and the energy needs of the Northwest. The Energy Vision for the Columbia Basin highlights critical concerns with the region's existing energy system and sets forth a systematic approach to address these concerns. The Vision recognizes and supports the recommendations of tribes across the Pacific Northwest and the nation for restoring salmon and steelhead.

This vision outlines a set of resources that can be developed to meet future needs in a wise and cost-effective manner while reducing the region's energy dependency on the Columbia River hydroelectric system. The Energy Vision for the Columbia Basin continues to be a companion to CRITFC's *Wy-Kan-Ush-Mi Wa-Kish-Wit* (Spirit of the Salmon) Plan for Columbia River Anadromous Fish Restoration.

2 Major Changes for Salmon and Energy

2.1 The Columbia Basin Salmon Crisis

The 2013 Energy Vision focused on reducing the peaking at the Columbia and Snake River dams to improve fish and wildlife survival. The day-to-day and seasonal operations of the hydroelectric system to meet peak and seasonal electricity loads cause fluctuations in river levels that continue to kill salmon, resident fish, and other important fish species.

This update expands on this work and provides a more detailed description of the effects of the dams on tribal resources and recommendations for near-term and long-term actions (see SECTION 3.1 and APPENDIX C). It also focuses on the need to expand energy efficiency, energy storage, reductions in peak demand, and on-site solar to ensure that new renewable resources do not create problems for fish and wildlife. The condition of salmon and steelhead stocks in the Columbia Basin do not allow the region to assume that the federal hydro system is the only battery in town.

2.1.1. Salmon Populations are Continuing to Decline

The Columbia Basin is home to one of the richest arrays of salmon and steelhead in the world, and this wealth of anadromous species holds great ecological, cultural, spiritual, and economic value. But these resources are at risk. Protecting, restoring, and effectively managing these valuable species is one of the region's greatest responsibilities.

- Twelve salmon and steelhead populations in the Columbia Basin are listed as either threatened or endangered under the Endangered Species Act.
- The total abundance of salmon and steelhead in the Columbia River has not increased significantly since the first ESA listings were registered in the mid-1990s.

One of the recent federal salmon planning initiatives in the Basin encapsulates important context. NOAA Fisheries and its Marine Fisheries Advisory Committee (MAFAC) convened the Columbia Basin Partnership Task Force from 2017 through 2020 to bring together diverse representatives from across the Columbia Basin to establish a common vision and goals for salmon and steelhead. The Task Force considered impacts across salmon and steelhead life cycles (*e.g.,* habitat, harvest, hatchery, and hydro), and ecological conditions and current and future habitat capacity. The Task Force set Low, Medium, and High goals for 27 stocks of salmon and steelhead. Recent run sizes to the mouth of the Columbia River are nowhere near the High Goal or even the Low Goal. The populations of Columbia and Snake River salmon and steelhead are at very dangerous levels for their continued existence. The group determined that to address declines in salmon and steelhead, urgent and immediate actions need to be implemented.

As pointed out by NOAA Fisheries, Upper Columbia and Snake River salmon and steelhead populations are in dire condition.

- Three stocks have recently triggered their NOAA early warning and significant decline indicators: Upper Columbia Spring Chinook, Upper Columbia Steelhead, and Snake River Steelhead.
- NOAA's life cycle modelling of future climate scenarios for Snake River spring/summer Chinook salmon populations indicates that the median abundance of spring and summer-run Chinook salmon populations could further decline substantially in the next two to three decades, which would threaten to extirpate a large number of small populations.
- NOAA Fisheries' most recent Biological Opinion for Operations of the federal Columbia River System observed similar information:
  - **Snake River Spring/Summer Chinook Abundance**

    The adult abundance of Snake River spring/summer Chinook salmon indicate a substantial downward trend in the abundance of natural-origin spawners at the ESU level from 2014 to 2019. The three years from 2017 through 2019 have shown the lowest returns since 1999. The data also show recent and substantial downward trends in abundance of natural-origin and total spawners for most of the MPGs and populations when compared to the 2009 to 2013 period.
  - **Snake River Steelhead Abundance**

    The adult abundance of Snake River Bright steelhead also indicates a substantial downward trend in the abundance of natural-origin spawners at the DPS-level from 2014 to 2019.

- **Upper Columbia River Spring Chinook**

  The Entiat, Methow, and Okanogan River Spring Chinook populations remained at high overall extinction risk, while the Wenatchee River population status was considered "maintained" as of the most recent status review (NMFS 2016d). Overall, the ESU status remained unchanged from previous status reviews and was considered at high risk.

- **Upper Columbia River Steelhead**

  Data for these populations indicate a substantial downward trend in the number of natural-origin spawners at the DPS level from 2014 to 2019.

- In coordination with Idaho Fish and Game, Oregon Department of Fish and Wildlife, National Marine Fisheries Service and others, the Nez Perce Tribe's Department of Fisheries Resource Management in prepared an extensive review and forecast of salmon and steelhead population risks in the Snake River Basin. It concluded that currently, 42% of Snake River spring/summer Chinook populations have fewer than 50 wild-origin fish. By 2025, 77% of these Snake River chinook populations are predicted to hit their quasi-extinction risk threshold of less than 50 wild fish.[8] Additional material from this review is reported in **APPENDIX C**.

Too often, the federal government, regional utilities, and the NPCC assume that within hard-fought fish constraints the "flexibility" of the dams in the Columbia and Snake River basins can freely integrate solar, wind and other energy supplies into grid operations. In this fashion, economic dispatch models implicitly assign

zero costs for using the Columbia and Snake Rivers. **Yet the biological cost to salmon and steelhead of hydro operations is not zero.**

Hydropower is used to serve peak loads because dam operators can react to demand by adjusting water quantities sent through the turbines to generate electricity. But serving peak loads with hydropower kills millions of juvenile salmon every year. During certain times of the year, so much water is drawn down to generate electricity that salmon redds (gravel nests where salmon lay eggs) are uncovered or dewatered and their eggs die. Daily fluctuations change river water levels and juvenile fish that feed and live near the shore can be stranded and die when water levels are reduced. Migration of fish is interrupted when flows decrease at night because there is less demand for electricity and therefore less water moving through the reservoirs behind the dams. Operations outside

[8] Johnson, D., Hesse, J., Kinser, R., 2021. Nez Perce Tribe staff presentation on their analysis of Snake River basin Chinook and Steelhead—quasi-extinction threshold and call to action. https://www.nwcouncil.org/sites/default/files/2021_05_4.pdf.

of peak turbine efficiencies create cavitation and other conditions that significantly increase the mortality of fish passing through powerhouses. The projected increases in solar power, without adequate batteries or other storage, could create migration problems during many parts of the day. Fluctuations in reservoirs hurt resident fish by dewatering habitat and food supplies and reducing nutrients in the reservoirs.

Additionally, the water held behind storage dams for power generation would, under natural conditions, be in the river aiding the swift and timely downstream migration of young salmon. Saving this water for winter and summer energy production alters the natural (or normative) river conditions that aid juvenile salmon migration.

The recommendations in the 2022 *Energy Vision for the Columbia River Basin* are designed to reduce these problems while also saving money for utility customers. The Northwest electricity system has relied on the Columbia Basin dams to serve peak loads. The assumption has been that running more water through the generators is a low-cost way to meet the peak. This assumption has ignored the other costs of serving peak loads, including those related to the high costs of distribution and transmission of the electricity and the impact of peak load response on salmon survival. Transmission and distribution lines also have damaged other tribal resources, including First Foods and cultural sites. See **SECTION 3** and **APPENDIX E**.

2.1.2. Recent Spill Operations

Spilling water at the dams has proven to be the safest route of passage for juvenile salmon migrating downstream. Controversy over the timing and amount of spill to aid juvenile salmon migration has gone on for decades. A new generation of research made available by passively induced transponder tags (PIT tags) has enabled researchers to verify that juvenile salmon that avoid powerhouse encounters by passing through spillways return from the ocean as adult salmon in greater numbers than those salmon who encountered turbines or fish screens on their downstream migration. These developments have led to new programs for intentionally spilling water at the dams to improve salmon survival to adulthood.

In December 2018, the states of Oregon and Washington, the Nez Perce Tribe, Bonneville Power Administration, the Bureau of Reclamation, and the Army Corps of Engineers (Corps or Corps of Engineers) agreed in lieu of litigation to provide fish benefits, power system benefits, and operational feasibility for the 2019 and 2020 operating years. This short-term Agreement provided higher spill to benefit fish migration during periods of lower power value and lower spill occurs during periods of higher power value. In 2021, following requests for injective relief from the Court, the parties reached an interim agreement on operations of the eight federal mainstem Columbia and Snake River dams through July 31, 2022. This temporary agreement provides some increases in spill protections for migrating salmon, scales back zero generation operations noted below and restores commitments to minimum operating pool restrictions intended to facilitate juvenile salmon migrations.

2.1.3. Other Salmon Protections have been Weakened or Eliminated

While adopting flex spill arrangements as a recommended operation in the Columbia River System Operation EIS that concluded in mid-2020, the federal action agencies[9] adopted other changes that would reduce long-standing fish protections. The following changes during the Trump Administration served to increase flexibility in the operation of the hydroelectric dams, but reduced fish protections:

- Modification of winter draft limits at upper Columbia Basin storage reservoirs shifts water to generate power to meet winter electricity loads and away from the salmon migration season. For 40 years, fish managers have sought to maximize the spring freshet for fish migration and the Columbia River System Operations (CRSO). Reducing spring flows in the upper Columbia will slow migration timing.
- For the past 25 years the federal, state, and tribal fishery co-managers have requested that action agencies keep the mainstem run of river reservoirs as low as possible to decrease travel time (smaller reservoir surface area results in faster water evacuation time). The proposed action increases the opportunity to raise minimum operation pool (MOP) levels that slow fish travel times. Slower downstream migration times are associated with increased juvenile mortality.
- In the fall and winter, dam operators shut down flow at the Snake River dams at certain times of day (aka "zero generation") and allow water to pond for use at higher demand times. This operation can have a serious impact on migrating fish (adults and juveniles). The zero-generation operation was limited based on fish presence in the river and no zero generation before December 15. Now zero generation operations can occur as early as October 15 and have no constraints as to how many fish are in the river. Adult Snake River fall chinook are migrating through the end of November, steelhead are present year around and juvenile chinook can be present as late as November.
- Based on extensive research, the relationship between turbine operating efficiency and the mortality of fish passing through turbines is well understood. As a result, NOAA Fisheries has required, and dam operators now limit, turbine operations to within 1% of peak efficiency to prevent harm to migrating juvenile fish. Operating outside that range can cause cavitation and ultimately damage turbine blades.[10] The proposed action creates additional allowances for operating turbines outside the 1% range during salmon migration periods.
- For nearly 25 years it has been recognized that load following, or power peaking, operations can be detrimental to both fish and fishermen. In the winter of 2021, fish managers witnessed several consecutive days of power peaking at Dworshak Dam with daily outflow fluctuations of up to 9,000 cubic feet per second. This can dewater and damage salmon redds below the dam and move adult and juvenile fish out of the area.

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[9] The Bonneville Power Administration, U.S. Bureau of Reclamation and U.S. Army Corps of Engineers recently adopted records of decision based on the Columbia River System Operations Proposed Action, Environmental Impact Statement and NOAA Fisheries' Biological Opinion. These decisions have been challenged in federal district court by the State of Oregon and a coalition of environmental groups.

[10] The turbine blades in dams create pressure changes that cause bubbles around the blades.

Courtesy US Army Corps of Engineers

- The historic models that evaluate hydro system operations are generally operated on a daily average basis. The new spill operations are managed on an hourly basis. The action agencies have not proposed investment into updating the various models used to evaluate impacts and benefits of fish operations by adjusting to hourly time steps in their energy models.

In addition to these weakened salmon protections, BPA has also reduced the funding for other fish and wildlife measures by holding BPA's fish and wildlife costs level funded. BPA's 2018–2024 Strategic Plan sets programmatic limits at or below the rate of inflation. This has reduced, in real terms, funding available for its fish and wildlife program year after year, yet BPA's power rates were decreased 2.5%.

Energy planning and development must address the costs to the environment and manage energy resources to benefit tribal resources. The tribes have seen their salmon resources reduced from over 10 million fish to a mere fraction remaining in the river today while electricity rates in the Northwest are the lowest in the Nation. There is a better way. SECTION 3 describes the tribes' recommendations for achieving that path.

2.2

Dramatic Changes for the Energy System

The West Coast electric energy industry has gone through an extraordinary transformation since 2013. Some of the changes will result in dramatic improvements in addressing climate change that will benefit salmon and other tribal resources and begin to address the existential climate change threat. Some changes in the energy industry may have unintended consequences for fish, wildlife and cultural resources. This remainder of SECTION 2 describes the major industry changes; SECTION 3 provides CRITFC's recommendations to harmonize energy generation and transmission with the needs of fish, wildlife, First Foods, and cultural resources protection.

The federal and state policies and significant reductions in the costs of renewable resources will likely mean a change in how the region's dams will operate. Prior Energy Visions have also called for actions to reduce the impacts of the hydroelectric system on fish and wildlife by reducing peak loads and ensuring adequate energy reserve resources. However, when low-cost solar and wind energy is available, dams may be asked to store water. Electricity may be called upon from the dams to meet peak demands for several hours in the morning and several hours in the evening after sundown. If these operations result in slowing river flows for long periods during the day and night, reducing water spilled for fish passage, or operating turbines outside peak efficiency, fish will be adversely affected. Price signals need to be developed to prevent the hydropower system from being the sole battery backup for the wind and solar generators.

2.2.1. Greenhouse Emissions Policies and Standards

Concerns about the impacts of climate change, including rising temperatures, decreasing snowpack, increasing frequency and severity of extreme climate events, and changes in the magnitudes and timing of water flows caused by rising atmospheric greenhouse gas concentrations have grown since the last Energy Vision in 2013. Climate change is causing significant damage to fish and their habitat, and other tribal resources. This section describes state policies and laws designed to reduce greenhouse gas emissions.[11] The recommendations section addresses other issues to reduce reliance on fossil fuels in other energy sectors.

Washington, Oregon, and California have enacted limits on greenhouse gases from electricity generation that will mitigate climate change. In response to evolving these evolving state policies and other circumstances, many coal-fired power plants serving the West Coast have shut down or are scheduled to be decommissioned in the next few years. At the same time these thermal generation resources are being curtailed, the Northwest Power and Conservation Council is projecting a significant increase in low-cost solar and wind energy and reductions in electricity costs over the next twenty years.

WASHINGTON

The Clean Energy Transformation Act (CETA)[12] passed in 2019 requires all Washington state electric utilities to reach a 100% clean electric supply by 2045. CETA's first milestone requires the utilities to eliminate coal-fired resources from their state resource portfolios by the end of 2025. The second milestone requires utilities to be greenhouse gas neutral by 2030 with the flexibility to use electricity from natural gas if it is offset by other alternative compliance actions. By 2045, utilities must supply Washington customers with electricity that is 100% renewable or non-emitting, with no provision for alternative compliance actions.

Electric Utilities must adopt CETA by the end of 2021 with targets and plans. The Washington State Department of Commerce and Washington Utilities and Transportation Commission (UTC) play key roles on how to implement this law.

In 2021, Washington enacted the Carbon Commitment Act. It establishes a system of carbon pricing that sets economy-wide limits on carbon emissions beginning in 2023 and establishes a system to buy/sell allowances and offset credits and invest the proceeds in a range of activities that include restoration of marine and fresh waters, forest health, renewable energy, and public transportation.[13]

Washington's governor, Jay Inslee, recently proposed plans to spend $100 million annually to fund rebates for people buying electric vehicles. The proposal also increases the amount of the rebate to as much as $7,500 and expands the vehicles that are eligible. The plan also

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[11] Eighteen jurisdictions have set goals to achieve 100% clean, renewable energy. They are Arizona, California, Connecticut, Hawaii, Louisiana, Maine, Massachusetts, Michigan, Nevada, New Jersey, New York, New Mexico, Oregon, Rhode Island, Virginia, Washington, Washington, D.C., and Wisconsin. See https://www.cesa.org/projects/100-clean-energy-collaborative/table-of-100-clean-energy-states/.

[12] Chapter 19.405 RCW.

[13] https://ecology.wa.gov/Air-Climate/Climate-change/Greenhouse-gases/Reducing-greenhouse-gases/Climate-Commitment-Act.

includes $100 million in grants to state agencies, school districts, tribal and local governments, housing authorities, electric utilities, and nonprofit organizations to install solar energy and storage systems.

OREGON

In 2007, HB 3543 established the Oregon Climate Change Research Institute (OCCRI) to create science-based understanding for climate impacts, adaption, and mitigation.[14] It also created the Oregon Global Warming Commission to assess impacts of climate change and propose policies to reduce greenhouse gas emissions. The law set science-based climate emissions reduction goals for Oregon that include a reduction of carbon emissions to at least 75% below 1990 levels by 2050; however, the state is not on track to meet that goal. Oregon Global Warming Commission says Oregon will miss the 80 percent reduction mark of 80% by 2050 by 54 million metric tons carbon dioxide.[15]

In 2016, Oregon passed the Clean Electricity and Coal Transition Act[16] to transition off coal-fired power while committing to increase renewable resources. The Oregon Public Utility Commission will work with Portland General Electric and Pacific Power to develop implementation strategies to double the amount of clean renewable energy by 50% by 2040. By 2030, coal-fired resources for electric companies must be eliminated. In 2020, Oregon's largest investor-owned utility, Portland General Electric (PGE), shut its only coal power plant. The state has adopted a goal of net-zero emissions by 2040.

In 2020, Oregon's governor issued Executive Order No. 20-04 directing executive agencies to take actions to reduce and regulate greenhouse gas emissions, this specifically emphasizes the disproportionate effects that tribes will face. Governor Brown signed Executive Order 17-20 (regarding energy efficiency) and Executive Order 17-21 (regarding zero emission vehicles).

In 2021, Oregon passed HB 2021. Effective September 2021, HB 2021 requires retail electricity providers to reduce greenhouse gas emissions associated with electricity sold to Oregon consumers to 80 percent below baseline emissions levels by 2030, 90 percent below baseline emissions levels by 2035 and 100 percent below baseline emissions levels by 2040.[17] Electric companies must develop approved clean energy plans and convene Community Benefits and Impacts Advisory Group to assess the impacts of their clean energy plans on environmental justice communities and low-income ratepayers.

IDAHO

The State of Idaho has not adopted clean energy goals or regulations. However, Idaho Power has set a goal for 100% clean energy by 2045 with plans to invest in sources that take a "path away from coal."

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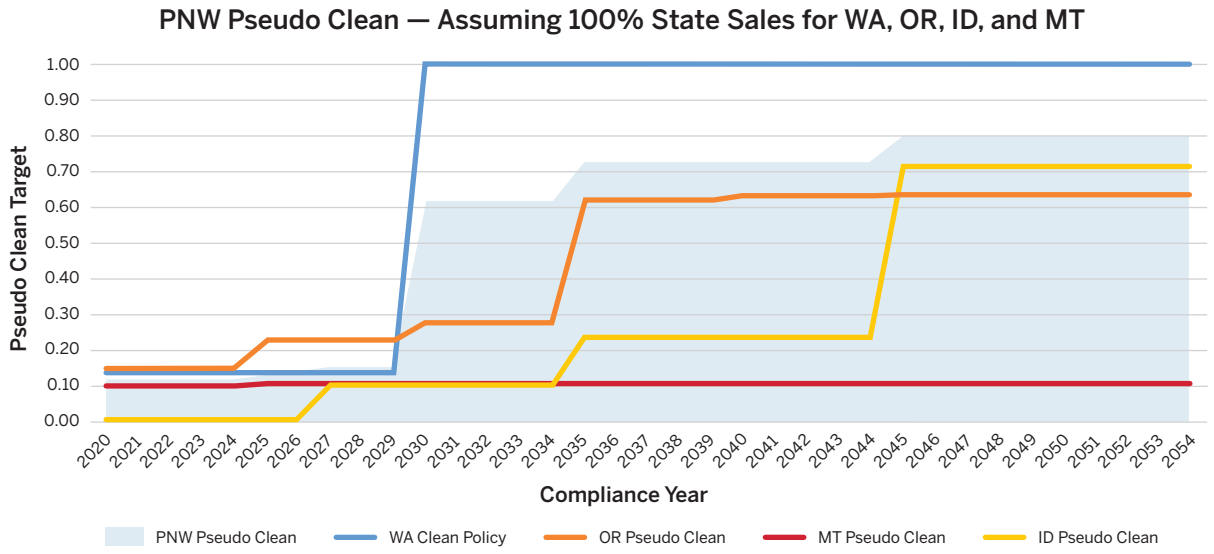
[14] Oregon Laws 2007, Chapter 907, Section 1 (narrative form).

[15] https://static1.squarespace.com/static/59c554e0f09ca40655ea6eb0/t/5fe137fac70e3835b6e8f58e/1608595458463/2020-OGWC-Biennial-Report-Legislature.pdf

[16] Senate Bill (SB) 1574-b (2016).

[17] Oregon Laws, 2021. Chapter 508

FIGURE 2. Targets for Carbon-Free Energy Production in the Northwest States



MONTANA

Several of Montana's largest cities have adopted standards to reduce greenhouse gases, including Bozeman, Helena, and Missoula. NorthWestern Energy reports that it serves Montana with an electric portfolio that is 60% carbon free and has set a goal to have an electric energy portfolio that reduces carbon by 90% by 2045, compared to 2010.[18] On May 14, 2021, Montana Governor Greg Gianforte signed House Bill 576, repealing the Montana Renewable Power and Rural Economic Development Act of 2005 and effectively annulling the Montana Renewable Portfolio Standard in its entirety.

The Northwest Power and Conservation Council prepared a chart (**FIGURE 2**) that shows the targets for carbon-free energy production in the northwest states.

CALIFORNIA

The 100 percent Clean Energy Act of 2018[19] requires California to have 50 percent of its electricity powered by renewable resources by 2025 and 60 percent by 2030, while ultimately working towards 100% zero-carbon electricity by 2045. California does not have any specific language for low-income communities but currently has multiple programs that serve low-income customers. The *2021 100 Percent Clean Energy Act Joint Agency Report* is a first step to evaluate the challenges and opportunities in implementing SB 100. This includes assessments and associated costs for the transition. This report requires a yearlong series of public workshops and comment opportunities. It was required by statute to meet with the disadvantaged communities' advisory group, who advise the energy commission and public utilities commission on energy equity issues.

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[18] https://www.northwesternenergy.com/environment/environmental-commitment/environmental-report/carbon-reduction-vision

[19] California Senate Bill 100.

BRITISH COLUMBIA

Almost all the electricity produced in BC comes from energy resources that do not depend on fossil fuels. Nonetheless, energy consumed in buildings, cars, and industrial operations represents nearly three quarters of the energy used and comes from fossil fuels. The legislated target for 2030 is a reduction of 25 million tons of greenhouse gases from the 2007 baseline. The CleanBC Plan[20] describes programs that will achieve 75 percent of that goal.

FEDERAL PROGRAMS

Congress recently passed the Infrastructure Investment and Jobs Act that provides funds for many of the actions described in the Energy Vision, including[21]:

- $7.5 billion for electric vehicle charging.[22]
- Directs states to consider greater electrification of the transportation section.
- Expanded data collection on electric vehicle integration with electricity grids.
- $5 billion for electric grid reliability research, development, and demonstration and $1 billion for rural or remote areas.
- Requires state utility regulators to consider establishing rate mechanisms to allow utilities to recover the costs of promoting demand-response practices.
- The Department of Energy will study siting electric transmission lines to designate National Interest Electric Transmission Corridors.
- Establishes a $2.5 billion revolving loan fund for new transmission lines or upgrades.
- $3 billion for Smart Grid investments.
- $10 billion in additional borrowing authority for BPA.
- $1 billion to upgrade transmission between Canada and the U.S. related to the Columbia River Treaty.
- $100 million for Northwest water storage and hydroelectric capacity.
- $10 million to study better coordination of water and power flows between British Columbia and the Pacific Northwest.
- $3.125 billion for battery processing and manufacturing.
- $200 million for electric vehicle battery recycling and second-life applications.
- $100 million for carbon capture technology.
- $9.5 billion for clean hydrogen programs.
- $75 million for hydroelectric efficiency improvements.
- $554 million for maintaining and enhancing hydroelectric facilities.
- $10 million for pumped storage hydropower wind and solar integration.
- $250 million for an energy efficiency revolving fund.
- $40 million for energy auditors training program.
- $3.5 billion for the Weatherization Assistance Program.

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[20] https://www2.gov.bc.ca/gov/content/environment/climate-change

[21] See Infrastructure Investment and Jobs Act—Section by Section Summary pdf at https://www.cantwell.senate.gov/download/iija-section-by-section.

[22] The funding will focus on rural, disadvantaged and, hard-to-reach communities. States, tribes, and local governments are eligible for the funding.

- $550 million for the Energy Efficiency and Conservation Block Grant Program.
- $505 million for energy storage demonstration projects.
- $3.5 billion for carbon capture demonstration and pilot projects.
- $264 million for wind, solar, and geothermal energy projects.
- $500 million for low-income housing energy assistance.
- $216 million for tribal climate resilience.

The Jobs Act includes $10 million to study increasing coordination of the operations of hydroelectric and water storage facilities on rivers located in the United States and Canada. The study will consider changes in electricity supply; potential reductions in greenhouse gas emissions, potential need of increased transmission capacity; and other factors for increasing bilateral coordination. A related section established an account in the Treasury "for activities to improve electric power system coordination by constructing electric power transmission facilities within the western United States that directly or indirectly facilitate non-carbon emitting electric power transactions between the western United States and Canada." The amount in the fund will be based on the five-year total of the Canadian Entitlement prior to the enactment of the Act.

The Biden Administration has also proposed approximately $550 billion in investment to accelerate a clean energy transformation in the Build Back Better legislation. It includes building electric infrastructure and efforts to support renewable energy. The bill calls for a million new affordable, energy-efficient housing units and making existing structures more energy efficient. Hundreds of billions of dollars would go toward green energy industries of the future, such as advanced battery manufacturing.

As mentioned, congressmen Simpson and Blumenauer are working on an initiative to help endangered salmon recover by breaching the four dams along the Lower Snake River and funding other restoration efforts. The initiative includes significant funds to replace the electricity the dams generate with renewable resources and energy efficiency, mitigate for the effects of dam removal, and address the needs of farmers and ranchers and local communities that depend on the current operation of the dams.

2.2.2. Coal Plants Are Phasing Out

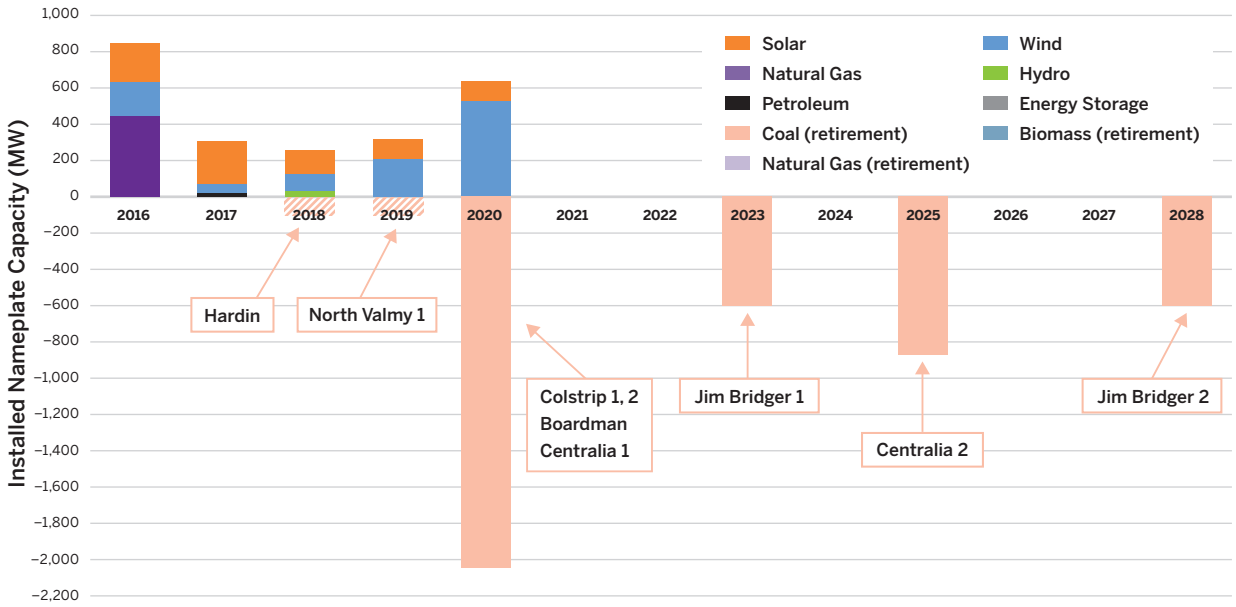
One of the results of state and federal policies has been a significant reduction in the number of coal plants serving the Pacific Northwest—the current and estimated total retirements between 2018 and 2028 is 6,184 MW (roughly the amount of power needed to serve five Seattle-sized cities). **FIGURE 3** is from the NPCC Project Database. PacifiCorp in its 2021 Integrated Resource Plan workshops stated that it plans to retire Colstrip 3 & 4 in 2025[23] and Jim Bridger 3 & 4 by 2037[24]; these four plants total 2,700 MW of capacity. To put this in perspective, there have only been a few years with minor resource reductions over the past 25 years.[25] This Energy Vision seeks to assure that these plant reductions will be served without putting more burden on the Columbia River and its fish and wildlife resources.

[23] December 2020 and August 27, 2021 workshops.

[24] July workshop.

[25] See https://www.nwcouncil.org/energy/energy-topics/power-supply

FIGURE 3. Generating Capacity Additions and Retirements Since the Seventh Power Plan (including Announced Planned Retirements)



2.2.3. Electricity Resource Adequacy Issues

Power blackouts in Texas and California have increased public concern about adequate electricity supplies. Electricity is an essential service and disruptions can threaten life and safety.

The problems in Texas were the result of extreme low temperatures and a power system that did not require utilities to weatherize their power plants or have adequate power reserves. The shortages affected 4 million households in February 2021.[26] Some Texas politicians tried to shift the blame to renewable resources—but the facts showed that the Texas renewable resources produced more energy than was projected during the cold snap.

California's blackouts during August of 2020 were much smaller, but closer to the Pacific Northwest and occurred in a power grid that is connected to the Columbia Basin. The California Public Utilities Commission and Independent System Operator are working to address outdated forecasts and planning targets that created these outages.[27]

The NPCC monitors the adequacy of electricity supplies to meet loads and calculates a "loss of load probability" (LOLP). The current Northwest standard calls for the power supply to have sufficient resources (both generating and energy efficiency) to limit the likelihood of a shortfall to no more than five percent.[28] In recent years, the NPCC analysis has shown LOLP in the 7 percent range.

The NPCC's draft 8th Power Plan finds few adequacy issues in the short term and more uncertainty later:

> *The strategy in the Draft 2021 [8th] Power Plan shows that the regional power supply will be adequate in the near term. In later years, with the retirement of more fossil-fuel burning generators, adequacy takes a more prominent role in the regional strategy, especially under certain policy scenarios that increase regional demand (e.g., decarbonization policies). For the plan analyses, the Council used climate-change projections for temperature and precipitation rather than historical climate data, and this tended to shift resource adequacy needs from winter to summer—more precipitation and lower temperatures in winter, less precipitation and higher temperatures in summer.*

The NPCC found that in the near term, electricity supplies would be adequate if utilities committed to running their thermal resources, regardless of the market price. Without such a commitment, some thermal resources might not be available because they are much more expensive than renewable resources.

By 2025, the NPCC studies show:

> *...that **off-peak** market prices rise sufficiently high (due to load growth and other factors) to prompt more regional thermal units to commit. Thus, even with the announced retirement of the Jim Bridger 1 coal plant (530-megawatts) by the end of 2023, the resulting LOLP for 2025 is zero.*[29]

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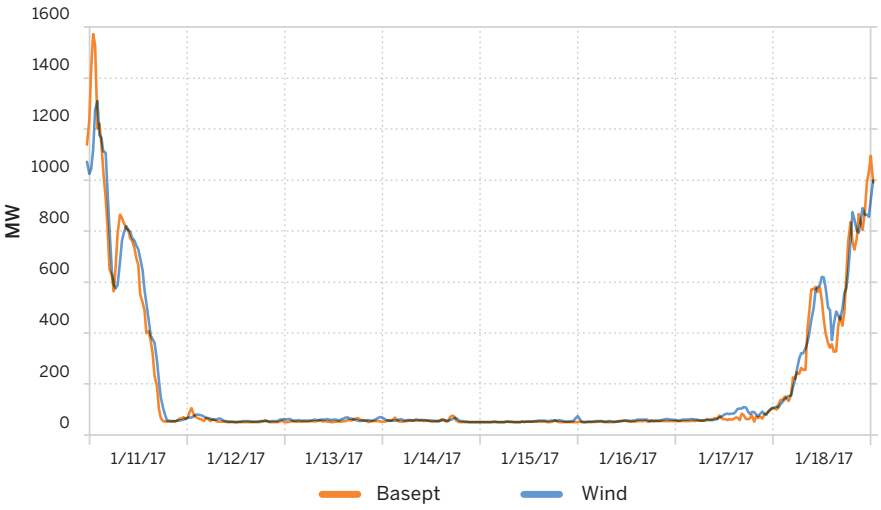
[26] *Tale of Two Grids*, see https://www.nrdc.org/experts/ralph-cavanagh/tale-two-grids-texas-and-california

[27] See Resource Adequacy Recommendations in SECTION 3.

[28] The five percent standard does not mean that there is a less than five percent change of a shortfall in a given year, rather it means that after modeling thousands of permutations of potential future conditions (*e.g.*, load forecast, weather profile, hydro conditions, etc.) it found a resource shortfall in less than five percent of those model runs.

[29] https://www.nwcouncil.org/2021powerplan_resource-adequacy-assessment

FIGURE 4. BPA Balancing Authority Total Wind Generation, Wind Basepoint, and Oversupply Mitigation (January 11–18, 2017)



Based on 30-minute readings from the BPA SCADA system for points 79687, 103349, 114476. Balancing Authority Wind Generation in Orange, Wind Basepoint in Blue. Data provided by BPA Technical Operations (TOT-OpInfo@bpa.gov).

Several studies on resource adequacy in the Northwest have raised near-term concerns. A paper by Randy Hardy and Larry Kitchen and a study by E3 describe the retirement of the coal plants that serve the region and the effects on meeting peak energy demands, especially if there is a low-water year combined with a cold snap.[30]

More recently, utilities have raised questions about the NPCC's analysis. One of the biggest issues appears to be how much can the region depend on renewable resources imported from California and the Southwest. The California Public Utilities Commission has called on utilities to acquire 11,000 megawatts of renewable resources; however, some of this power will be used to charge batteries to meet peak loads so the net addition that might be available in the Northwest is not clear. Over-reliance on California imports were a precipitating factor for the 2001 West Coast energy crisis.

Maintaining the reliability of the Northwest electricity systems will become more complex as coal and natural gas-fired power plants phase out and renewable resources play a large role. **FIGURE 4** shows wind production in the BPA service area during an extended cold spell in mid-January of 2017. Despite nearly zero wind production in the Northwest, demand was met through hydro and thermal generation. If thermal generation is removed, load goes up due to electrification of the economy and a low water year occurs, meeting demand will be a real challenge for the Northwest. Further stressing the Columbia River's ecosystems to meet this type of demand is not acceptable. Rather the Northwest Power Pool is developing a Resource Adequacy Program to address these issues and should assure resource adequacy without placing risk on the river's fish and wildlife resources. Please see the CRITFC resource adequacy recommendations in SECTION 3.

[30] Hardy and Kitchen, *Future Northwest Capacity Shortages, July 17, 2019*.

2.2.4. Significant Increases in Solar and Wind Energy

The costs of wind and solar generation have declined significantly in comparison with other new generating resources. **TABLE 1** shows costs from the Energy Information Agency *2021 Annual Energy Outlook*.

WIND ENERGY

Over the past twenty years Northwest wind energy has grown from 110 MW to 9,417 MW—about 15 percent of the region's total capacity. On an annual basis, wind power is supplying 2,978 average megawatts of power for the region—about 9 percent of the total.

TABLE 1. Estimated Unweighted Levelized Cost of Electricity (LCOE) and Levelized Cost of Storage (LCOS) for New Resources Entering Service in 2026 (2020 dollars per megawatthour)

Plant type	Capacity factor (percent)	Levelized capital cost	Levelized fixed O&M[i]	Levelized variable cost	Levelized transmis-sion cost	Total system LCOE or LCOS	Levelized tax credit[ii]	Total LCOE or LCOS including tax credit
Dispatchable technologies								
Ultra-supercritical coal	85%	$43.80	$5.48	$22.48	$1.03	$72.78	NA	$72.78
Combined cycle	87%	$7.78	$1.61	$26.68	$1.04	$37.11	NA	$37.11
Combustion turbine	10%	$45.41	$8.03	$44.13	$9.05	$106.62	NA	$106.62
Advanced nuclear	90%	$50.51	$15.51	$9.87	$0.99	$76.88	–$6.29	$70.59
Geothermal	90%	$19.03	$14.92	$1.17	$1.28	$36.40	–$1.90	$34.49
Biomass	83%	$34.96	$17.38	$35.78	$1.09	$89.21	NA	$89.21
Battery storage	10%	$57.98	$28.48	$23.85	$9.53	$119.84	NA	$119.84
Non-dispatchable technologies								
Wind, onshore	41%	$27.01	$7.47	$0.00	$2.44	$36.93	NA	$36.93
Wind, offshore	44%	$89.20	$28.96	$0.00	$2.35	$120.52	NA	$120.52
Solar, standalone[iii]	29%	$23.52	$6.07	$0.00	$3.19	$32.78	–$2.35	$30.43
Solar, hybrid[iii, iv]	28%	$31.13	$13.25	$0.00	$3.29	$47.67	–$3.11	$44.56
Hydroelectric[iv]	55%	$38.62	$11.23	$3.58	$1.84	$55.26	NA	$55.26

Source: U.S. Energy Information Administration, Annual Energy Outlook 2021

[i] O&M = operations and maintenance

[ii] The tax credit component is based on targeted federal tax credits such as the production tax credit (PTC) or investment tax credit (ITC) available for some technologies. It reflects tax credits available only for plants entering service in 2026 and the substantial phaseout of both the PTC and ITC as scheduled under current law. Technologies not eligible for PTC or ITC are indicated as NA, or not available. The results are based on a regional model, and state or local incentives are not included in LCOE and LCOS calculations.

[iii] Technology is assumed to be photovoltaic (PV) with single-axis tracking. The solar hybrid system is a single-axis PV system coupled with a four-hour battery storage system. Costs are expressed in terms of net AC (alternating current) power available to the grid for the installed capacity.

[iv] As modeled, EIA assumes that hydroelectric and hybrid solar PV generating assets have seasonal and diurnal storage, respectively, so that they can be dispatched within a season or a day, but overall operation is limited by resource availability by site and season for hydroelectric and by daytime for hybrid solar PV.

SOLAR ENERGY

Utility scale solar projects have grown from 9 MW in 2013 to 649 MW in 2019. These solar plants represent 1 percent of the installed capacity of the region's energy system. These plants provided 132 average megawatts of electricity in 2018.

FIGURE 5 was developed by the Council and shows wind and solar additions between 1998 and 2020.

The Council projects a significant increase in the future. **FIGURE 6** shows the additional renewable resources that would be built under the Council's assumed baseline conditions. It shows that

FIGURE 5. Regional Wind and Solar Brought Online

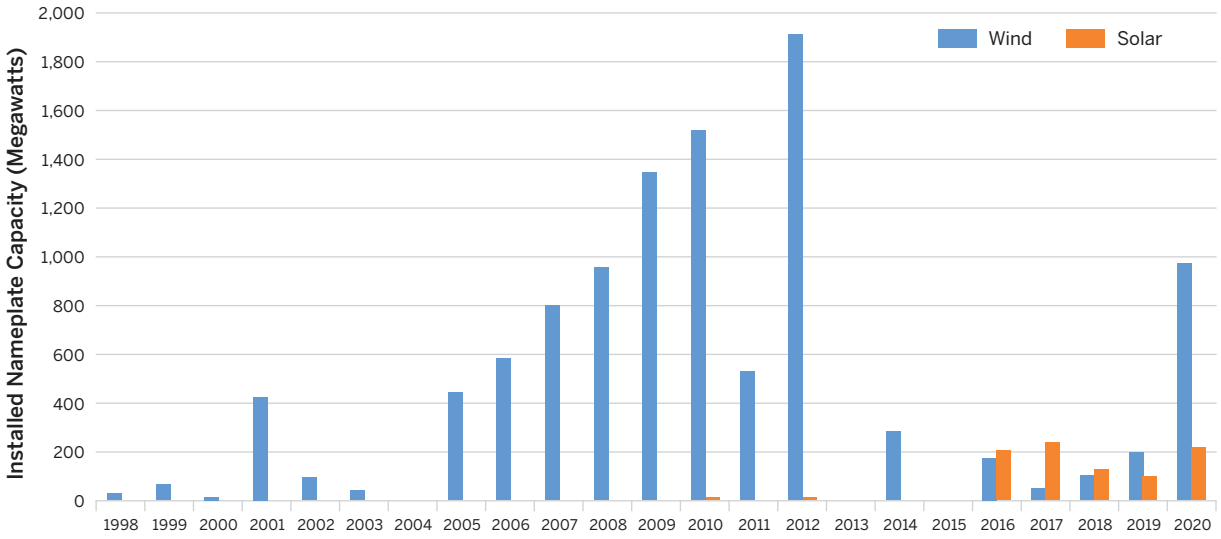
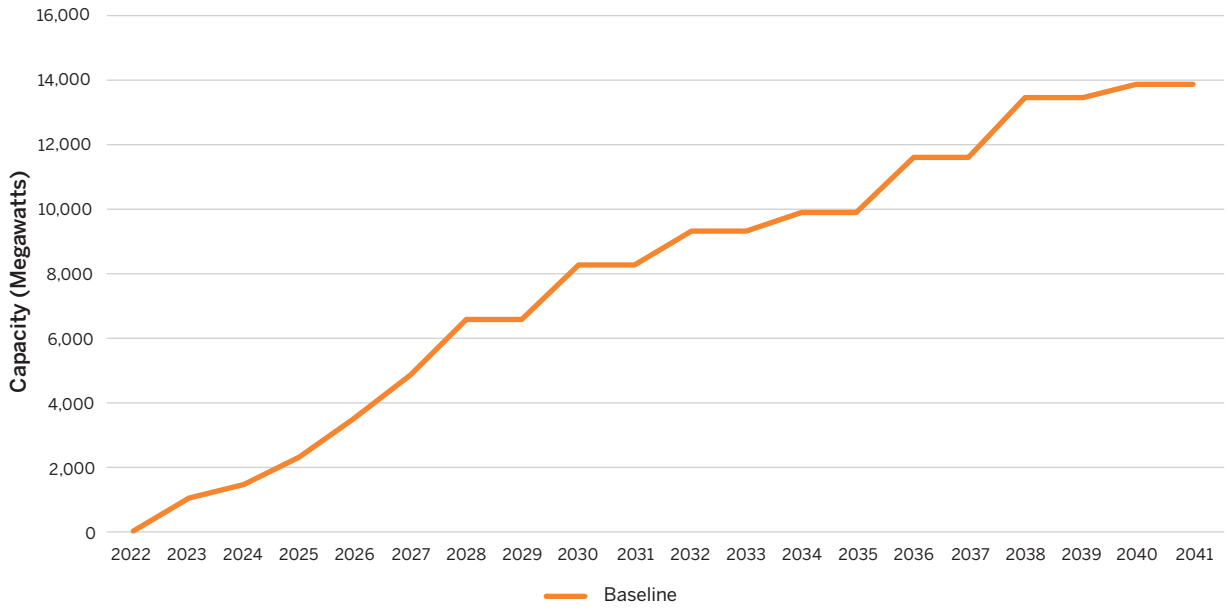


FIGURE 6. Forecast of Renewable Build



solar and wind projects could add approximately 5,000 megawatts of capacity in the northwest by 2027, growing to 14,000 megawatts by 2041.[31] The Council's draft 8th Power Plan recommends that 3,500 megawatts of these resources be built by 2027.

This growth is not unique to the Northwest. Solar and wind plants in the western energy system are also projected to increase dramatically. **FIGURE 7** is a projection by the Western Energy Coordinating Council (WECC).[32] It shows solar utility and wind projects will increase by 200,000 MW by 2028. Utility solar projects are projected to grow to 150,000 megawatts of installed capacity. Solar systems with batteries will add an additional 200,000 megawatts by 2045. It also shows wind projects increasing to 50,000 megawatts by 2045—for a total new renewable resource capacity of approximately 400,000 megawatts. The WECC projections would mean a dramatic increase. For comparison, the current energy capacity of the WECC is 276,000 megawatts from all sources; this total includes 29,000 megawatts of wind and 23,000 megawatts of solar.

A major reason for this renewable energy growth is that the costs of solar and wind energy sources have decreased significantly over the past ten years, not simply regulatory policies. The Lazard investment bank publishes a yearly summary of generation costs. Their summary uses actual transaction data—not

[31] Northwest Power and Conservation Council presentation, May 2021.

[32] The WECC is comprised of 14 western states, two Canadian provinces, and northern Baja Mexico.

FIGURE 7. WECC Buildout of Solar and Wind Plants in the Western Energy System

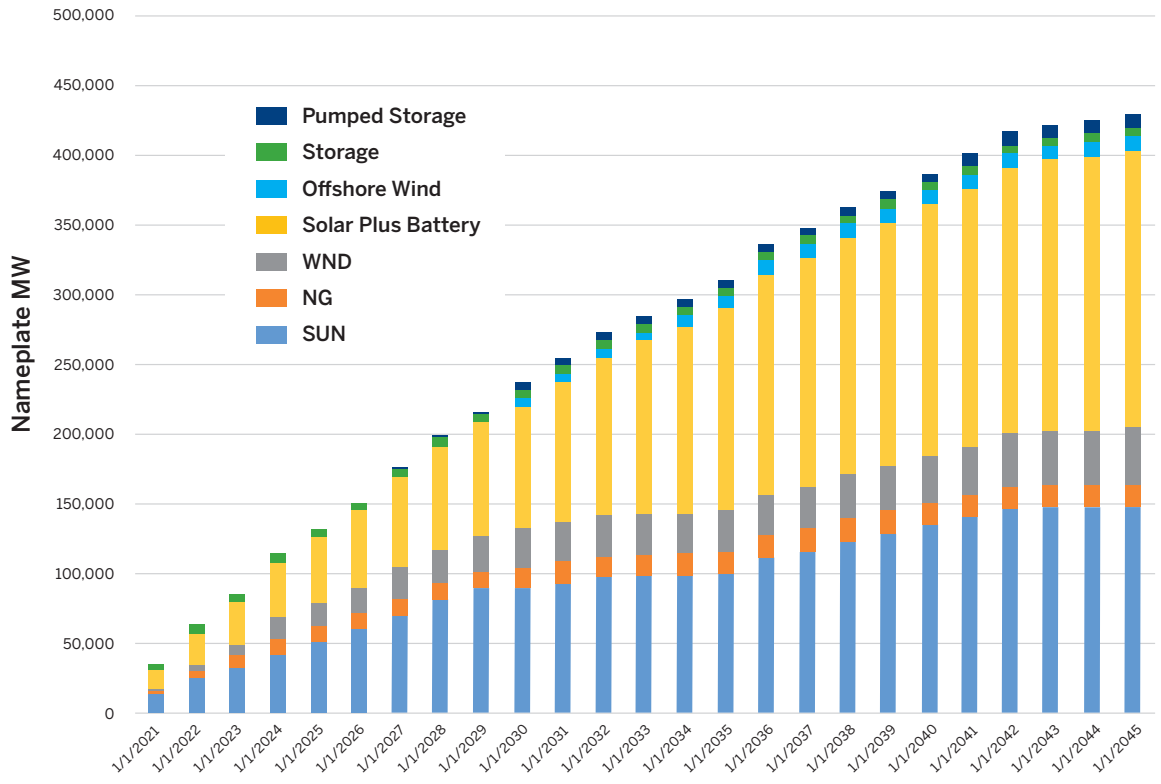
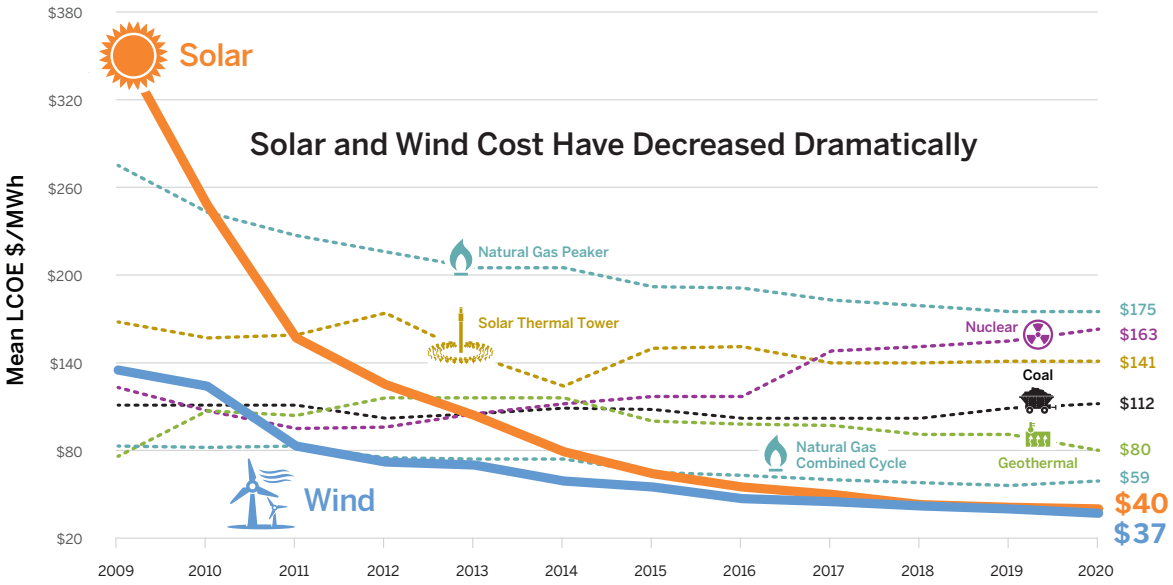


FIGURE 8. Yearly Summary of Solar and Wind Generation Costs



Source: Lazard's Levelized Cost of Energy Analysis—Version 14.0

estimates—and is commonly viewed as authoritative. The most recent chart **(FIGURE 8)** and shows costs per megawatt hour ($/MWh). The bold orange arrow shows the evolution of solar costs; the purple arrow shows wind costs.[33]

The Council has found that the costs of residential solar systems have also declined significantly and projects that these costs will continue to decrease by 7% per year. The Council's draft 8th Power Plan projects 1,513 megawatts of capacity by 2039 and 7,019 megawatts by 2045. These systems will supply electricity directly to the homes and business to meet their needs. This will decrease the demand for electricity from central station power plants. Any surplus power from these residential and commercial solar systems is sold to the local utility. The Council forecast is shown in **FIGURE 9**.

Offshore wind energy is another renewable resource that will be coming online in the Northwest in the next 10 years. The state of Oregon and the Bureau of Ocean Energy Management (BOEM) committed to offshore wind energy planning in June of 2020.[34] In March 2021, the Department of Interior and the Department of Energy and Commerce committed to establishing 30 gigawatts of offshore wind energy by 2030, and in May, the Biden Administration announced that it will focus on the first U.S. commercial-scale wind projects off the Pacific Coast.[35] California's offshore wind energy development is expected to bring in up to 4.6 gigawatts of clean energy to the grid over the next decade, enough to power 1.6 million homes.[36]

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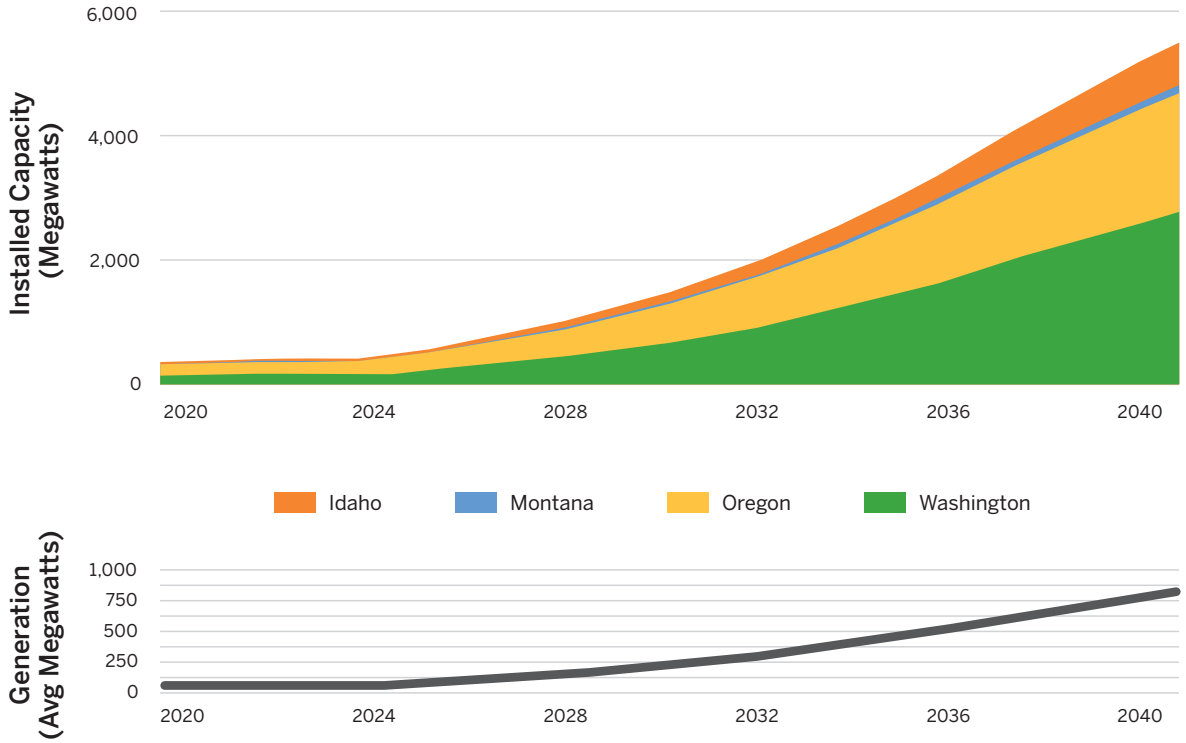
[33] Lazard's Levelized Cost of Energy Analysis—Version 14.0", Lazard Bank, October 2020, page 8. Emphasis supplied by McCullough Research."

[34] https://dailyyonder.com/from-extraction-to-sustainability-oregons-southern-coast-and-the-emerging-blue-economy/2021/09/13/

[35] https://www.northcoastjournal.com/NewsBlog/archives/2021/08/11/offshore-wind-energy-offers-tremendous-promise

[36] *Id*.

FIGURE 9. Forecast of Behind-the-Meter Solar Installed Capacity and Generation by State[37]



The impacts of integrating offshore wind energy with Columbia River hydropower are yet to be determined. The BOEM touts offshore wind as an abundant domestic energy resource and indicates that offshore winds tend to blow harder and more uniformly than on land.[38] Concerns with offshore wind development include effects on ocean fisheries, the unknown impacts to marine life and ecosystems from the existence of offshore wind turbines, and the disruption to the seabed from burying of transmission lines. The Confederated Tribes of the Coos, Lower Umpqua and Siuslaw have urged a careful approach in addressing these issues.[39]

2.2.5. Energy Efficiency Has Improved

Since 1978, energy efficiency has saved more than 7,200 average megawatts in the Pacific Northwest. That is half the region's growth in demand for electricity, or enough power for six cities the size of Seattle. These efficiency improvements have saved Northwest consumers over $70 billion dollars and the savings are growing at $5 billion per year. These programs have also reduced greenhouse gas emissions by more than 240 million metric tons.

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[37] Draft 2021 Power Plan page 3–20.

[38] https://www.boem.gov/renewable-energy/renewable-energy-program-overview

[39] https://dailyyonder.com/from-extraction-to-sustainability-oregons-southern-coast-and-the-emerging-blue-economy/2021/09/13/.

Energy Efficiency reduces peak loads.[40] The Northwest Power and Conservation Council's Regional Technical Forum estimates that from 2013 through 2019 the region has saved 1,770 average megawatts of energy through its conservation programs. These savings reduced winter peak demand by slightly more than 3,200 megawatts and just over 2,000 megawatts of summer peak demand.

2.2.6. Major Changes in the West Coast Energy Market Must Be Implemented in a Way That Helps Salmon and Steelhead

The hydroelectric system in the Northwest is currently used to help integrate intermittent wind and solar energy. As West Coast solar power grows, some energy planners assume that the Columbia River dams will help store some of this energy during daylight hours by reducing electricity production and keeping more water in the reservoirs for releases at other times. Under this assumption, the dams would release the water and generate more electricity when solar power is not available—this is projected to occur for a couple of hours in the morning and about four hours after the sun goes down. Salmon and steelhead bear the burden of operating the hydrosystem as a battery for integrating wind and solar energy; instead, by appropriate planning and implantation of wind and solar in conjunction with actual batteries, these burdens can be avoided.

The WECC-wide increase in renewables is changing historical patterns of market prices. In the past, electricity prices were higher in the summer due to high air conditioning loads across California and the southwest and lower prices occurred in the winter due to excess capacity in California and the southwest. California solar development is now depressing summer wholesale market values during daylight hours. These conditions are expected to continue as California and the Southwest develop more solar to reduce greenhouse gases and meet renewable resources standards without the ability to store excess generation.

Preliminary analysis for next Council Power Plan indicates that wholesale market prices are forecast to be low in the winter and spring, reflecting the impact of the Northwest's reliance on hydropower and increased renewables throughout the west. In prior years with a larger water run-off, the Northwest even experienced short periods of negative wholesale market prices during the spring when both hydropower and wind output created conditions of oversupply.

In the future, longer and more frequent periods of negative wholesale market prices are forecasted for not only the spring, but many hours during the winter, spring and fall seasons. The summer month prices are expected to be comparatively higher, especially during the evening hours when the sun goes down and solar generation drops to zero. But even summer prices become lower over time on an average basis because the low midday prices decrease as more solar generation is added throughout the west.

[40] Fish managers are under constant pressure by dam operators to allow turbine operations outside of peak efficiency to meet short term power system needs due to unexpected curtailment in other generating resources, weather conditions causing peak energy demand and other factors. Proactively addressing these power system demands through conservation measures, rather than excursions from hydro operating criteria is sound environmental and economic policy.

3 Recommendations

Recommendations of the 2022 Energy Vision for the Columbia River Basin

The Northwest needs to take bold action to achieve the Energy Vision for the Columbia River Basin. The recommendations in this section are intended to put the region on a path toward affordable, carbon-free energy that harmonizes with the ecosystem. These recommendations prioritize energy efficiency, renewable resources, new storage technologies, reductions in peak loads, and other strategies that are compatible with the needs of fish and wildlife. These actions would reduce the impacts of renewable resource projects and transmission lines on tribal resources and save consumers money.

These actions will move the region in the direction of addressing the climate crisis and transitioning the electricity system to be compatible with healthy and harvestable salmon populations and to be less damaging to other tribal resources.

3.1
River Restoration and Improved Dam Configurations and Operations

As Congress acknowledged in 1980, the survival of the Basin's salmon is substantially dependent on the environmental conditions resulting from hydroelectric system operations in the Columbia Basin. The federal and non-federal hydro projects in the Basin have continually adapted their configuration and operations to improve the survival of affected fish and wildlife populations. However, the current anadromous fish resources in the Basin are imperiled with a very uncertain future. Future physical and operational hydro project adaptations are continually being considered by tribal, state, and federal sovereigns.

RECOMMENDATION 1

The region should prepare to implement river restoration, and dam configurations and operations that are compatible with, and support healthy, harvestable fish populations, as detailed in this section and APPENDIX C. These recommendations include breaching the four lower Snake River dams, spill operations at run of river dams, flow related operations at storage dams, structural modifications to aid salmon and lamprey passage, needed maintenance, flood control studies, actions to improve water temperatures, and capability for lower Snake River dam breaching.

- Near-term operations characterized by maximized spill during the spring, moderate spill during the summer, and low-level spill during the fall and winter at lower Snake and lower Columbia projects.
- Long-term operations characterized by breached lower Snake projects, and maximized spill during the spring, moderate spill during the summer, and low-level spill during the fall and winter at lower Columbia projects.
- Management of reservoir pools at their minimum elevations (MOP) during spring and summer periods.
- Minimization and/or elimination of within day load following (power peaking), including elimination of extreme zero-flow (zero generation) operations.

- Seasonally manage/shape flows in ways the reflect natural hydrograph patterns and processes.
- Maintain and improve existing fish passage facilities at the federal Columbia and Snake River dams.
- Allow for fish-based Total Dissolved Gas (TDG) waivers year-round.
- Move the Corps of Engineers' annual systemwide "Control flow" for the Columbia River at The Dalles to 450,000 cfs (bankfull) and gradually ramp up to 550,000 cfs (flood-flow).
- Secure three to five million acre-feet of storage in Canadian Columbia Basin reservoirs to be used for salmon migration support.
- Implement ecological rule curves that store additional water in the upper reservoirs (primarily at Grand Coulee) to preserve adequate flows for migrating juveniles and adults during the spring and summer months.
- Improve adult and juvenile passage for Pacific Lamprey at the dams.
- Develop a long- and/or short-term sediment budget model throughout the Columbia River Basin with specific focus on the Cold-Water Refuges (CWR) along the river.
- Maintain energy reserves to meet fish and wildlife obligations. Increasing planning reserve margins, reducing peak loads, storage, demand response, and increasing energy efficiency and renewable resource development will all help reduce risks to fish and wildlife and the region's economy during low-water years.
- Implement EPA's 2021 TMDL for Temperature in the Columbia and Lower Snake Rivers.

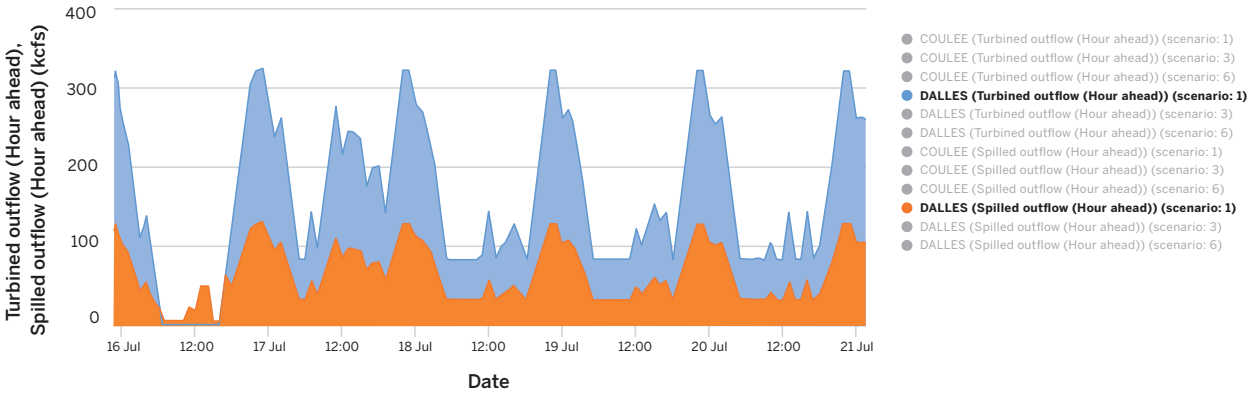
Because the future is inherently unknowable, energy planners long ago built a range of potential futures into their planning, including variations in energy demand, climate, and new energy resource development. But this planning has not assumed future variations in planned hydro system configurations and operations needed for fish survival. There is no legal requirement for this practice. Since the current status of salmon and steelhead populations are still not improving, it is certain that additional constraints will be sought by sovereigns and others.[41] Energy and related planning should anticipate a range of potential biological conditions and needed environmental actions and operations over time to improve anadromous fish survivals.

Energy planners often refer to fish operations as "constraints" and have assumed that in the absence of a defined fish operation, the energy system and hydro operations will be unconstrained for anadromous fish needs and optimized for power production. This can lead to aberrant circumstances unlikely to be tolerated by environmental managers. For example, a sampling of current GENESYS modeling analysis for a one-week period in July 2031 **(FIGURE 10)**, indicates that Columbia River flows below The Dalles Dam could approach zero kcfs during daylight hours, presumably due to the amount of solar energy produced at that time.

Compared to current conditions, this drastic operational change would have implications for water temperature increases, delayed salmon

[41] On October 21, 2021, the United States, plaintiffs and aligned amicus in *NWF v. NMFS* filed an Unopposed Motion to Stay Litigation with a short-term agreement for operations of the Columbia River System. The agreement includes planned Spring fish passage spill operations for 2022, planned Fall/Winter Spill Operations, reservoir operations and other matters.

FIGURE 10. Sampling of Current GENESYS Modeling Analysis for a One-Week Period in July 2031



migrations, treaty fisheries and spill operations at other lower Columbia River dams, such as Bonneville Dam where spill is managed to set flow levels.[42] Such operations are highly unlikely to be tolerated.[43]

Given the imperiled condition of fish stocks impacted by Federal Columbia River Power System (FCRPS) dams and other important non-federal dams in the Basin, it is prudent to assume variations in hydro configuration and operation due to modified fish constraints going forward. The following sections describe actions that may be needed to sustain these species.

3.1.1. Actions for the Columbia River System

MAINSTEM SNAKE AND COLUMBIA RIVER DAM OPERATIONS

RECOMMENDATION 1.1:

Increase hours of expanded spill.

Near-term operations should be characterized by maximized spill during the spring, moderate spill during the summer, and low-level spill during the fall and winter at lower Snake and lower Columbia projects. Long-term operations should be characterized by breached lower Snake projects, and maximized spill during the spring, moderate spill during the summer, and low-level spill during the fall and winter at lower Columbia projects. Future spill management

[42] The U.S. Environmental Protection Agency's comments on the draft Energy Vision emphasized that Columbia River warming water temperatures have prompted EPA to issue TMDL limitations for hydro system operations. Changes in operations that would increase water temperatures, such as lower flows during summer daylight hours, would run counter to the policies of the Clean Water Act.

[43] Fishery managers have been calling for higher flows in the spring and summer to help young salmon migrate from their natal streams to the ocean for more than forty years. Imagine the challenges to a juvenile salmon trying to migrate down the Snake and Columbia if the rivers only flow for a few hours in the morning and evening while the rest of the day the river slows to store energy from solar projects. Rapid increases and decreases in flow have also been shown to stop or delay adult fish migration. The changes in flow projected in the Council analysis could make these migration problems much worse in future years.

should include minimum volumetric spill levels developed for each dam to address threats of zero flow operations and large swings in power peaking that is being predicated for future hydro operations.

RECOMMENDATION 1.2:
Allow for increased total dissolved gas waivers year-round.

To support the Flex Spill Operations Agreement, the states removed the forebay TDG limit for spring 2019 operations, allowing operations to be curtailed only by the 120% TDG tailrace limit.[44] For 2020, the states raised the tailrace limits to 125% TDG for the spring passage season, allowing for even more spill at each dam.[45] These increases in TDG waivers should be enacted year-round and allowed for purposes other than fish passage to allow for more flexibility in water management and flood control operations.

RECOMMENDATION 1.3:
Reduce power peaking.

Reduce Power Peaking at passage dams during emergence and migration periods to reduce stranding of fry and smolts. This operation is currently implemented below Priest Rapids Dam with tremendous success for the Hanford Reach Fall chinook population. Power peaking can also cause temporary disturbance or oscillation in the water level that can confuse downstream and upstream migrants and increase travel time.

RECOMMENDATION 1.4:
Prohibit periods of zero flow.

Periods of very low or zero flow are currently allowed and are not based on biological triggers, such as the number of fish present in the river. Zero flows should only be allowed when biological triggers have been met to ensure there is little to no risk to migrants. Constraints need to be integrated into the power operations to maintain minimum levels of flow when fish are present in the system.

RECOMMENDATION 1.5: Expand and modify periods of spill for adult passage.

Increase periods of planned spill during fall, winter, and early spring seasons to aid adult salmon and steelhead overshoots, as well as to aid kelt migration during the early spring prior to the initiation of the spill season.

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[44] For a more detailed explanation, see the Corps of Engineers' Fish Operation Plan for 2019 at 2, available at http://pweb.crohms.org/tmt/documents/fpp/2019/final/FPP19_AppE.pdf.

[45] See http://pweb.crohms.org/tmt/documents/fpp/2020/final/FPP20_AppE_FOP.pdf for more details.

OTHER HYDRO-ACTIONS TO IMPROVE SALMONID SURVIVAL

RECOMMENDATION 1.6: Implement structural modifications at Grand Coulee to allow drum gate maintenance to occur regardless of flow year and reduce the required draft to perform the work.

This draft can have large impacts in early spring flows or put the region in the position to have to choose between spring and summer flows since it may preclude providing adequate flow during both time periods.

RECOMMENDATION 1.7: Operate Dworshak Dam on the North Fork Clearwater River to better mimic the spring freshet.

Current flood control drafts occur early in the winter when there is little information on what type of flow year will be realized. This can easily lead to excessive deep drafts that make it challenging to achieve refill, let alone provide spring flow augmentation.

RECOMMENDATION 1.8: Install additional turbines at key projects.

Install additional turbines at projects such as Libby and Dworshak to allow for more flexibility in moving water and reduce the risk of over drafting due to project limitations. This would allow the operators more time before selecting target elevations. This would allow for more climatological data to be considered to ensure that optimum reservoir operations are realized.

RECOMMENDATION 1.9: Implement EPA's 2021 TMDL for temperature in the Columbia and Lower Snake Rivers.

EPA's TMDL identified that the Federal Columbia River Power System is a primary source of thermal impairment. Dam impoundments have significantly contributed to warming of the Columbia and Snake Rivers in the summer and fall due to increased river surface area and increased time for water to travel through the reservoirs that result in increased heat inputs. Significant changes to dam operations to limit thermal impairments are expected.

RESERVOIR OPERATIONS: STORAGE PROJECTS

RECOMMENDATION 1.10: Implement modified flood control during years with lower seasonal snowpack.

Modeling has shown that modified flood control is important during low snow years when flood control is not as much an issue, but spring/summer flows are at risk from diminished runoff. During years of high snowpack, there is generally sufficient water for spring/summer migrations, but a higher flood risk that must be controlled by releasing more water during the winter. Modifying flows in low flow years allows more water to be shifted into the spring and summer and supports juvenile migration with shorter downstream travel times. A more natural or "normative" hydrograph that is more in tune with the salmon's life cycle and accommodates the coming changes to basin hydrology due to future climate change impacts. Such a change in lower Columbia River flood risk exceedance may slightly raise flood risk while still providing reasonable flood control protection at levels far below those envisioned by our Canadian neighbors who operate 40% of the water storage in the Columbia Basin.

RESERVOIR OPERATIONS: RUN OF RIVER PROJECTS

RECOMMENDATION 1.11: Operate at minimum operating pool.

Ensure that projects are operated at Minimum Operating Pool (MOP) throughout the migration season to reduce pool volumes and decrease water particle travel time which aids in decreasing migration time. A lower pool elevation creates more flow and more closely resembles a river environment.

FISH PASSAGE IMPROVEMENTS AND MAINTENANCE AT FEDERAL COLUMBIA AND SNAKE RIVER DAMS

RECOMMENDATION 1.12: Maintain and improve the existing fish passage facilities at the federal Columbia and Snake River Dams.

The Corps of Engineers recognized the need for $42 million of capability related to capital improvement needs in 2022 for fishways at the eight mainstem Columbia and Snake River dams (see also APPENDIX C).[46] However, the president's budget allocated only $3.5 million total for Corps' FY2022 capability for the Columbia and Snake River. This is the lowest amount ever requested by a president for the Corps' Columbia River Fish Mitigation program over the past 30 years. Moreover, the Corps' operations and maintenance budget for these fishways that are funded by a complex arrangement between the Corps and BPA have remained unadjusted for inflation.

The Corps' Columbia River Fish Mitigation program, its Fish Passage Operations and Maintenance program, Lamprey passage and Estuary habitat actions are guided by advice from state, tribal and federal experts operating through the following committees organized by the Corps' Northwestern Division:

- System Configuration Team (SCT)—Prioritizes capital expenditures from within the CRFM program.
- Fish Passage Operations and Maintenance committee (FPOM)—Identifies and prioritizes operations and maintenance needs at all Columbia River System projects.
- Lamprey Technical Workgroup—This workgroup has developed near term and long term for juvenile and adult lamprey passage needs at the mainstem dams.
- Expert Regional Technical Group (ERTG) Process for Columbia River Estuary Habitat—Developed evaluation criteria for funding habitat improvements in the Columbia River Estuary.

The hydropower dams require significant investment to maintain operations and functions. For some reason, the dam operators understand the need to maintain turbine maintenance and replacement yet forgo mandatory maintenance and upgrades to fishways. The annual costs to maintain the fish passage system through the CRSO as identified through these expert sources and spread over eight years, from 2023 through 2031, totals about $90 million per year.

[46] The eight dams are: Lower Granite, Little Goose, Lower Monumental, Ice Harbor, McNary John Day, The Dalles and Bonneville.

Specific actions are detailed in the following TABLE 2.

TABLE 2. Eight-Year Total Costs for Fishway Improvements, Operations and Maintenance and Related Fish Impacts Mitigation (Millions $)

Fish ladder repairs and improvements	$ 160,365
Spillway repairs and improvements	176,250
Lamprey passage	165,145
River mouth sediment and cold water refugia actions	12,000
Fish screen and juvenile bypass screen maintenance	132,785
Survival & Monitoring Studies (spill operations and turbine improvements)	50,550
Avian predation deterrents	31,200
Estuary work	6,500
Total (8-year planning budget)	**$ 734,795**

In contrast to these needs, funding for these programs has declined and is uncertain going forward. At the same time the cost of labor and materials such as aluminum and steel continue to rise. Running these dams harder for energy production while reducing fish maintenance needs is not consistent with the parity provisions of the Northwest Power Act.

3.1.2. Snake River Dam Breaching

RECOMMENDATION 1.13: Restore the Lower Snake River to a climate resilient, free-flowing river by breaching the four lower Snake River dams.

The Columbia Basin Tribes, as salmon people, have suffered tremendously from the construction and operation of dams in the Columbia River. As dams were planned and then constructed, the tribal voice of opposition was disregarded or ignored. The Tribes were told that their lost fish and fishing sites would be replaced; something that has never occurred. The Columbia's dams were literally built on the backs of salmon and tribal culture.

The Snake River Basin, because it is the largest source of spring Chinook, steelhead, and historically, fall Chinook that travel through the Tribes' treaty fishing areas on the mainstem Columbia River, has been of special significance to the CRITFC Tribes. The Snake River's four lower mainstem dams have been especially harmful in the demise of this large, productive basin's wild spawning salmon and steelhead resources. The General Council of the Umatilla Tribe and the Nez Perce Tribal Executive Committee, with responsibilities for aboriginal lands and fish resources in tributaries of the Snake River, have adopted resolutions supporting removal of the Snake River dams—the Umatilla General Council in 2021[47], and the Nez Perce in 1999.[48] In recent years, the Tribes' understanding of the permanent damage caused

[47] Umatilla General Council Resolution 21-002

[48] NPTEC Resolution NP 99-140

by these dams has received more acceptance and attention.

In March 2020, the State of Washington released, its *Lower Snake River (LSR) Dams Stakeholder Engagement Report.* The intent of the report was to capture Washington perspectives on the potential positive and negative impacts (social, economic, and environmental), as well as opportunities gained and lost, of either retaining the dams or breaching them. Section 5 in the report addressed the potential energy consequences of removing the dams and identified several questions to address in assuring that Washington state can meet its energy needs with a decarbonized power generation system as the population grows, the climate changes, and without the power from the lower Snake River dams.[49]

In the Spring of 2021, both the Affiliated Tribes of Northwest Indians and the National Congress of American Indians passed resolutions calling for bold actions to protect salmon, including restoring the lower Snake River by breaching the four lower Snake River dams.[50]

On October 15, 2021, Washington's Governor Jay Inslee and Senator Patty Murray reported that they are exploring options to breach the lower Snake River dams and replace the benefits they provide. Recognizing "the urgency of tackling this longstanding challenge as salmon runs continue to decline," they wrote, their recommendations will be finished by the end of July 2022. Before that, they plan to conduct "robust outreach" to hear from communities across the Northwest, including tribes who say their fishing rights—guaranteed by treaties—are being undermined by declining salmon runs.[51]

Moreover, Congressman Mike Simpson (R-ID) posted the following observations concerning the region's energy future without the Lower Snake River dams on his congressional web page:

- **MYTH:** The power from the four LSR dams cannot be replaced.
- **FACT:** Recent advancements in energy storage will be key to replacement power. This plan invests 10 billion dollars in firm clean power replacement such as; pump, battery storage, small modular reactor, or other technologies.
- **MYTH:** Once the dams are breached, replacement power might not be online.
- **FACT:** All replacement power must be online prior to any breaching. Also, the dam infrastructure will remain in place, only the earthen berms around the dams will be removed, so if salmon do go extinct, the dams could be restarted.[52]

This unprecedented attention and the calls for breaching the Lower Snake River dams warrants planning and accommodation by the region's utilities and energy systems' analysts. Further discussion follows.

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49 https://www.governor.wa.gov/sites/default/files/Final%20Draft%20LSRD%20Report.pdf.

50 The resolutions are set forth in **APPENDIX B**.

51 The statement laid out one potential roadmap for legislation in Congress to authorize breach that involves the Water Resources Development Act. https://www.tri-cityherald.com/news/local/article255030822.html#storylink=cpy

52 https://simpson.house.gov/uploadedfiles/myth_and_facts_.pdf.

BACKGROUND ON THE FOUR LOWER SNAKE RIVER DAMS

Lower Granite, Little Goose, Lower Monumental and Ice Harbor, the four lower Snake River dams (LSRD), were constructed between 1962 and 1975. Almost immediately after construction, declines in Snake River runs of salmon and steelhead were observed. Congressional testimony of fishery experts in 1979 led to adoption of fish provisions in the Northwest Power Act. Among other things, the Northwest Power Act was intended to forestall the need to list salmon and steelhead under the Endangered Species Act. By the mid-nineties, however, Snake River sockeye, spring/summer chinook and steelhead were listed as either endangered or threatened under the ESA. As described earlier, wild spawning runs of Snake River Chinook and Steelhead are at their lowest levels in written history. In September 2020, NOAA Fisheries observed that warming Snake River water temperatures in the section of the river impounded by the LSRD pose a catastrophic threat to Snake River sockeye salmon.[53]

The LSRD produce approximately 10% of BPA's annual energy portfolio (~900aMW) and approximately 3% of the Northwest's annual energy production from all sources.[54] A portion of the LSRDs energy capability is used as reserves to ensure BPA has enough capacity to provide power reliability for utility customers. During cold snaps or during emergency situations when energy production from other forms of generation may be negligible or unavailable, the LSRD can produce 10% of BPA's total capacity for 10 hours a day over a five-day period provided there is adequate river flow.

The LSRD each have relatively little water storage and typically operate within a limited range of forebay elevations often described as "run of river". Their power output is seasonal and weather dependent. This seasonal output generally does not align with the periods when the power is needed the most. Peak seasonal output is in the spring, whereas peak demand on the federal system is likely to occur in the late summer and winter. Due to these variations, the LSRD produce about one-third of their nameplate capacity.

TABLE 3. Lower Snake River Dam Capacity Summary

	Nameplate Capacity (MW)	20-year Average Capacity Factor (%)	In-service Year
Ice Harbor	603	34%	1962
Lower Monumental	810	34%	1969
Little Goose	810	32%	1970
Lower Granite	810	32%	1975
TOTAL	**3,033**		

[53] https://www.fisheries.noaa.gov/feature-story/warming-poses-catastrophic-threat-snake-river-sockeye

[54] The total Pacific Northwest annual energy production, including energy efficiency, has exceeded 30,000 average megawatts since 2011. https://www.nwcouncil.org/sites/default/files/2021powerplan_2021-5.pdf.

STUDIES REGARDING BREACHING THE SNAKE RIVER DAMS

The federal government has considered options for breaching the four Lower Snake River dams in three environmental impact statements (EIS), including:

- The System Operation Review EIS published in 1995,[55]
- The Lower Snake River Juvenile Salmon Migration Feasibility Study and final EIS published in 2002,[56] and
- The Columbia River System Operations EIS published in 2021.

Recognizing the threats to salmon posed by warming Snake River water temperatures, the U.S. EPA conducted modeling analyses to consider the temperature effects of removing the LSRD. EPA found that:

- The free-flowing scenario results in a significantly cooler Lower Snake River by 1–2°C during the period when the Snake River currently typically exceeds 20°C (mid-July—mid September).
- The free-flowing scenario significantly reduces the number of days that exceed a daily average of 20°C.
- The cooler daily average temperatures in the summer and fall under the free-flowing scenario as noted above will result in cooler temperatures for a few migrating adult sockeye in July, for a significant number of adult steelhead in July, August, and September, and for a significant number of adult fall Chinook in August and September.

In 2018, Energy Strategies, LLC was commissioned by the Northwest Energy Coalition to conduct a study to test the technical feasibility of replacing the LSR Dams with a clean energy portfolio while ensuring the reliability, stability, and adequacy of the Northwest power system. The study utilized a suite of analytical tools familiar to energy planners in the Northwest, such as the GENESYS model that is relied upon by the Northwest Power and Conservation Council in developing its Power Plans.[57] The goal of the Energy Strategies, LLC study was to facilitate understanding around the technical feasibility of the replacement portfolios and to provide information surrounding their relative costs and potential impacts to greenhouse gas emissions in the region.[58]

The Energy Strategies, LLC study also used the Northwest Power and Conservation Council's 7th Power Plan and its Regional Portfolio Model data as the primary sources for determining the levels of energy efficiency, demand response and resource costs available to replace the LSR Dams. Key findings from the report included:

1. Dam replacement using clean resources is achievable from both a technical planning regional reliability/adequacy standpoint and from a resource availability standpoint.

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[55] https://www.bpa.gov/efw/Analysis/NEPADocuments/nepa/System_Operation_Review/pdf/FinalEISSummary.pdf. The EIS System Operation Strategies considered "drawdown" of the lower Snake River dams to natural river levels on a temporary (SOS 5b) and permanent basis (SOS 5c).

[56] https://www.nww.usace.army.mil/Library/2002-LSR-Study/

[57] The GENESYS model was developed to simulate the operation of the regional power system in order to assess the adequacy of the power supply. GENESYS is also used to assess the impacts and costs of non-power related constraints placed on the operation of hydroelectric facilities. The majority of these constraints are intended to protect, mitigate and enhance fish and wildlife populations that could be threatened by the hydroelectric system. https://www.nwcouncil.org/energy/energy-advisory-committees/system-analysis-advisory-committee/genesys-–-generation-evaluation-system-model

[58] https://nwenergy.org/wp-content/uploads/2018/04/LSRD_Report_Full_Final.pdf.

2. The total costs of the clean energy replacement portfolios, particularly the balanced portfolios that include both new wind/solar and demand-side measures, are relatively small compared to the total projected costs of the Northwest power system.
3. If clean replacement portfolios are implemented in conjunction with GHG reduction policies, substantive net reductions in emissions are possible.
4. The clean replacement portfolios met reliability criteria under peak summer and winter conditions and did not create any new reliability issues.
5. The replacement portfolios provided the region with enhanced resource adequacy compared to the LSR Dams.

The Council is now on the verge of adopting its 8th Power Plan. Energy resource costs and markets have changed dramatically since the 7th Power Plan was adopted.[59] Key differences between the 7th and 8th Power Plans include significant decreases in wind and solar renewable resource costs **(TABLE 4)**. These differences are likely to make replacing the energy and capacity provided by the four dams even more feasible.

For example, the 2018 Energy Strategies, LLC study considered a low-cost sensitivity alternative that anticipated installed capital cost declines would occur for certain power resources by 2026 for wind (–20%), solar (–30%), Li-ion batteries (–40%) and conservation (–20%). The sensitivity study showed reductions in total annual costs from 2% to 17% for the portfolios needed to replace the energy provided by the lower Snake River dams. The costs of wind and solar forecasted in the 8th Power Plan have decreased by almost twice the cost decreases used in the Energy Strategies sensitivity study. As CRITFC recommended to the NPCC, the 8th Power Plan should consider a future Northwest energy scenario where the LSRD are breached.[60] Other planning in the Pacific Northwest such as the Washington EFSEC's Transmission Corridor Planning Workgroup,[61] Northern Grid,[62] the Oregon PUC's distribution system planning docket[63] and the Northwest Power Pool's Resources Adequacy studies[64] should also address these scenarios in their analyses.

TABLE 4. Key Differences Between the 7th and 8th Power Plans

Resource	Seventh Plan (2016$/kW)	Eighth Plan (2016$/kW)	Trend
Onshore Wind	$2,382	$1,450	47% decrease
Solar PV	$2,566 $1,792 (low cost)	$1,350 (E. Cascades); $1,465 (W. WA)	60% decrease

[59] "Never in the 40-year history of the Northwest Power and Conservation Council have we seen such dramatic changes in the future power supply than what the Draft 2021[8th] Power Plan outlines." https://www.nwcouncil.org/sites/default/files/2021-6.pdf.

[60] See CRITFC's letters to the NPCC regarding the development of its 8th Power Plan, posted at https://critfc.org/tribal-treaty-fishing-rights/policy-support/public-documents/?topic_area=energy-vision.

[61] https://www.efsec.wa.gov/energy-facilities/transmission-corridors-work-group

[62] https://www.northerngrid.net

[63] https://www.oregon.gov/puc/utilities/Pages/Distribution-System-Planning.aspx

[64] See **APPENDIX I** setting for CRITFC's comments to the Northwest Power Pool.

3.1.3. Additional Long-Term Actions for the Columbia River System

RECOMMENDATION 1.14: Future energy planning should recognize that, in the long-term, hydro actions will continue to evolve.[65]

As the region and the West look forward to their energy futures, this planning should enable, and certainly not foreclose the actions described below so that they are available to address the needs of key species.

- Move the Corps of Engineers' annual systemwide "Control flow" for the Columbia River at The Dalles to 450,000 cfs (bankfull) and gradually ramp up to 550,000 cfs (flood-flow) to benefit juvenile salmon, steelhead and lamprey migrating during Spring and early summer periods, as well as creating suitable spawning conditions for sturgeon.
- Secure three to five million acre-feet of storage in Canadian Columbia Basin reservoirs to be used for salmon migration support.
- During dry years (*i.e.*, years with low snowpack) when downstream flood risk is diminished, implement ecological rule curves that store additional water in the upper reservoirs (primarily at Grand Coulee) to preserve adequate flows for migrating juveniles and adults during the spring and summer months.
- Improve adult and juvenile passage for Pacific Lamprey at the dams.
- Develop a long- and/or short-term sediment budget model throughout the Columbia River Basin with specific focus on the Cold-Water Refuges (CWR) along the river.
- Maintain energy reserves to meet fish and wildlife obligations. Increasing planning reserve margins, reducing peak loads, storage, demand response, and increasing energy efficiency and renewable resource development will all help reduce risks to fish and wildlife and the region's economy during low-water years. Until these provisions are in place, the region may need to rely on existing thermal resources to avoid another year like 2001. We note that several natural gas-fired resources have been built during the past 20 years and there may be some potential to serve some of them with renewable natural gas. CRITFC strongly supports shutting down all fossil fuel resources to address the climate crisis; however, ensuring robust fish and wildlife protections during a dry-water year is a higher priority than short-term operations of thermal resources in the near term needed to maintain fish and wildlife protections.

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[65] A comparison of Fish Operations Plans (FOPs) from the Corps of Engineers for the last 15 years is illuminating. See http://pweb.crohms.org/tmt/documents/fpp/ for annual FOPs (included as appendices to their annual Fish Passage Plans). For instance, in 2005, under a Court Ordered Spill Injunction, spring spill shifted to 24-hour spill at all eight of the CRS projects, and spill was added in the summer at the Snake River projects (http://pweb.crohms.org/tmt/documents/fpp/2006/sections/E_BIOP_Spill.pdf). This was a major change in operations that lasted for 10 years. In 2017, another Court Ordered Injunction increased the 24-hour spill to the 115% forebay and 120% tailrace maximum spill limits set out by state Total Dissolved Gas (TDG) Waivers (http://pweb.crohms.org/tmt/documents/fpp/2017/final/FPP17_AppE.pdf). Under the Flex Spill Operations Agreement, finalized in 2019, spill was no longer tied to forebay monitors but allowed up to tailrace limits (at most dams) for 16 hours per day and then reduced to the performance spill levels for 8 hours (http://pweb.crohms.org/tmt/documents/fpp/2019/final/FPP19_AppE.pdf). In spring 2020, the tailrace TDG limit was increased from 120% to 125% at most dams. http://pweb.crohms.org/tmt/documents/fpp/2020/final/FPP20_AppE_FOP.pdf. The Flex Spill Operations Agreement expired when the 2020 BiOp for the CRSO was finalized, however the Proposed Action and BiOp have—at least initially- adopted the spill operations outlined in the Flex Spill Agreement with spill levels now caped at 125% TDG as measured by the tailrace monitors. However, future operations of the CRS projects are subject to modification through adaptive management, potential litigation outcomes, and ongoing negotiations of new Accord agreements.

3.2 Columbia River Treaty

RECOMMENDATION 2

The United States and Canada should include direct participation of the 15 tribal sovereigns in the U.S. portion of the Columbia Basin in negotiations to modernize the Columbia River Treaty in ways that restore and maintain ecosystem functions compatible with healthy and harvestable treaty-protected resources. The parties should integrate other energy resources into the treaty negotiations that have the potential to reduce carbon emissions, improve renewable resource integration while protecting fish impacted by the energy systems of the two countries.

RECOMMENDATION 3

The Corps of Engineers should conduct a comprehensive study of flood risk in the Columbia Basin; and the need to make regional decisions on balancing flood risk with multiple purposes of the system, including ecosystem function and effects on fish and wildlife.

The Columbia River Treaty between the United States and Canada in came into full force and effect on September 16, 1964.[66] The dual Treaty purposes were to optimize hydroelectric power production through the U.S. system and to provide coordinated flood control. Ecosystem function, including protection of fish and wildlife and other tribal trust resources are not currently a purpose of the Columbia River Treaty. The Treaty has no end date but may be terminated by either party providing a ten-year notice of an intent to terminate the Treaty.

The United States and Canada initiated formal negotiations to modernize the Treaty in May 2018. U.S. negotiators are being guided by the U.S. Entity Regional Recommendation for the Future of the Columbia River Treaty after 2024 (Regional Recommendation), submitted to the U.S. Department of State on December 13, 2013, as well as by specific authorities developed by the U.S. Department of State as provided under statute. Canadian negotiators are being guided by the Columbia River Treaty Review B.C. Decision (B.C. Decision). Both documents recognize the need to address ecosystem

[66] The U.S. Senate ratified the Treaty in 1961 but Canada did not ratify the Treaty until 1964, after an exchange of diplomatic notes on January 22, 1964, that provided how the Treaty's flood control provisions were to be implemented by the parties and that laid out the terms for the sale of the first 30 years of Canada's share of the downstream power benefits (Canadian Entitlement). These terms were adopted as part of the Treaty by protocol, which also included the specific details of the sale of the Canadian Entitlement. In 1963, Canada and the Province of British Columbia entered into an agreement regarding the implementation of the Treaty by the Province, that recognized that all the benefits of the Treaty were to be retained by the Province and that required the concurrence of the Province on any Treaty-related actions by Canada, including Treaty termination.

function under the Treaty. Both documents also predate the dramatic changes in renewable resource portfolios forecasted to occur throughout western North America by the WECC.

If the Columbia River Treaty is not modernized through negotiations before September 16, 2024, Canada will no longer be obligated to provide coordinated flood control management and protection to the U.S. After 2024, the U.S. will have to call upon Canada to provide flood control, which Canada interprets the Treaty to first require the United States to use all the storage facilities in the United States before calling upon any flood control relief from Canada. The U.S. will also have to pay Canada for operational and opportunity costs of providing flood control services.

The Canadian view, requiring that the U.S. first utilize all of its available storage, would put at risk several dam and reservoir operations developed to integrate ecosystem function into U.S. hydropower operations that would substantially impact fish and wildlife resources beginning in 2025. Importantly, Canada also believes that, pursuant to Treaty terms, the U.S. could not call upon Canada for this type of flood control assistance after September 2024 unless the flows at The Dalles Dam were expected to exceed 600,000 cubic feet per second (cfs); the U.S. Army Corps of Engineers notes that flood damages to areas below The Dalles Dam begin when flows exceed 400,000 cfs and that substantial damages occur downstream when flows exceed 600,000 cfs.

An analysis prepared by the U.S. Entity (BPA and the Corps of Engineers), working with other federal agencies, the Columbia Basin tribes, and the States of Oregon, Washington, Idaho, and Montana (Northwest States), indicates that this change in flood control operations at several dams and reservoirs throughout the basin would have significant effects on resident fish and cultural resources in the Grand Coulee, Hungry Horse, Libby, and Dworshak reservoirs. Refilling the deep draw downs in theses reservoirs will also further reduce the spring freshet for salmon migration. The Columbia Basin Tribes Coalition[67] is concerned about the adverse impacts to resident fish and tribal resources in these reservoirs and reductions in migration flows for salmon and steelhead.

It is also possible that the flood control operations could change operations of the upper Yakima River storage dams (including Keechelus, Kachess, and Cle Elum lakes), and other storage reservoirs that could be drawn down significantly in late winter to early spring timeframe to prepare for the spring runoff. These potential operational changes would need to be implemented at all reservoirs throughout the Columbia River basin above The Dalles Dam before the U.S. could call upon Canada for flood storage operations.

The Columbia Basin Tribes Coalition developed a common views document in 2010 and the fifteen Columbia Basin tribes are working together to avoid these damaging changes in flood control operations. During the development of the Regional Recommendation the Columbia Basin

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[67] The Burns Paiute Tribes, the Coeur d'Alene Tribe, the Confederated Salish and Kootenai Tribes of the Flathead Reservation, the Confederated Tribes of the Colville Reservation, the Confederated Tribes of the Umatilla Indian Reservation, the Confederated Tribes and Bands of the Yakama Nation, the Confederated Tribes of the Warm Springs Reservation of Oregon, the Cowlitz Indian Tribe, the Kalispel Tribe of Indians, the Kootenai Tribe of Idaho, the Nez Perce Tribe, the Fort McDermitt Paiute Shoshone Tribes, the Shoshone Bannock Tribes of the Fort Hall Reservation, the Shoshone Paiute Tribes of the Duck Valley Reservation, and the Spokane Tribe, with support from the Columbia River Inter-Tribal Fish Commission, Upper Columbia United Tribes and the Upper Snake River Tribes tribal organizations, have been working together to consider the effects and alternatives related to the Columbia River Treaty. In June 2018, the Yakama Nation announced that it would be speaking for itself on all issues related to the Columbia River Treaty from that point forward.

tribes worked with the U.S. Entity and Northwest states to explore ways to modify the treaty to improve conditions for salmon, steelhead, and resident fish and reduce flood control costs. The Columbia Basin tribes continue to coordinate with the U.S. negotiating team on these issues. Before the treaty's 50-year control of the river gives way to a new era, the progressive Regional Recommendation, which reflects the evolution of societal values that have occurred since 1964, must provide the framework upon which the negotiations with Canada proceed to conclusion to modernize the Treaty. A modernized treaty should provide equally for ecosystem requirements, hydropower operations and flood-risk management. Equal consideration of improved spring migration of salmon, seasonal flushing of the estuary, resident fish requirements and salmon passage at all historic locations are all needs of the Columbia River basin that should be included in a new treaty.[68] The elements of this Energy Vision are intended to complement a modernized Columbia River Treaty.

The original treaty negotiations focused on economic issues associated with sharing the several hundred megawatts of electricity generated through coordinating the Columbia River's flow at the border to optimize power generation through the U.S. hydropower system. These benefits were calculated almost 60 years ago, and the energy situation has changed significantly. Some U.S. utilities argue that they have fully paid Canada for the benefits. Canada might argue that a number of U.S. commitments in the treaty, including several large reservoirs and the construction of many nuclear and coal plants, did not occur.

While determining how—or if—these downstream power benefits of the Treaty should continue under a modernized Treaty these issues should not be the primary focus of the talks.[69]

Rather, it is time to expand the discussion to address the new realities in the west coast energy system. The Council projects that 14,000 megawatts of renewable resource generation will be built in the Northwest over the next 20 years and there are opportunities to coordinate and integrate those resources that provide win-win outcomes. For example, our analysis shows that 1-million-acre feet (MAF) of Mica storage capacity in Canada would firm 4,782 megawatts of wind energy over one year. The current treaty does not address these integration opportunities.

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[68] See **APPENDIX C**.

[69] Canada's 50% share of these benefits is known as the Canadian Entitlement.

The current treaty also does not address all the storage in British Columbia. For example, the W.A.C. Bennett Dam and Williston Reservoir on the Peace River was completed in 1968 and added 32 MAF of storage to the region—approximately 40% of total storage.

The negotiations should explore win-win options to coordinate generation and use storage to integrate the major renewable resource development that is projected over the next 20 years. The negotiations need to integrate the 50 MAF of Canadian storage in the Columbia and Peace River systems into the modernized treaty. Clearly, this will benefit the Canadians financially and could provide major energy, environmental, and operational benefits in the Pacific Northwest.

Taking a big picture view of the coordination of all the major hydroelectric dams and storage reservoirs in Columbia Basin should lead to the following priorities for a modernized treaty: (1) treaty rights of all Columbia Basin tribes and First Nations, (2) flood control, (3) ecosystem function, (4) capacity, and (5) energy. CRITFC will continue to consult with Indigenous Nations in Canada and the US State Department on these issues.

3.3 Reduce Peak Demand

Controlling energy demand during times of peak energy usage needs to be a priority for the region. Electric supplies must meet energy demand every second of the day. Electricity demand peaks in the mornings as individuals and business begin their day to heat or cool buildings and in the late afternoons when people come home and need to heat or cool their houses, prepare dinner, and turn on other appliances. These daily peaks get larger on very cold or very warm days because it takes even more energy to heat and cool buildings.

Cutting peak demand will reduce damage to salmon and steelhead. River fluctuations disrupt migration and increase exposure to predators. Reducing peak demand will also reduce greenhouse gas emissions from thermal power plants.

There are quantifiable benefits to consumers from reducing peak loads. For the electrical system, lower demand on peaks translates into fewer capital resources that are needed to serve loads. The grid can serve the same total energy needs with fewer generating plants and a smaller investment in new transmission and distribution lines over time if peaks are lowered. Line losses and ancillary services can also be reduced with lower demand.

APPENDIX E describes the high cost of the transmission and distribution system associated with meeting peak demand. For example, serving the highest 600 hours during a year (out of 8,760 hours) is estimated to cost between $0.50 and $1 per kilowatt hour, compared to the average costs residential customers pay of about $0.08 to $0.12 per kilowatt hour. These high transmission and distribution costs get averaged into everyone's electric bill.

The analysis of the cost effectiveness of energy efficiency, storage, and other demand response actions should incorporate more accurate costs for the transmission and distribution systems needed to meet peak loads. The Council's analysis for the draft 8th Power Plan appears to use an average rate for transmission in the region of $31 per kilowatt per year and the average distribution cost of $26 per kilowatt year[70] in calculating the benefits of deferring construction. CRITFC's analysis estimates that the transmission and distributions costs of serving the top 600 hours (out of 8760 per year) is between $80 and $100 per kilowatt year.[71] Using these higher costs when calculating the value of deferring peak loads would likely improve the cost effectiveness of actions that reduce peak loads.

Reducing peak demand would also defer or eliminate the need for some new transmission and distribution systems. For example, BPA and four Northwest investor-owned utilities spent more than $8 billion on transmission and distribution systems over the past five years. Future expansions will add significant costs and can adversely affect sensitive resources along power line routes. See SECTION 3.10 and APPENDIX E for more information on transmission and distribution costs.

As discussed above, the region is currently valuing the "flexibility" of the hydroelectric system at zero, but we know the changes projected for the system will have devastating effects on fish and wildlife. The evaluation of programs to reduce peak demand must address these impacts on fish and wildlife and other tribal resources.

Adopting technologies that allow for peak load control may have significant advantages for fish passage. Once in place to control peak loads, it is a small step to use them to shape loads on a continual basis. Shaping loads could then translate into reducing energy demand pressures that compete with salmon and steelhead.

By 2030, according to one estimate, the United States will have nearly 200,000 megawatts of cost-effective load flexibility potential, equal to 20% of estimated U.S. peak load. That is three times the existing demand response capability, with savings for consumers from avoiding utility system costs estimated at $15 billion annually. This flexibility, largely by use of technology for managing energy use in buildings, can help cost-effectively address several grid challenges, from growth in peak demand, to higher levels of variable renewable energy generation, to increasing electrification of transportation and other loads.[72]

As energy systems acquire the general ability to control loads, we can envision a time when loads can be shaped to harmonize with electricity supplies and the hydro system configurations and operations needed for fish and wildlife.

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[70] Northwest Power and Conservation Council memorandum *Updated Transmission and Distribution Deferral Value for the 2021 Power Plan*, March 5, 2019.

[71] Draft *Energy Vision for the Columbia River Basin,* Appendix E.

[72] Hledik, R., A. Faruqui, T. Lee, and J. Higham. 2019. The Brattle Group. "The National Potential for Load Flexibility: Value and Market Potential Through 2030." https://brattlefiles.blob.core.windows.net/files/16639_national_potential_for_load_flexibility_-_final.pdf.

Several utilities have experienced flat or declining peak winter loads, while their summer peak loads have increased slightly.[73] The region needs to build on these efforts to reduce future peak loads. These efforts will reduce costs, improve salmon survival, and improve the reliability of the electric system.

3.3.1. Energy Efficiency Reduces Peak Demand

RECOMMENDATION 4

The Council, BPA, and utilities should include the peak savings and reductions in transmission and distribution benefits in calculating the capacity value of energy efficiency programs.

Energy efficiency programs continue to be among the lowest-cost ways to meet future energy needs. They have the added benefit of reducing peak demand. Extensive regional experience shows that balanced energy efficiency portfolios disproportionately save electricity during peak periods. A well-insulated home or office requires less heat in the winter and less air conditioning in the summer. Energy efficiency is "fish friendly". It is the energy resource that has the least potential to damage tribal resources. **TABLE 5** shows the NPCC analysis of the energy efficiency savings between 2016 and 2019. It shows that the total savings were 857 average megawatts. These programs resulted in 1,683 megawatts of peak savings in the winter and 1,042 megawatts in the summer.

TABLE 5. Capacity Savings by End Use—All Sectors Combined

	Sum of Winter MW Savings	Sum of Summer MW Savings
Lighting	698.06	445.43
HVAC	519.19	145. 70
Whole Bldg/Meter Level	185.24	133.75
Unknown	59.56	47.57
Process Loads	47.83	49.15
Electronics	45.71	37.14
Water Heating	44.68	25.12
Refrigeration	40.84	44.73
Motors/Drives	22.12	21.13
Compressed Air	14.88	14.77
Utility Transmission System	1.62	1.57
Food Preparation	1.31	1.23
Facility Distribution System	0.97	1.00
Utility Distribution System	0.67	2.91
Irrigation	0.60	70.97
Grand Total	**1,683.28**	**1,042.17**

These programs have the added benefit of matching electric energy growth. As the number of new homes and business are built and new efficient appliances are added, the energy and capacity savings increase.

The Council's draft 8th Power Plan assumes a total additional conservation potential of 5,103 average megawatts in 2041 that "saves 9,105 megawatts of summer peak and 8,511 megawatts of winter peak."[74]

The Lawrence Berkeley Laboratory collected data on costs, energy savings and peak demand

[73] For more information, see **APPENDIX E**.

[74] https://www.nwcouncil.org/2021powerplan_conservationpotential.

savings for electricity efficiency programs for 36 investor-owned utilities and other public agencies in nine states (Arizona, Arkansas, California, Colorado, Illinois, Massachusetts, Maryland, New York, and Texas) for 2014 to 2017.[75] The savings during the study period averages $0.029/kilowatt-hour (kWh) and varies by a factor of three ($0.013/kWh to $0.039/kWh) across the nine states. The report states:

> *Based on this initial study, electricity efficiency programs appear to be a relatively low-cost way for utilities to meet peak demand, compared to the capital cost of other resources (Lazard 2018; EIA 2019) that can be used to meet peak demand. However, many energy efficiency technologies, such as more efficient light bulbs, are "passive" and are not dispatchable. In such cases, efficiency resources do not provide the same services as a natural gas peaking turbine, making comparisons between these resources complex. At the same time, our results suggest that electricity efficiency programs that reduce peak demand merit strong consideration by utilities and regional grid operators. Further, "active" efficiency measures such as lighting controls enable active management of efficiency resources, offering additional grid services.*

These cost-effectiveness calculations should also consider the very high costs of transmission and distribution systems that serve these peak loads as discussed above and in SECTION 3.10 and APPENDIX E.

3.3.2. Using Pricing to Reduce Peak Loads

RECOMMENDATION 5

Northwest public utility commissions should implement time-of-use rates to send an appropriate price signal that captures the dramatically different costs of using electricity during different times of the day.

More must be done to provide consumers with an accurate price signal for the cost of electricity at different times of the day and different months of the year. CRITFC calls on Northwest utilities and utility commissions to implement time-of-use pricing for all consumers based on the total costs of serving electricity needs.

Currently, all commercial, industrial, and agricultural customers served by investor-owned utilities in California are required to be on a time-of-use plan. Residential customers can choose to be on a time-of-use plan, by contacting their utility. The California Public Utility Commission states:

[75] https://emp.lbl.gov/publications/peak-demand-impacts-electricity.

If customers have energy usage that can be shifted from peak hours to off-peak hours, they may be able to reduce their energy bill by switching to a time-of-use rate plan. For example, customers could run large appliances like dishwashers and washing machines at off-peak hours. Electric vehicle owners may also benefit from switching to a time-of-use rate plan if they charge their vehicles overnight.

According to the California Public Utilities Commission, time-of-use pricing encourages the most efficient use of the electric energy system and can reduce the overall costs for both the utilities and customers by sending prices signals about the actual cost to serve loads at different times. Time-of-use rates vary according to the time of day, season, and day type (for example, weekday or weekend/holiday). Higher rates are charged during the peak demand hours and lower rates during off-peak (low) demand hours. In California, rates are also typically higher in summer months than in winter months. The California Independent System Operator has prepared a detailed analysis of the time of use periods in California.[76] The California PUC states: "This rate structure provides price signals to energy users to shift energy use from peak hours to off-peak hours."[77]

This time-of-use pricing should also incorporate the high costs of transmission and distribution to serve peak loads. This issue is discussed in more detail below.

Sending a clear price signal about the true costs of meeting peak loads will reinforce the recommendations on demand response, storage, and other strategies discussed below.

3.3.3. Demand Response and Load Management

Integrating renewable resources with the region's electricity needs will require better management of electricity loads. This section describes several important actions.

LOAD MANAGEMENT

RECOMMENDATION 6

Utilities should use demand response to manage system loads, reducing peak loads, ensuring reliability by encouraging customers to reduce demand during peak periods or shift loads from peak to off-peak hours.

Utilities and BPA should pursue actions to manage loads by shifting them to times when renewable power is available and to minimize impacts on fish and wildlife. These actions will reduce costs and environmental impacts.

The Council's 7th Power Plan (2016) identified significant potential to reduce or shift peak demands. It found:

The Seventh Power Plan assumes the technically achievable potential for demand response in the region is over eight percent of peak load during winter and summer peak periods by 2035. This assumption is based on the Demand Response Program Potential Study commissioned by the Council and feedback from regional stakeholders. This figure represents approximately 3,500 megawatts of winter

[76] http://www.caiso.com/market/Pages/ReportsBulletins/RenewablesReporting.aspx.

[77] California Public Utilities Commission, see https://www.cpuc.ca.gov/general.aspx?id=12194.

peak load reductions and nearly 3,300 megawatts of summer peak load reductions by the end of the study period. In addition, the study identified additional potential for summer and winter demand response that could be available by the end of the study period to provide for load and variable generation balancing services.[78]

The Council's draft 8th Power Plan significantly reduced the estimates for demand response, primarily because it was not as cost effective as renewable resources.

The Council recommends utilities examine two demand response products: residential Time-of-Use (TOU) rates and Demand Voltage Regulation (DVR) as a means to offset the electric system needs during peaking and ramping periods and to reduce emissions. A given utility's time of need may differ from the region's, but these products are likely still part of a cost-effective strategy. Our assessment shows about 520 megawatts of DVR and 200 megawatts of TOU available by 2027.[79]

As discussed elsewhere, the flawed assumption that the hydroelectric system can integrate all the new renewable resources at low or no cost creates an artificially low cost that crowds out resources like demand response. The analysis of these measures should fully consider the environmental benefits and significant cost savings from reducing the need for transmission and distribution to serve peak loads. Including an accurate accounting of the environmental impacts associated with the "steel in the ground" these costs of renewable resource and transmission construction is likely to make more demand response and related measures cost effective. Viewed from a broader perspective, the federal and state environmental policies, such as carbon reduction and endangered species preservation, are not limited by cost-effectiveness thresholds.

CRITFC urges the Council to expand demand voltage reduction and time of use programs and consider other demand response programs as alternatives to batteries or other storage devices. For example, innovators like OhmConnect are marketing their free demand response assistance as a way of reducing energy blackouts in California.[80]

Utilities should pursue demand response in residential and commercial buildings and other sectors. For example, Idaho Power and PacifiCorp are running demand response programs for air conditioning cycling and irrigation pumping. These programs are designed to reduce summer peak demands.

ELECTRIC VEHICLES

RECOMMENDATION 7

Automobile manufactures should include systems that allow electric vehicles to schedule charging during off-peak periods.

Electric cars and plug-in hybrid cars should be a win-win-win for consumers, the environment, and salmon. Electric vehicles have very low operating and maintenance costs, reduce greenhouse gases and other air pollution, and reduce dependence on foreign oil. If owners charge car batteries at times that help integrate renewable resources and improve salmon survival the region can achieve these benefits.

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[78] https://nwcouncil.org/7thplan, page 14–2.

[79] Draft 2021 Power Plan, page 6–41.

[80] https://www.ohmconnect.com/about-us.

Auto manufacturers should provide scheduling software that can control when the cars charge and promote its use (these systems are already standard on some electric vehicles). If timers are not incorporated and used, drivers might start charging when they get home from work and add to peak energy demand. This would make things worse for consumers, the power system, and salmon.

RECOMMENDATION 8

Utilities should integrate electric vehicle charging and batteries into the power system to reduce costs to consumers and the power system and improve salmon migration.

Utilities should install smart meters that would charge electric vehicles when there is low-cost surplus power and use electricity from those vehicles' batteries during peak periods. In these "vehicle to grid" systems, a electric vehicle owner could get a discount on the electricity, and this could be a cost-effective way to meet peak and provide storage at a lower-cost than utility-scale batteries.[81] This approach could also reduce the need for new transmission and distribution lines. These efforts will require improvements in information sharing so charging could be scheduled during the optimum time to reduce environmental impacts.

Electric vehicles should also be integrated with on-site solar systems to charge vehicles while the sun is shining and use their batteries when the sun goes down or during extended shortages. For example, the 2022 Ford F-150 Lightning battery could power an average home for about three days.[82]

RECOMMENDATION 9

BPA and utilities should work to improve the efficiency of electric vehicles.

An analysis by Amory Lovins concludes:

> *Efficiency gains achievable by integrative design of whole light-duty vehicles can be severalfold larger, yet cheaper, than those predicted by canonical incremental technology-by-technology analyses. This means that US and international efficiency standards rest on overly conservative analyses; electrification can be cheaper and faster than conventionally assumed; and the efficiency potential predicted by groups like the US National Research Council and assumed in climate-mitigation assessments need major revision, aided by evaluation processes that better assess whole-vehicle design and early signals from concept vehicles.*[83]

Current electric vehicles have high EPA miles per gallon (electric equivalent) ratings compared to internal combustion engines. For example, a Tesla Model 3 has a combined

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[81] Clean Vehicles as an Enabler for a Clean Electric Grid: https://iopscience.iop.org/article/10.1088/1748-9326/aabe97.

[82] https://www.motortrend.com/news/2022-ford-f-150-lightning-electric-truck-charging-generator-power/

[83] Lovins, A., "Reframing Automotive Fuel Efficiency," 2020, https://doi.org/10.4271/13-01-01-0004.

rating of 142 MPGe and a Hyundai Ioniq is rated at 133 MPGe.[84] Increasing the efficiency several fold would stimulate the adoption of these vehicles and reduce impacts on the electricity system.

HOT WATER HEATERS

RECOMMENDATION 10

The Council, BPA, and utilities should fund the incremental costs of heat pump water heaters to stimulate the adoption of this technology.

Heat pump water heaters are more efficient than conventional systems and provide both energy and capacity savings in new houses. The conversion of existing houses to heat pump water heaters will also provide benefits. The Council's 7th Power Plan estimated that cost-effective conversions from electric resistance to heat pump water heaters would reduce peak demands by 1,250 megawatts during winter (January) and just over 1,850 megawatts in summer (August) by 2035. These systems come with built-in demand reduction capability to help reduce peak loads.

Utility incentive programs would increase market penetration and likely drive down costs. This was the experience with "new technology" such as six-inch wall insulation and R-50 windows in the 1st Power Plan in 1983. BPA and utilities paid the added costs of these measures, suppliers started stocking them, manufactures mass produced them, subcontractors learned to install them, and the costs came down.

RECOMMENDATION 11

Utilities and BPA should develop and fund programs to schedule when water heaters operate.

Time-of-day water heating technology is commercially available. Water pre-heated during the middle of the night, can last through the morning peak use period. This technology can be used in today's hot water heaters, and can be made more effective in replacement tanks, by increasing the size of the water tanks. More sophisticated and easy to use demand-response enabled equipment is also coming onto the market, thanks to state-level standards passed in Oregon and Washington for CTA-2045 compliant water heaters for the residential market. To get the benefits of the peak reduction potential, however, utilities will need to develop customer-centric demand response programs.

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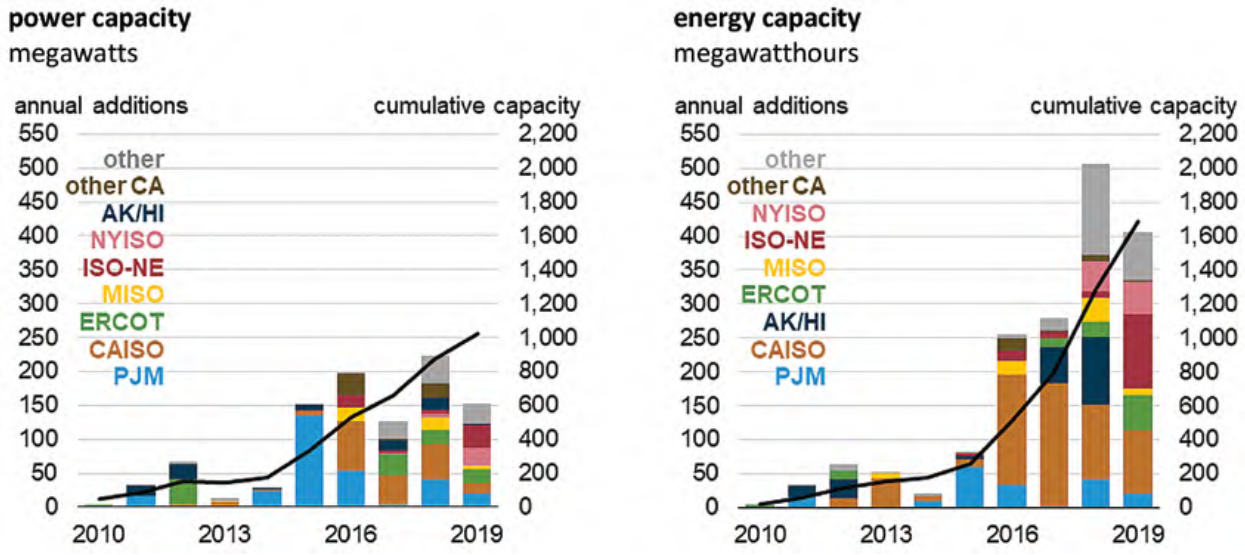
[84] https://www.fueleconomy.gov/feg/evsbs.shtml.

FIGURE 11. Large-Scale Battery Storage Capacity by Region (2010–2019)



Source: U.S. Energy Information Administration, 2019 Form EIA-860, *Annual Electric Generator Report*

3.3.4. Increase Electricity Storage

Integrating renewable resources with the region's electricity needs will require significant energy storage. This section describes several important actions to secure energy storage by fish friendly means.

UTILITY-SCALE BATTERIES

RECOMMENDATION 12

BPA and utilities should implement utility-scale battery projects.

FIGURE 11 from the U.S. Energy Information Agency shows the expansion of utility-scale batteries between 2010 and 2019.

The growth of these batteries is expanding quickly as costs come down.[85] California will have 3,000 megawatts of utility-scale batteries to store electricity to meet peak demands online by the end of 2021. These lithium battery systems store power from solar plants during the day and can provide four hours of electricity when the sun sets.

New battery technologies, such as those based on iron flow chemistry, are on the horizon that may reduce the need for the use of precious metals in energy storage.[86] An iron flow battery has six-to-twelve-hour storage cycles, are scalable to 2000-megawatt hour systems, and have a 25-year operating life.[87] These and other technologies can provide reliable energy storage and do not require the rare earth minerals of lithium batteries. The WECC projections show approximately 200,000 megawatts of solar and battery projects by 2045.

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[85] See Oregon Department of Energy 2020 Biennial Energy Report Utility Scale Storage Technology Review.

[86] https://www.bloomberg.com/news/articles/2021-09-30/iron-battery-breakthrough-could-eat-lithium-s-lunch.

[87] https://essinc.com/iron-flow-chemistry/.

These batteries could help address some reliability and renewable resource integrations issues in the Northwest. Winter peaks often last more than twelve hours and will likely require a combination of storage, improved efficiency measures, demand management, and other strategies to serve these electricity needs, especially in low-water years (please see SECTION 3.7 on Resource Adequacy).

Northwest utilities should review the experience with these batteries and begin construction of systems at strategic locations. For example, these batteries could be located near load centers or near major generation and transmission hubs to reduce the transmission and distribution costs.

The Council's draft 8th Power Plan discusses the role of batteries but does not call for actions to promote their use. It is CRITFC's understanding that the Council did not find them cost effective compared to other alternatives. As discussed elsewhere, the Council is assuming the hydroelectric dam reservoirs can be used as a huge battery at low or no costs (except to salmon). This flawed assumption prejudices the cost effectiveness of storage technologies that do not increase the mortality of migrating salmon. It is also contrary to the Northwest Power Act's mandate for due consideration to environmental impacts in the Council's energy planning processes.[88]

ON-SITE BATTERIES

RECOMMENDATION 13

BPA and utilities should implement incentive programs to expand the use of on-site batteries.

On-site generation and home and business storage systems are becoming commercially available. For example, Tesla has a Solar Roof and Powerwall system to generate and store electricity for a house. The Powerwall also tracks National Weather Service alerts for severe weather and fully charges the battery in case of a forecasted power outage. The system also has time-based controls to use stored power when grid costs are expensive and net metering credits for excess solar energy sent to the grid.

The Oregon Legislature passed a bill in the 2021 session to allocate an additional $10 million for the solar and storage rebate program to help bring down the costs of these systems. The rebates may cover up to 40 percent of the net cost for a residential system installed for a customer that is not considered low- or moderate-income, up to 60 percent of net cost for a low- or moderate-income customer, and up to 50 percent for a low-income service provider.[89] Other states should establish such programs.

FIGURE 12, prepared by Lazard Bank, shows the unsubsidized levelized cost of storage alternatives.[90]

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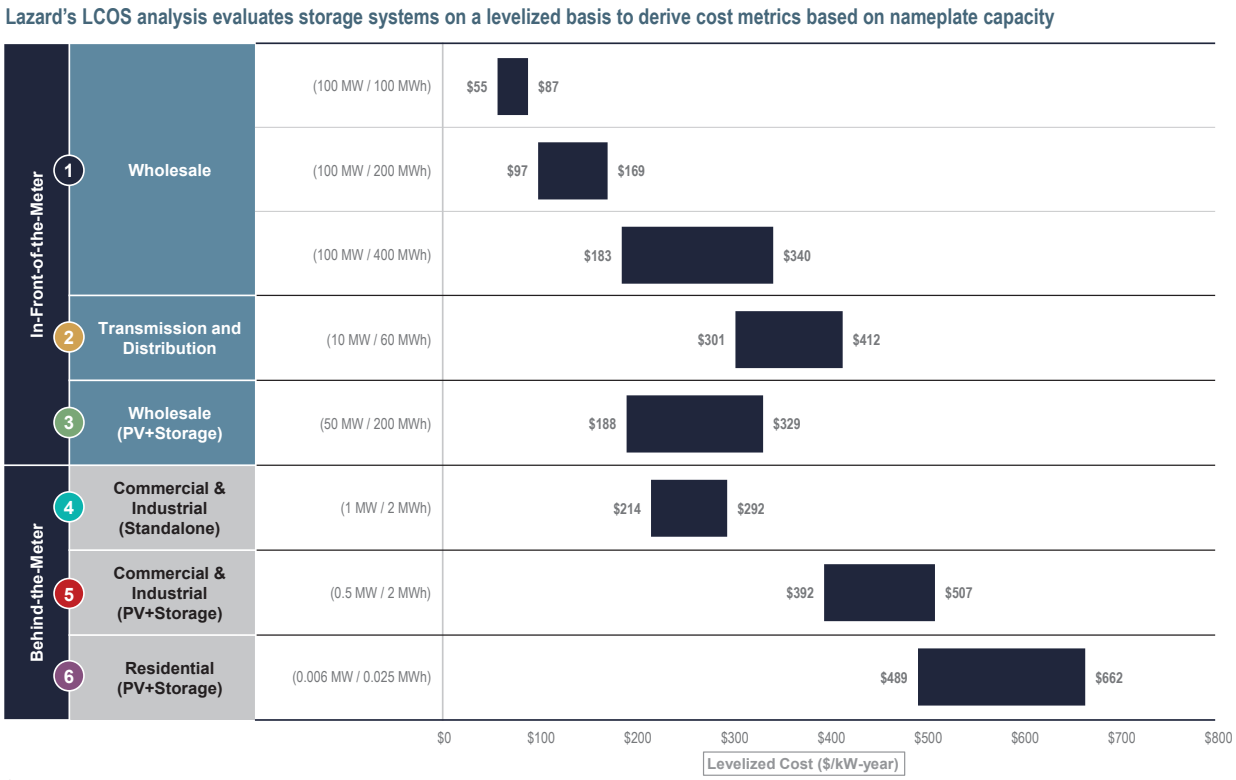
88 For more details, see CRITFC's letters to the NPCC posted at https://critfc.org/tribal-treaty-fishing-rights/policy-support/public-documents/?topic_area=energy-vision.

89 https://www.oregon.gov/energy/Incentives/Pages/Solar-Storage-Rebate-Program.aspx.

90 Lazard's Levelized Cost of Storage Analysis—Version 6.0, Lazard's Bank, 2020, page 5.

FIGURE 12. Unsubsidized Levelized Cost of Storage Comparison—Capacity ($/kW-year)



Source: Lazard estimates

SPACE HEATING AND COOLING STORED IN BUILDINGS

RECOMMENDATION 14

BPA and utilities should fund programs to reduce peak loads using the thermal mass of buildings.

Heating and cooling effects can be stored in building mass, including mass that may have been added for this specific purpose. The technique of using thermal mass (*e.g.*, properly located rocks, concrete, or other material) to store heat and cold is ancient but may be coming back in style as Northwest universities include energy efficient building design courses in their renewable energy engineering programs.[91] Adding mass to residential buildings is being tested in regional pilots. Storage of heating and cooling in buildings to meet these needs through peak periods has possibilities for around the clock applications similar to hot water storage.

Commercial buildings generally have a high mass, so they can be pre-heated and pre-cooled by using off-peak energy prior to the buildings

[91] The University of Oregon has created an Energy Studies in Buildings Laboratory with programs in Eugene and Portland employing and educating students in building designs that address climate change needs of society. See https://esbl.uoregon.edu. The Oregon Institute of Technology was the first university in the nation to offer a renewable energy engineering degree including coursework in energy efficient building design. See http://catalog.oit.edu/preview_program.php?catoid=9&poid=2030.

being occupied in the morning. The potential for saving on transmission and distribution, generation, line losses, and ancillary services is very large.

With appropriate incentives for building owners, web-based thermostat controls can enable existing buildings to store energy for heating and cooling. These controls allow a utility dispatcher to pre-heat and pre-cool buildings thereby shifting the power consumption to an off-peak period. This is an example of using the thermal mass already in the building as a storage medium. Once the platform that enables these web-based controls is in place, all energy devices using these controls could be operated for energy management purposes.

PUMPED STORAGE

RECOMMENDATION 15

The Council and utilities should not pursue pumped storage sites unless they are consistent with the siting criteria described in SECTION 3.6.

Pumped storage sites use electricity during surplus or low-cost periods to pump water into a reservoir for release through a generator to meet peak loads. These projects have experienced significant economic and environmental challenges in the past. Large reservoirs can affect tribal fish and wildlife and cultural resources. For example, a project proposed near Goldendale, Washington would affect Yakama Nation cultural, archeological, ceremonial, monumental, burial petroglyph, and ancestral use sites. The project is opposed by the Yakama Nation. Reservoirs may also create greenhouse gas emissions due to the annual cycles of decomposing of aquatic vegetation.

The NPCC has identified approximately 7,000 MW of capacity for such projects at some stage of the planning and development process; however, these projects did not appear to be cost effective. There may be some opportunities for this technology in the future, for example, improving the operations at existing sites, but any projects need to address the siting criteria discussed in SECTION 3.6 of this document.

HYDROGEN STORAGE

RECOMMENDATION 16

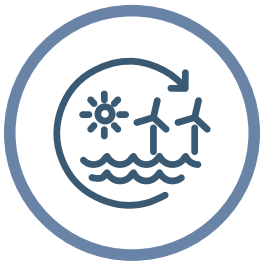
Utilities and the Council should continue to monitor green hydrogen technologies.

Renewable hydrogen can be stored, compressed for a transportation fuel, or put in a pipeline for industrial purposes. It is expensive. This technology requires low-cost electricity, water, storage facilities for the hydrogen, and energy generation or industrial use for the fuel.

Douglas County PUD is exploring a project to use surplus electricity from its hydroelectric dam to create hydrogen through electrolysis—separating hydrogen from oxygen in water using an electric current. Renewable hydrogen would be produced using a renewable resource with no carbon associated with production or consumption of the fuel. The utility is researching a 2-to-3-megawatt renewable hydrogen pilot project. In 2019, the Washington legislature authorized public utility districts to produce, distribute and sell renewable hydrogen.[92]

Electrolysis is not very efficient and therefore, may not have significant application to provide storage. Proton membrane technology is still in the early development stage. Monitoring these developments can inform future decisions on storage for renewable resources.

3.4 Energy Efficiency Resources



Energy efficiency programs reduce both peak demands and year-round energy needs. Energy efficiency has been proven as a reliable resource in the Northwest with costs that are less than half the cost of new gas-fired power plants. These programs save consumers money and reduce the emissions of pollutants that cause climate change. They are fish compatible.

Energy efficiency also reduces the region's seasonal storage needs because energy savings closely track energy demand. The "flexibility" of energy efficiency is extremely valuable. Energy efficiency programs have no adverse effects on fisheries or other tribal resources.

According to the Council, the region has saved 7,000 average megawatts since 1978 through energy efficiency programs, codes, and standards. That is enough electricity to serve more than 5 million homes. The U.S. Energy and Employment Report shows that over 100,000 people are employed in our region working with energy efficiency at utilities, the Northwest Energy Efficiency Alliance (NEEA), the Energy Trust of Oregon, state agencies, and at the many trade allies and contractors that work to implement programs and deliver efficiency services.[93]

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[92] SB 5588, Chapter 24, 2019 Laws, was signed into law on April 17, 2019.

[93] 2020 Report: https://www.usenergyjobs.org/.

These energy efficiency programs have saved northwest consumers over $70 billion dollars and those savings are growing at about $5 billion per year. The NPCC data shows that more than $8.5 billion has been spent by northwest utilities on energy efficiency programs—a significant portion of these funds were spent in the region, providing jobs and economic activity.

3.4.1. Secure All Cost-Effective Energy Efficiency.

RECOMMENDATION 17

The Council should increase the conservation targets in the 8th Power Plan to maintain at least the level of activity called for in the 7th Plan and work with BPA and utilities to try to exceed the targets.

In the draft 8th Power Plan, the Council recommends "that the region acquire between 750 and 1,000 average megawatts of energy efficiency by the end of 2027 and at least 2,400 average megawatts by the end of 2041.[94] These energy efficiency targets are significantly lower than the 7th Power Plan when the Council estimated that over 4,000 average megawatts of conservation could be acquired cost-effectively over the 20-year planning period.

One reason for the Council's decreased recommendation appears to be that solar and wind energy costs are lower than some of the energy efficiency. These lower renewable resources costs include the Council's assumption that this energy can be integrated using the regions' dams and reservoirs at little or no cost. This planning assumption is not accountable to the reality of dam operations on the Columbia River System.

It is also CRITFC's understanding that part of this reduced conservation potential is because LED lights are already in wide use and the Obama Administration adopted 49 new federal standards that are capturing some of the 7th Plan's targeted savings, so the baseline load forecast for 7th plan is lower. If this is the case, the Council should clearly communicate this change is the baseline and that new conservation measures are in addition to this baseline.

The CRITFC recommendation to maintain at least the level of activity for energy efficiency programs called for in the last plan are based on several factors:

1. We understand that the Council will be evaluating alternative river operations that we believe are likely to increase the costs of integrating solar and wind energy when compared to energy efficiency. Maintaining the program levels from the 7th Power Plan would avoid slowing energy efficiency efforts that the region may regret.
2. The Council's cost-effectiveness calculations should include the very high peak energy costs of transmission and distribution systems. CRITFC's analysis from 2013 showed the transmission and distribution costs of meeting the highest 15 percent of peak energy needs ranged from 79 cents to $1.19 per kilowatt-hour. Energy efficiency and other behind-the-meter actions avoid those high transmission and distribution costs. These

[94] Draft 2021 Power Plan, page 5–29.

avoided costs must be duly accounted for in cost-effectiveness determinations.

3. The Council notes that the energy conservation industry employees 100,000 people. Reducing these programs means downsizing this work force and reducing the number of companies providing these services when the region will likely need them in the future. Many industries are experience shortages of workers. Losing a trained work force could take years to recruit and retrain.

4. As the Council reconsiders its energy efficiency targets for the 8th Power Plan, it should assume a higher penetration rate. The 7th Power Plan assumed that only 85 percent of the cost-effective conservation will be achieved. If the region could achieve 100 percent of these savings, it would save consumers an additional $300 million per year.[95] If we assume these savings are phased in over the life of a 20-year power plan; the additional savings could total about $3 billion by 2036.

5. The Council, BPA, and utilities should include incentive programs for measures that are on the margin to stimulate new technologies. The Council and Northwest Energy Efficiency Alliance should identify promising measures and develop programs to bring down cost and increase the commercial availability. The region has had success with similar efforts where early investments reduced long-term costs.

   BPA and utilities can afford to pay the incremental costs of these marginal measures. The Northwest Power Act requires measures to be economically feasible for consumers, taking into account financial assistance from the Bonneville Power Administration and the region's utilities.

   It is important to note that BPA and utilities do not pay the full cost of the energy efficiency. Consumers usually pay a share of the costs of these programs. Building codes and appliance standards provide significant savings at no cost to utilities. A rough calculation of the costs of energy efficiency savings that were paid for by utilities is about $8 per megawatt hour[96]—a fraction of the costs of alternatives or the value of the electricity sold in the market over this period. The Council should conduct its own analysis of the utility paid costs in considering the costs and benefits of stimulating new technologies. During the first seven power plans energy efficiency was about half the cost of alternative generating resources.

6. There is a great deal of business and public interest in energy efficiency that did not exist in prior decades. Customers are asking for green certifications and business are routinely marketing products with zero-carbon footprints. Congress and the Biden Administration are considering infrastructure programs to address the climate crisis and increase funding for these programs.

7. Analysis indicates that there is likely additional energy efficiency available. We reviewed two papers that addressed this issue:

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[95] De-rating the energy efficiency that is achievable by 15 percent represents 600 average megawatts of low-cost power that were not included in the NPCC conservation targets for the Seventh Power Plan. A simple calculation of the value (marginal resource costs minus cost of conservation multiplied by 1000 average megawatts) shows that the value of this additional conservation is $300 million per year.

[96] The analysis assumes that the energy 7,200 average megawatts of savings when phased in over the past 38 years totaled savings of more than 1.2 billion megawatt hours, divided by utility spending of about $9 billion.

The first is a paper entitled: *Beyond Supply Curves*, by Fred Gordon and Lakin Garth of the Energy Trust of Oregon and Tom Eckman and Charles Grist formerly at the Northwest Power and Conservation Council. It discusses how new technologies, which are often impossible to forecast, have significantly increased the amount and reduced the cost of energy efficiency measures. Based on prior experience, the high efficiency windows in the 2005 Council Power Plan were 12 percent more efficient than the assumptions used in the Council's 1983 plan. The paper also shows how the cost of compact fluorescent lamps dropped from the $12 per bulb assumed in the 1991 plan to $3 assumed in the 2005 plan. It is likely that future innovations will continue this trend and they should be recognized in future uncertainties.

The second paper, by David Goldstein of the Natural Resources Defense Council, describes the methodologies that are "excessively conservative if the goal of policymakers is to meet aggressive climate change emission reduction goals." The paper documents the systematic biases that result in low potentials in energy efficiency. These include: 1) subjecting efficiency measures to a criterion of proof beyond a serious doubt; 2) assuming arbitrary realization factors less than 100 percent due to questions about social acceptance of energy efficiency; 3) implicit assumptions that a lack of research on the cost or feasibility of a measure means that is it excluded from a study; 4) a failure to consider system integration; 5) assumptions that once known efficiency measures are implemented, technological progress ceases and no further improvements are possible; and 6) reliance on projected costs of efficiency without looking at realized costs, which has always been lower whenever data has been available.

8. The Council projects that electrification of transportation could add 700 to 900 average megawatts of load by 2040. There appears to be significant potential for additional efficiency improvements in these vehicles (See **SECTION 3.3.3**. on Electric Vehicles).

In summary, the challenges for the region are to set realistic targets for energy efficiency and ensure the flexibility to achieve higher savings as they become available. CRITFC calls upon the region to do so.

After 40 years of experience, there are ample results in the Pacific Northwest to demonstrate that improving energy efficiency can reliably save energy. We also know that the Council's targets have been conservative. New technology has repeatedly made conservation more cost effective than estimated by the Council. Finally, the Northwest Power Act calls for energy conservation to be developed as a resource ahead of traditional resources.[97]

For all these reasons, the Council should address all the factors discussed above and increase the conservation targets to continue programs at the levels in the 7th Power Plan and work with BPA and utilities to try to exceed them.

[97] 16 U.S.C. § 839; 126 Cong.Rec. H9848 (Rep. Pritchard) ("[The Act] treats energy conservation as a resource, making it the top priority in meeting the region's energy needs. *NRIC and Yakama Nation v. Northwest Power Planning Council*, 35 F.3d 1371, 1378 (9th Cir. 1994).

3.4.2. Ensure that Utilities Achieve the Targets

RECOMMENDATION 18

The Council should monitor the implementation of energy efficiency programs to ensure that utilities meet the conservation targets.

The NPCC summary of achievements[98] shows the region ended up exceeding 6th Plan targets and is slightly ahead of 7th Plan goals—despite the impact of Covid-19 on programs. **TABLE 6** shows the region exceeded the NPCC's targets for all energy efficiency activities between 2005 and 2019.

Unfortunately, progress has slowed. The Council **FIGURE 13** shows total funding in 2021 was about $100 million per year less than in 2016 and annual savings declined from approximately 225 average megawatts in 2016 to a projected 145 average megawatts in 2021.[99]

The reductions in energy savings have been significant in the residential sector, with savings for 2016 through 2019 averaging about half the progress in 2015[100]. **FIGURE 14** from the NPCC shows the energy savings, by end use between 2010 and 2019.

FIGURE 15 shows that utilities are not meeting NPCC goals in the agricultural, industrial, and residential sector.

TABLE 6. NPCC Targets for All Energy Efficiency Activities Between 2005 and 2019

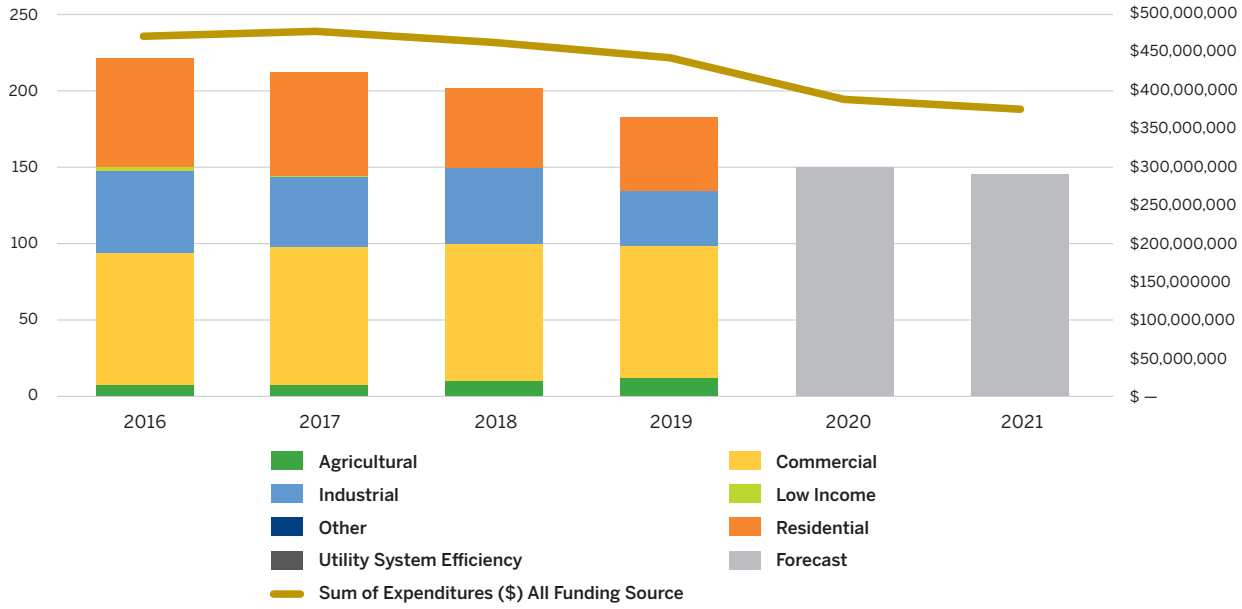
	Year	Cumulative Target (aMW)	Actual Achievements (aMW)	Actual Over/Under Target (aMW)	% Over/Under Target
5th Plan	2005	130	141	11	8%
	2006	265	293	28	11%
	2007	405	500	95	23%
	2008	550	735	185	34%
	2009	700	966	266	38%
	2010	900	1,223	323	36%
6th Plan	2011	1,120	1,503	383	34%
	2012	1,360	1,747	387	28%
	2013	1,620	2,009	389	24%
	2014	1,900	2,249	349	18%
	2015	2,190	2,492	302	14%
	2016	2,375	2,695	320	13%
7th Plan	2017	2,560	2,904	344	13%
	2018	2,790	3,133	343	12%
	2019	3,020	3,249	329	11%

[98] https://rtf.nwcouncil.org/about-rtf/conservation-achievements/2019.

[99] https://nwcouncil.app.box.com/v/2019RCPResults

[100] NPCC 2019 Regional Conservation Progress Report by the Regional Technical Forum.

FIGURE 13. Annual Program Savings (aMW) Compared to Annual Program Expenditures



Many utilities in the Northwest are national leaders in implementing energy efficiency programs. We applaud their efforts. Some utilities have not embraced this proven, low-cost resource. Failure to achieve these targets means more resources and transmission and distribution lines need to be built. These actions will add costs and present risks to upland resources like First Foods that the tribes are striving to protect. Failure to meet efficiency targets also puts more pressure on the hydroelectric system that has imposed economic resource transfers that have discriminated against the tribes' treaty secured commitments to their fishery resources.

The Council, BPA and PUCs should monitor future implementation to ensure that all utilities are meeting the targets. If the Council finds that some utilities are continuing to impose costs on other consumers, salmon, and other tribal resources, then the Council should impose a surcharge under the provisions of the Northwest Power Act.[101]

CRITFC would support a safe harbor provision to the surcharge requirements. For example, a utility could avoid the surcharge if it had: 1) well designed programs in place in all sectors; 2) offered funding to cover the cost to the consumer of the energy-efficiency improvements up to the costs of the next most expensive resource;[102] 3) had an effective public education program so all customers were aware of the programs; and 4) had committed sufficient funds to implement all requests for the energy efficiency programs.

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[101] Section 4(f)(2) of the Northwest Power Act authorizes the Council to recommend a surcharge of 10 to 50 percent for utilities that do not achieve the model conservation standards in Section 4(f)(1).

[102] The Northwest Power Act requires that the Council design the MCS to produce all power savings that are cost-effective for the region and economically feasible for consumers, taking into account financial assistance from the Bonneville Power Administration and the region's utilities.

FIGURE 14. Residential Sector Energy Savings By End Use

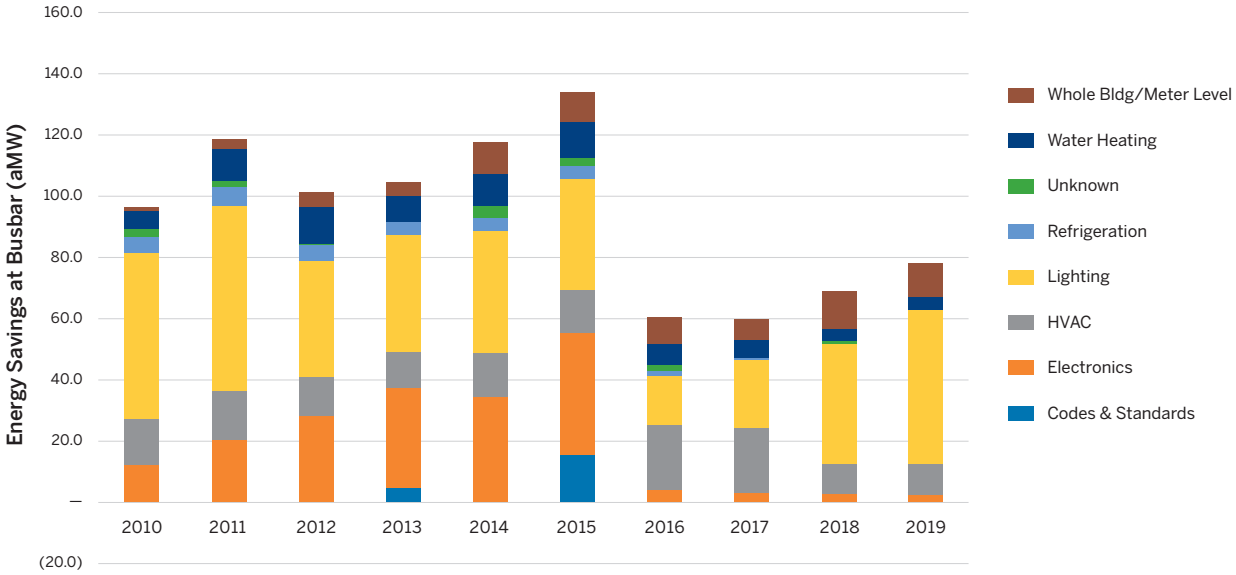
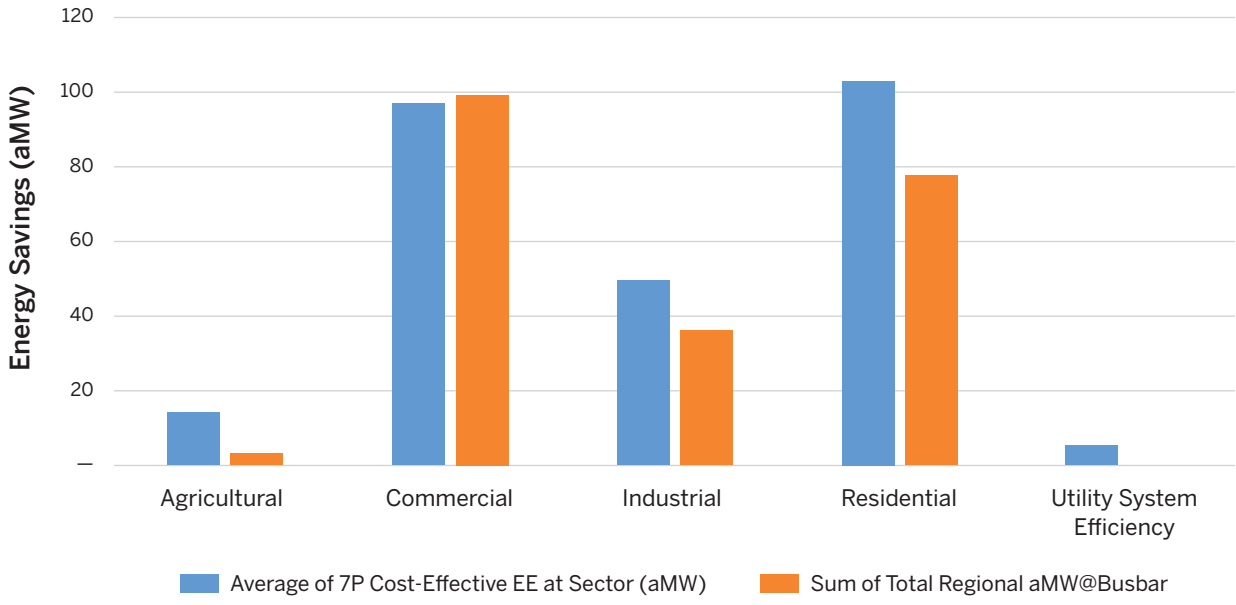


FIGURE 15. 7th Plan Cost-Effective Energy Efficiency vs. Utility System Achievements, By Sector



3.4.3. Expand Low-Income Weatherization Programs

RECOMMENDATION 19

All tribal homes and businesses should be fully weatherized by 2025 and all tribal homes and businesses should receive solar panels and battery systems that provide zero net energy by 2030.

Given the long history of damage by the electric power system to the Northwest tribes' resources, CRITFC recommends that energy efficiency and renewable resource programs implemented by private, public and federal power suppliers give priority to tribal communities. The interim target should be to weatherize all tribal homes and businesses by 2025. Furthermore, all willing tribal homes and businesses should receive solar panels with battery systems and energy efficiency improvements so that these energy efficiency and solar system resources will meet all the energy needs of the building.[103]

Tribal communities include many low-income people. Tribal poverty rates for Columbia River Treaty Tribes are still two to three times the national average. Per capita income is less than half the national average.[104] Data for CRITFC tribes are shown in **FIGURE 16** and **FIGURE 17**.[105]

The Clean Energy Transformation Act (CETA) in Washington requires utilities to ensure an equitable distribution of benefits from the transition to clean energy for all customers.[106] The act also requires utilities to make programs and funding available for energy assistance to low-income customers.

Oregon requires that the total generating capacity of community solar projects be made available for use by low-income residential customers.

RECOMMENDATION 20

Utilities should weatherize and achieve net zero energy for all low-income homes by 2035.

After forty years, too many low-income houses and multi-family buildings still have not been weatherized. People who can least afford it are exposed to higher bills. It is time to solve this problem. Achieving zero net energy will insulate people from higher future costs.

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[103] Many informal promises were made by federal officials during the 1930s that electricity would be made available to tribal people free of charge after the dams were built.

[104] The 1990–95 data (blue) were obtained from the 1999 Meyer Report, which presented information from the 1990 Special Tribal Run U.S. Census. The 2012-2016 data (orange) were obtained from the Center for Indian Country Development, which is a project of the Federal Reserve Bank of Minneapolis.

[105] YN is the Yakama Nation, CTUIR is the Confederated Tribes of the Umatilla Indian Reservation, NPT is the Nez Perce Tribe, CTWSRO is the Confederated Tribes of the Warm Springs Reservation of Oregon.

[106] Chapter 288, Laws of 2019.

FIGURE 16. Poverty Rate for Columbia River Treaty Tribes

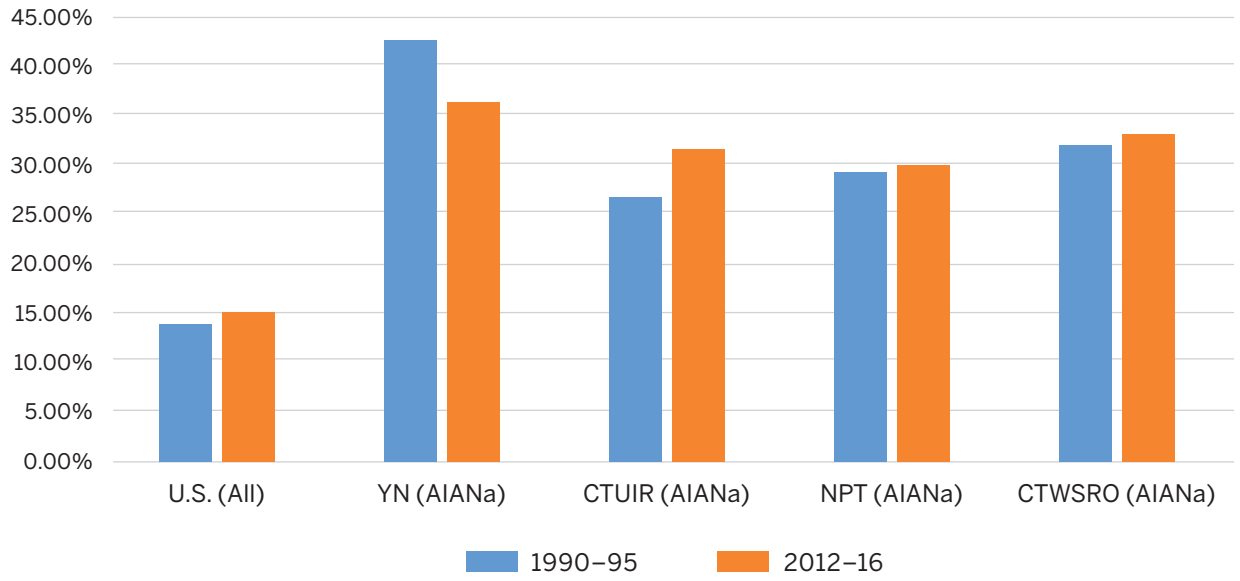
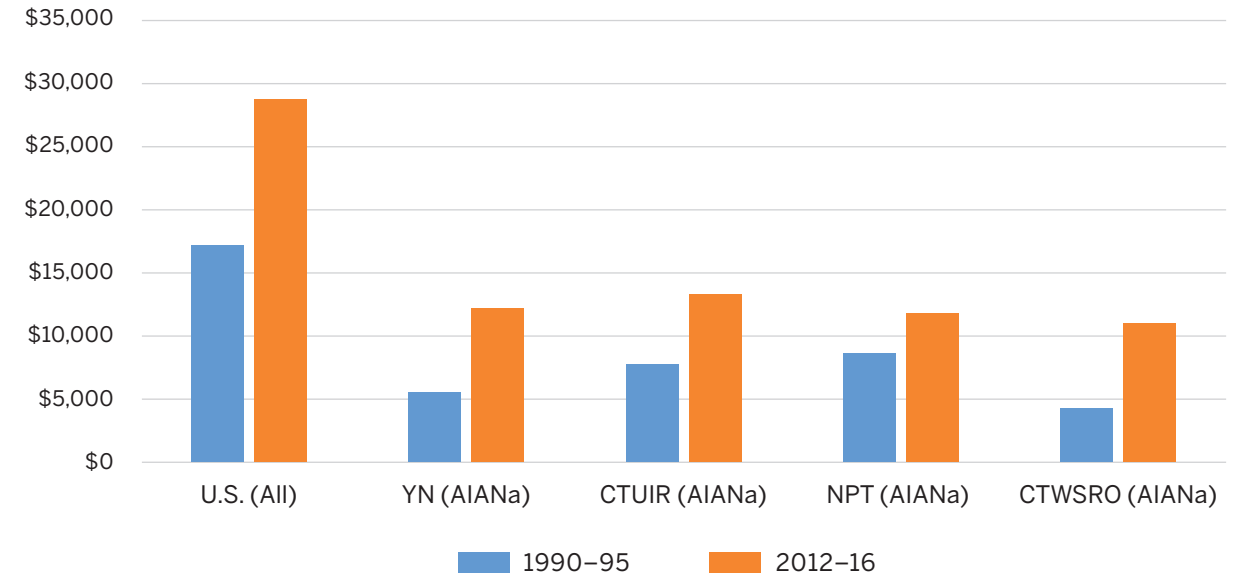


FIGURE 17. Per Capita Income for Columbia River Treaty Tribes



3.4.4. Energy Management Practices in Commercial Buildings and Industrial Facilities

RECOMMENDATION 21

Utilities, the Northwest Energy Efficiency Alliance, and other organizations should implement comprehensive programs to improve energy management practices in the commercial and industrial sectors.

Energy efficient commercial buildings and industrial facilities are a source of great potential savings, with the biggest gains in heating, ventilation, and air-conditioning (HVAC) and improved energy management in industrial plants.

Because HVAC systems and smart thermostats are complicated, they need continuing attention to remain efficient and tuned to the tasks for which they are designed. All new buildings should go through a building certification process to assure that they are operating as they were designed and to assure that the operation is efficient.

Most commercial buildings rely on programmable thermostats that are not always maintained. Many buildings are operated as though occupied continuously. Better scheduling can result in 30–40% savings in many of these buildings. With Smart Grid technologies and strategies that enable one to essentially dispatch loads behind customers' meters, these savings can now be more easily captured. We recommend a concerted regional effort to do so. In Washington state, there is a new building performance standard law that affects most commercial buildings over 50,000 square feet. It will require continuous assessment of operations and that buildings hit certain energy use targets.[107]

3.5 Renewable Resources

3.5.1. Review and Integrate Policies to Reduce Greenhouse Gases

RECOMMENDATION 22

Congress, state legislatures, the Council, and public utility commissions should review programs to reduce greenhouse gases to avoid unintended consequences.

Solar and wind development can significantly reduce greenhouse gas emissions. Lower costs, higher efficiencies, and current federal and state policies are driving an increase in these resources. The capital cost of renewable resources developed to meet state Resource Portfolio Standards (RPS) and/or clean energy standards is being recovered in rates, so when these

[107] https://www.commerce.wa.gov/growing-the-economy/energy/buildings/

resources produce power in excess of "native load need" they can be sold at very low, zero, and even negative costs.[108] As a result of the federal Production Tax Credit and Renewable Energy Credits, resource producers will pay others to take their electricity so they can get the credits.

As a result, the forecasts of future wholesale ***energy*** prices for many hours of the day and for nearly all months of the year across the WECC will continue to be low. These low prices depress the value of energy efficiency's ***energy*** (kwh) savings which in turn increases the cost of energy efficiency as a source of ***capacity*** savings.[109] Therefore, while these tax policies, cost-recovery practices and RPS requirements are intended to promote the development of non-greenhouse gas emitting generating technologies, they have the unintended effect of reducing the amount of energy efficiency that appears to be cost effective. Policy makers must recognize and account for this unintended consequence and its environmental consequences.

Even though some energy efficiency measures can reduce greenhouse gas emissions at a lower cost per ton than the cost of doing so with renewable resources, the existing incentives (tax credits, RECs) and electricity market structures make the energy efficiency measures appear more expensive. These policies may also not adequately address the high economic and environmental effects of transmission and distribution lines. Policies should address all these issues in the development of an integrated set of least-cost options for reducing greenhouse gas emissions, whether that be energy efficiency or renewables resources or most likely a combination of these resources. Unfortunately, under the current policy environment the least-cost mix of resources to reduce greenhouse gases is not likely to be developed.

These policies and standards can also have unintended and negative impacts on tribal communities and all consumers. Energy efficiency reduces consumer costs, provides energy and peak savings that are matched closely to energy needs, and provides local employment. Energy efficiency has other benefits that should be addressed in these policies, such as certainty, reliability, and insurance against heat dome and other extreme weather that can reduce some renewable resource production. Energy efficiency, along with other distributed energy resources such as batteries and demand response, can reduce the scale of renewable development needed to replace fossil fuel generation. Reducing the need for renewable resources helps avoid impacts to tribal resources associated with development of solar and wind farms and transmission lines to get their power to market. It also can reduce some large impacts to the operation of the dams and reservoirs that hurt fish and wildlife.

The NPCC and federal and state regulators and policy makers should recognize the economic and environmental value of energy efficiency and distributed energy resources in offsetting the amount of renewable resources needed so the lowest-cost carbon reduction resource development path is selected. Simply increasing RPS requirements may not produce the best outcome because it does not consider whether there are lower cost carbon reduction resource strategies and strategies that better protect tribal resources.

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[108] A producer would pay an entity to take the power so the producer can get the production tax credit.

[109] In the NPCC 7th Plan energy efficiency was selected as a lower cost source of capacity than demand response because a portion of the cost of energy efficiency was offset by its energy savings value.

RECOMMENDATION 23

The Council should analyze the integration of renewable resources under a range of scenarios for river operations.

As discussed above, CRITFC is concerned about the assumption that the intermittent renewable resources coming online will be integrated with the hydropower system using current fish requirements and the otherwise unconstrained flexibility of the hydroelectric dams and reservoirs. For example, the analyses undertaken by the NPCC assumed static fish constraints for the 20-year planning horizon of the Power Plan. At no time in the history of the Northwest Power Act have fish constraints remained static for a 20-year period. It is highly likely that fish constraints will be modified within this upcoming 20-year period.

The Council has for 40 years been a skilled practitioner of a risk-management approach to power planning. Kai Lee's paper *The Path Along the Ridge* outlined a simple rationale for rejecting simple projections of load growth and other key parameters in power planning: "There are no facts about the future but it is widely believed to be uncertain and risky." In its first power plan, the Council determined that, instead of making simple, deterministic assumptions about an uncertain future, the plan should identify a variety of scenarios and strategies that can work across the full spectrum of possibilities.

The assumption that river operations will be static over the coming 20 years is akin to assuming straight-line energy demand into the future: it's a convenient assumption but almost certainly mistaken. It simply ignores the prospect that climate change, and its implications for ocean conditions, water temperature, amount and timing of runoff and other factors, are likely to have on salmon populations.

Moreover, NPCC's draft 8th Power Plan describes unprecedented effects—conditions that simply have never been considered in prior fish and wildlife program amendment processes, ESA proceedings, or litigation. As the draft plan describes it, as renewable energy development increases dramatically, swings in river flows and reservoir levels are likely to be stark—much more dramatic than has been the case under current river operations. In light of this, existing fish protections will obviously need to be reconsidered. The starts and stops in river flows that the draft plan assumes are likely to have a much harsher effect on migrating fish than has been the case historically.

The assumption that river operations and fish protections are static is belied by the agreed-to 2022 spill and reservoir operations and the system operational requests in the Term Sheet for Stay of Preliminary Injunction Motion and Summary Judgement Schedule.[110] These interim protections in place through July 31, 2022, increase spill for juvenile fish passage, limit "zero flow" operations, and maintain reservoirs at minimum operating pools to benefit salmon migration. It is likely that additional fish protections will be necessary to respond to the challenges the fish face, and the Council should immediately consider a range of fish protections, from additional spill to restoration of the lower Snake River by breaching the four Lower Snake River dams.

[110] *NWF et al. v. NMFS* et al. (Case number 3:01-cv-00640-SI)

The Council's current approach ignores the application of the Clean Water Act to the Columbia River System and the ongoing work by the Environmental Protection Agency on water temperature and water quality. In comments on the draft Energy Vision, EPA wrote:

> *The US Environmental Protection Agency (EPA) appreciates the ability of the Columbia River Federal Power System to provide carbon free power for the Pacific Northwest. However, we are concerned about future regional river flow strategies to produce power and the impact of increasing water temperatures. On August 13, 2021, EPA reissued the Columbia and Lower Snake River Temperature TMDL. This TMDL was developed to provide information about the primary sources of temperature impairments in the Columbia River basin. The TMDL examines sources of temperature impairments on the Columbia River, from the Canadian border to the Pacific Ocean, and on the lower Snake River in Washington, from its confluence with the Clearwater River at the Idaho border to its confluence with the Columbia River.*
>
> *One of EPA's key findings is the impact of climate change on water temperature in the Columbia River. EPA determined that the warming trend due to climate change has significantly affected temperatures in the rivers since the 1960s, and these adverse thermal impacts continue to increase. A synthesis of available scientific evidence indicates that climate change has increased summer water temperatures in the Columbia and Snake Rivers by approximately 1.5°C since the 1960s. EPA's analysis also found that dam impoundments significantly contribute to warming of the Columbia and Snake Rivers in the summer and fall due to increased river surface area and increased time for water to travel through the reservoirs. These attributes of dam impoundments also magnify the rate of warming from climate change in the Columbia and Snake Rivers (see TMDL Appendix D). Actions to increase flow and provide quicker water travel time in a reservoir can decrease summer water temperature and cool the river. As the TMDL moves into the implementation phase, these types of dam and reservoir operations changes should be assessed to cool river temperatures during critical periods and locations to improve conditions for fisheries.*[111]

Putting in place an energy development strategy that assumes, and implicitly accepts, that energy development can ignore these effects will simply set the strategy up for failure. As fish stocks absorb the impacts of these unprecedented fluctuations, hydropower operations are likely to be thrown back into the ESA and litigation forums that the region has been trying to manage its way out of for 30 years.

The way to account for these effects in developing a sensible energy strategy is to analyze a range of river operations scenarios that respond to the challenges that fish are likely to face, and review energy options that make sense across the range. The Council, the progenitor of risk-based planning, is in the perfect position to bring these techniques to bear in this new era of unprecedented uncertainty.

CRITFC recommends that the Council consider a range of fish constraints in its analysis of the

[111] Comments by Mary Lou Soscia, Columbia River Coordinator, US Environmental Protection Agency, September 28, 2021.

region's energy future and make a fully informed decision in adopting Power Plan requirements. SECTION 3.1 and APPENDIX C describe near-term and longer-term changes in the configuration and operation of the hydroelectric dams that should be evaluated.

3.5.2. Wind Generation

RECOMMENDATION 24

Utilities and BPA should continue to pursue wind, and the associated efforts to integrate wind power, consistent with the tribal concerns and protections for fish, wildlife, and cultural resources.

The Northwest has been a leader in the adoption of wind power. Wind power is a low-cost source of power today, and it offers insurance against escalating prices in the future, because the "cost of fuel" is free. However, the intermittent production of wind power, and the difficulty in predicting when the wind will blow presents a problem with integrating wind into the system. Integration of wind is exacerbated under high-water, high-wind, and low-load scenarios. BPA has led a regional effort to better integrate wind into the system. We believe that wind integration will be improved by use of various storage mechanisms discussed previously in this Energy Vision report.

Siting wind projects can be controversial. The Washington Energy Facility Site Evaluation Council held eight days of adjudicative hearings and took public testimony on two separate days when considering the application for the Whistling Ridge Energy Development near Underwood Washington and adjacent to the Columbia River Gorge National Scenic Area. Ultimately the project was abandoned by the developer. Similar concerns are now facing a wind development proposed for the Horse Heaven Hills near Washington's Tri-Cities.[112] SECTION 3.6 recommends a planning process for siting renewable energy development in the Northwest.

3.5.3. Solar Generation

RECOMMENDATION 25

The region should expand its efforts to promote utility-scale solar energy.

Solar power comes with the same integration problems that affect wind, and it comes with the same benefits of cost certainty throughout the life of the system. The capital costs of solar power have decreased significantly and there are growing opportunities to develop solar and battery systems to assist in meeting energy needs.

And, as discussed below we recommend a process for siting industrial scale solar developments that may impact undisturbed lands that are valued by wildlife such as pygmy rabbits and sage grouse, both of which have been considered for listing under the Endangered Species Act. Pygmy rabbits are now listed under the ESA and a long history of sage grouse litigation continues concerning protective measures.[113]

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[112] "The thought of turning our beloved Horse Heaven Hills into a pin cushion for massive wind turbines breaks the hearts of most Tri-Citians." From the editorial board of the Tri-City Herald, https://www.tri-cityherald.com/opinion/editorials/article250063544.html

[113] https://biologicaldiversity.org/w/news/press-releases/lawsuit-aims-compel-fish-and-wildlife-service-protect-bi-state-sage-grouse-2020-09-29/; https://biologicaldiversity.org/w/news/press-releases/court-halts-drilling-on-630-square-miles-of-federal-oil-leases-in-key-sage-grouse-habitat-2021-06-10/

RECOMMENDATION 26

BPA and utilities should fund proof of concept projects for dual use solar.

The siting process discussed above and in SECTION 3.6 should also address solar development that is compatible with high-value farmland. The American Farmland Trust (AFT) provided thoughtful comments about focusing solar development on marginal lands—those that are least productive for agriculture *and* not critical for wildlife habitat. Agricultural lands that require groundwater depletions for their productivity are inherently marginal. The Council staff presented examples of innovative low-impact solar development, dual purpose projects that co-locate and integrate renewable energy with a complementary activity that gain from working together, and floating solar systems on agricultural reservoirs.[114]

AFT has proposed pilot projects to demonstrate dual use solar on agricultural land. AFT defines "dual use" as solar development that is designed with agriculture in mind. Early research has shown that well-designed dual use projects have the potential to enhance agricultural practices, such as extending the growing season, preventing evaporation, and providing shade for livestock. It can also provide passive revenue for farmers to support the commercial viability of their farming operation.

Research is underway to develop the best practices and design of dual use solar. To date, these projects have been too small for electric utility application. Funding several utility-scale pilot projects could provide a proof of concept for this approach to siting solar on agricultural land.

3.5.4. Distributed Solar Generation

RECOMMENDATION 27

States, local governments, and utilities should expand policies to promote on-site solar systems.

The costs of solar photovoltaic systems for homes and business have also decreased. These investments provide savings and certainty for the building owners. These systems have significant system benefits because they do not require expanded transmission and distribution lines and thus avoid the environmental impacts of those developments. Solar systems with batteries are designed to provide storage and backup power to improve reliability. Solar roof top and battery systems will be sited behind customers' meters. In this case, line losses and ancillary services to get the power to the load are miniscule. Also, the intermittency problem of solar power is diminished somewhat, because small photovoltaic systems will be spread over wide areas of the region. Passing clouds will affect only a small portion of the installations at any moment. Thus, predictability of solar will be enhanced.

The Council draft 8th Power Plan projects distributed solar systems will add about 1,000 megawatts of capacity and 200 average megawatts of energy by 2030. By 2045, the projection is about 5,000 megawatts of capacity and 750 average megawatts of energy. CRITFC believes these systems can provide even larger amounts of energy with appropriate incentives that recognize the full value of these systems.

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[114] Considerations of Large-Scale Renewable Resource Deployment, Gillian Charles, June 2, 2021.

Utility and government programs can further reduce on-site solar costs by supporting cooperatives that can purchase photovoltaic panels at lower-cost bulk rates and providing technical assistance to homeowners, landlords, tribal governments, and others. Programs can also provide additional financial incentives.

These policies should consider Zero Net Energy standards similar to California for new and existing houses and businesses. The evaluation of the costs and benefits of these on-site solar systems should include the savings to the transmission and distribution system discussed in SECTION 3.10 and APPENDIX E.

RECOMMENDATION 28

The Council, Northwest legislatures, energy regulators, and utilities should consider adopting zero net energy building standards.

California has implemented a mandate for zero net energy (ZNE) buildings. These are energy-efficient building with solar rooftops and batteries where the annual consumed energy is less than or equal to the on-site renewable generated energy.[115] The California goals are:

- All new residential construction will be zero net energy (ZNE) by 2020.
- 50% of new major renovations of state buildings will be ZNE by 2025.
- All new commercial construction will be ZNE by 2030.
- 50% of commercial buildings will be retrofit to ZNE by 2030.

The 2020 Oregon Biennial Energy Report[116] states:

> *Oregon Executive Order 17-20[117] targets equivalent performance to the U.S. DOE Zero Energy Ready Home specifications in the residential building code by 2023 and includes a directive for new state agency construction to be designed to be able to operate as carbon-neutral buildings after 2022. Executive Order 20-04[118] continues the trend toward increased efficiency in new construction and net zero energy buildings by targeting a 60 percent reduction in new building annual site consumption of energy by 2030, excluding electricity used for transportation or appliances, from a 2006 code baseline. This advancement in efficiency makes net zero energy achievable for some residences and building types, when coupled with installation of renewables.*
>
> *Executive Order 17-20 also includes a requirement for solar-ready provisions in the building code to make future installations of onsite renewables more accessible for building owners, which was incorporated into the Oregon residential building code[119] for new construction in October 2020. As of 2019, the Oregon commercial energy code requires completion of the "2019 Oregon Zero Energy Ready Commercial Code*

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115 See California Public Utility Commission: https://www.cpuc.ca.gov/zne/.

116 See https://www.oregon.gov/energy/data-and-reports/pages/biennial-energy-report.aspx.

117 Office of the Governor, State of Oregon. (November 6, 2017). Executive Order 17-20. https://www.oregon.gov/gov/documents/executive_orders/eo_17-20.pdf.

118 Office of the Governor, State of Oregon. (March 10, 2020). Executive Order 20-04. https://www.oregon.gov/gov/Documents/executive_orders/eo_20-04.pdf.

119 Oregon Building Codes Division (October 1, 2020). 2017 ORSC Amendments Solar Readiness Requirements for New Residential Buildings. https://www.oregon.gov/bcd/laws-rules/Documents/20201001-17orsc-solar-amendments-tr.pdf.

Compliance Form" that, while not specifically requiring onsite or offsite renewables in the code, includes a requirement for an estimation of building energy consumption, renewables needed to achieve net zero energy, and the onsite renewable generation potential. This helps raise awareness of net zero energy buildings and what is needed to achieve that level of performance. Utility programs, energy policies, energy codes, voluntary performance standards, and interested building/homeowners all contribute to advancing net zero buildings.

Building and retrofitting homes and business to be very energy efficient and adding solar or wind energy with a battery system has many advantages. With the right incentives, it would reduce consumer costs, reduce peak demand and energy needs at all other times, and reduce the costs of expanding transmission and distribution power lines. These are fish and environment friendly measures. All these factors should be included in calculating the cost effectiveness of these programs.

Zero net energy homes and building also provide energy security to the region and to individuals. They provide insurance against droughts that limit electricity from the dams, wildfires that disrupt transmission lines, cold snaps and heat waves that drive up electricity demand, and other natural disasters that will become more common as the climate warms. These benefits should be recognized in reliability forecasts.

A major effort to build and retrofit low-income residences that was recommended above will likely reduce the costs of achieving this goal in all structures. For example, the Council called on BPA and utilities to pay the incremental costs of meeting efficient building codes in the 1980s. As a result, the costs of materials and installation were reduced significantly, and these payments were no longer needed.

RECOMMENDATION 29

State and local governments should adjust building codes to ensure that they can accommodate on-site batteries.

In some areas, building or fire codes could limit the size of an on-site battery. These codes should be revised.

3.5.5. Other Renewable Resources

RECOMMENDATION 30

The Council, BPA, and utilities should continue to monitor and support other promising renewable resources.

We focused on wind and solar above, but other renewable resources either at specific sites or with technological breakthroughs may be cost effective and have fewer environmental impacts. Offshore wind, geothermal energy, and biomass have been used successfully where the right conditions exist. And wave power, although in its infancy, may be cost effective in the not-too-distant future. The growing focus on the climate crisis and environmental protection may produce new innovations with lower impacts. Funding for research and pilot projects can help stimulate new technologies. Where these resources show promise, the promise should be explored, and implementation should be pursued when and where analyses show them to be ready for commercial production and can be integrated within the power grid.

3.6 Develop a Comprehensive Plan for Strategically Siting Renewable Resources and Transmission

RECOMMENDATION 31

CRITFC and its member tribes should work with state energy and siting agencies, federal agencies, Northwest Grid, the Northwest Power Pool, and others to develop a timely comprehensive plan for siting renewable resources and transmission lines that builds in efforts currently being developed in the states.

The recommendations for energy efficiency, demand response, clear price signals, and distributed generation can reduce the need for new resources and additional transmission lines. We recognize that meeting the goals to reduce greenhouse gases will likely require additional development of significant additional renewable resources and some transmission lines. Therefore, CRITFC recommends the region prepare a timely thoughtful plan for where renewable resources should be developed, and where they should not. The plan should provide expeditious siting with clear and uniform standards across all political subdivisions that sites resources near loads and within the grid to relieve congestion, and that protects fish, wildlife, and other environmental values and tribal resources.[120]

Strategically siting some electricity generation closer to loads, in combination with reducing peak energy demands, will eliminate some of the planned costs and impacts associated with expanding the transmission and distribution system. Utilities must develop interconnection standards[121] that allow for safe operation of local generators. Distributed generation can be deployed to eliminate the need for backup generation and transmission and distribution capacity.

Distributed generation resources include fuel cells, net-metered small renewable resources, and small wind farms. Owners of net-metered small renewable resources, including solar photovoltaic applications, can sell power back to the local utility at retail prices. Small wind farms of two to ten machines can be placed

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[120] CRITFC's member tribes have ample experience with the devastating impacts of carbon free resources, such as the Columbia River Basin's system of dams that deeply impacted the tribes. These impacts have been documented in extensive surveys. https://www.critfc.org/wp-content/uploads/2014/11/circum.pdf. Even contemporary projects like the $2 billion pumped storage project proposed near Goldendale WA pose impacts to tribal cultures and economies and can be expected to face stiff tribal opposition. Situated directly on a sacred tribal site, the proposed project directly impacts Yakama Nation cultural, archeological, ceremonial, monumental, burial petroglyph and ancestral use sites.

[121] FERC has a NOPR to make interconnection standards simple and uniform throughout the country. See Standardization of Small Generator Interconnection Agreements and Procedures Advance Notice of Proposed Rulemaking, Docket No. RM02-12-000, issued August 16, 2002.

strategically within the grid and not necessarily where wind is the greatest, but where the combination of strategic placement and the wind resource yields the highest benefit to the electricity system. This benefit would show up as income to the wind developers and savings in transmission and distribution construction costs.

Moving new renewables next to existing transmission is another siting strategy that could minimize the costs and impacts of adding new resources. For example, Montana wind is well positioned to serve westside load centers while minimizing impacts on river operations. In addition to having the highest capacity factors (40–50 percent), it generates primarily during the winter, so its generation pattern best fits PNW peak load shapes; and it can use over 1 GW of repurposed Coalstrip transmission rather than needing to build new, much more expensive transmission to serve westside loads. Because of these characteristics, Montana should help meet PNW winter capacity needs while also lessening river operation and upland impacts.

Strategic siting of new resources is just one piece of a comprehensive siting plan; siting of new resources will also need to consider—and avoid—adverse impacts to fish and wildlife and other environmental values and tribal resources. According to the Washington Department of Fish and Wildlife, 30 industrial solar projects are proposed for Washington with a footprint of 49,000 acres, or nearly 77 square miles. All but one of those projects would be in the Columbia Basin. The Oregon Department of Energy (ODOE) reports that the state Energy Facility Siting Council has approved seven projects and has seven more under review. The 14 projects cover 27,969 acres or 44 square miles. Local siting processes in Oregon would likely add to this total.

Facilities sited on shrub steppe compromise the function of sagebrush and grassland ecosystems and degrade habitat for deer, elk, greater sage grouse, ferruginous hawk, pygmy rabbit, and many other species. Developments also risk excluding tribal members from their traditional cultural foods and medicines, either through loss of the foods, loss of access to the foods, or both.

In the mid-1980s, over 70 small hydroelectric facilities were proposed by private developers to the Federal Energy Regulatory Commission for licensing and development in the Salmon River Basin of Idaho. The National Wildlife Federation and the Nez Perce Tribe objected to initial steps in this development proceeding without a comprehensive plan of review. *National Wildlife Federation v. Federal Energy Regulatory Commission, 801 F.2d 150, 1507 (9th Cir. 1986).* The Ninth Circuit Court of Appeals emphasized Congress' commitment in the Federal Power Act to coordinated study and comprehensive planning along an entire river system before hydroelectric projects are authorized. This particular conflict and other similar conflicts over siting small hydro development in the Columbia Basin led to the regional policy adopted by the Northwest Power and Conservation Council and Bonneville Power Administration establishing "protected areas" where hydro project development is discouraged.[122] The current incentives for wind and solar developments are creating

[122] For more information and for the formal Protected Areas provisions, see the 2014 Fish and Wildlife Program's Protected Area Strategy (Part Three, Section IV (A)(5)) and Appendix F to the Council's 2014 Columbia River Basin Fish and Wildlife Program, available at https://www.nwcouncil.org/sites/default/files/2014-12_1.pdf. A 2020 Addendum was added to the 2014 Fish and Wildlife Program, but the text of the 2014 Program—including the Protected Area strategy—remains in effect. See https://www.nwcouncil.org/sites/default/files/2020-9.pdf.

an analogous situation, where impacts of uncoordinated renewable resource development may permanently harm the Basin's water, fish, wildlife and cultural resources.

A siting plan like the one used in the 1980s for regional small hydro development, should be developed to guide renewable resource siting. The plan should take a programmatic approach considering reasonably foreseeable impacts associated with such development. All affected tribes should be included during the early phases of siting, planning, and permitting processes by both state and federal governments. The plan could assess renewable resource sites and prioritize their potential for development. Potential aesthetic, wildlife, and cultural resource impacts, all of which may bear upon site selection, and related issues, such as the location proximate to load or need for new transmission, could be examined. The following examples demonstrate how such siting plans have been developed and what a plan could address.

- In October 2012, the Department of the Interior completed such a plan for development of solar energy on public lands in six western states. The Programmatic Environmental Impact Statement (PEIS) for solar energy development provides a blueprint for utility-scale solar energy permitting in Arizona, California, Colorado, Nevada, New Mexico and Utah by establishing solar energy zones with access to existing or planned transmission, incentives for development within those zones, and a process through which to consider additional zones and solar projects.
- The Solar PEIS establishes an initial set of 17 Solar Energy Zones (SEZs), totaling about 285,000 acres of public lands, that will serve as priority areas for commercial-scale solar development, with the potential for additional zones through ongoing and future regional planning processes. If fully built out, projects in the designated areas could produce as much as 23,700 megawatts of solar energy, enough to power approximately 7 million American homes. The program also includes a framework for regional mitigation plans, and to protect key natural and cultural resources the program excludes approximately 79 million acres that would be inappropriate for solar development based on currently available information.
- In January of 2013, the Department of the Interior completed a plan for renewable resource development in Arizona. The Restoration Design Energy Project (RDEP) is an initiative to identify lands that may be suitable for the development of renewable energy. The RDEP Record of Decision and Approved Resource Management Plan Amendments establish 192,100 acres of renewable energy development areas on BLM land throughout Arizona. These areas are near transmission lines or designated corridors, close to population centers or industrial areas, and in areas where impacts on water usage would be moderate. These lands also have few known resource impacts or have been previously disturbed. One example is retired agriculture property. These areas are available for solar or wind energy development. In addition, the Plan establishes the Agua Caliente Solar Energy Zone on 2,550 acres in western Arizona.
- In 1986, the Northwest Power and Conservation Council adopted Protected Areas into the Columbia River Fish and Wildlife Program. These provisions protected 44,000 stream miles of habitat that was important for fish and wildlife. The provisions were recognized by the Federal Energy Regulatory Commission pursuant to its mandates under

the Northwest Power Act. Protected Areas had the effect of avoiding disputes and wasted resources on sites that had significant fish and wildlife impacts and focusing development where it was unlikely to have negative impacts.

- The Oregon Department of Energy (ODOE) is developing the Oregon Renewable Energy Siting Assessment (ORESA) online mapping and reporting tool to inform this type of work. An initial version expected in Winter 2021 and project completion is expected in Spring 2022. ODOE may build on the ORESA project through the 2022 Biennial Energy Report regarding resource planning considerations with land use impacts of renewables. ODOE is involving a diverse group of stakeholder hopes that an online mapping and reporting tool will support efforts to carve out priority locations.
- Washington State has several efforts to address the siting of renewable energy and related infrastructure. The Compatible Energy Siting Assessment (CESA) is a joint effort of the Washington State Department of Commerce and Washington State Energy Facility Site Evaluation Council which supports Washington clean energy goals by identifying renewable energy siting and development.[123] The CESA effort includes a prototype mapping tool.[124]The Washington Transmission Work Group was mandated by the Clean Energy Transformation Act (CETA) of 2019 to review the need for upgraded and new electricity transmission and distribution facilities and is expected to report its findings in a final report due by Dec. 31, 2022. Washington State University will begin an effort to launch a least-conflict solar siting plan in the Columbia Basin and central Washington.

The need for such comprehensive planning was highlighted in a separate concurring opinion in the Whistling Ridge wind development proceeding before the Washington Energy Facility Site Evaluation Council in 2011. *Whistling Ridge Energy Project, Washington EFSEC Order No. 868 (October 6, 2011)*. "Absent such a plan… economic considerations will be paramount and the broader public interest in protecting the environment could finish second. This is in no one's interest, least of all renewable resource developers" (James Luce, Chair).

The region would benefit from a comprehensive planning process that would guide renewable resource development and siting for wind, geothermal and solar technologies, and for transmission lines to favorable locations and outcomes for regional fish, tribal cultural resources, and energy needs. Common to each of the foregoing plans was the concept of developing criteria that would protect key resources by designating areas where development should be avoided as well as criteria that could guide development to areas where development could be incentivized.

Such criteria could stimulate innovations in renewable resource siting. For example, "low-impact" solar is designed to improve soil health, retain, water, nurture native species, and produce food. These projects preserve natural habitat, rather than leveling land and removing topsoil to use gravel or artificial grass.[125] The NPCC has also reported on dual purpose projects that integrate renewable projects such

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[123] See https://www.commerce.wa.gov/serving-communities/growth-management/growth-management-topics/military-base-land-use/

[124] See https://storymaps.arcgis.com/stories/b2984ef464db408c86a744d31ccbd0e0

[125] InSPIRE project stands for Innovative Site Preparation and Impact Reductions on the Environment. From NPCC June 2021 presentation.

as livestock grazing, beehives, and certain crops. A National Renewable Energy Laboratory study identified over 25,000 man-made reservoirs that could be covered with floating solar systems to reduce evaporation and algae growth and supply ten percent of U.S. power.[126] The criteria might also promote repowering existing sites to improve efficiency and output.

In the Columbia Basin context, the following criteria are offered as examples of criteria that could protect tribal interests on their ceded lands that comprise much of the interior Columbia Basin.

Summary of Siting Recommendations:

Areas to avoid in siting renewable energy resources and transmission development:

- Sites that would involve direct disturbance of tribal First Foods, including:
  - Water
  - Salmon and culturally significant fish species bearing watersheds (*e.g.,* Pacific Lamprey, suckers, white mountain trout, etc.)
  - Ungulate (big game) calving, and critical feeding grounds and travel corridors
  - Cultural food plants and medicines
  - Berry fields
- Sites with high potential for direct disturbance of tribal archaeological and cultural resources as defined by the tribes
- Sacred sites
- Areas of tribal cultural use (*e.g.*, cultural food gathering)
- Sites where birds of prey will be impacted
- Critical habitat areas (designated and proposed) for species under the Endangered Species Act of 1973 or under state sensitive species statutes.

Areas to incentivize for renewable resources development:

- Sites that already have transmission. For example, expanding wind production in Montana could use existing transmission lines that were used to transmit electricity from coal plants that are phasing out.
- Sites already disturbed by tilled agriculture (see the discussion of dual use solar project above).
- Sites where ecological and energy benefits are complementary, such as reducing irrigation demand by siting solar and wind development where ground water resources are depleted, and making complimentary arrangements to protect long-term agricultural interests
- Sites that do not require extensive new transmission resources
- Currently designated industrial zones
- Land areas outside the anadromous fish zone

The BLM Final Programmatic EIS for Solar Energy Development[127] had some similar criteria for solar development in the desert Southwest,[128] which applied to both action alternatives. Several of the criteria are highlighted in **TABLE 7**.

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[126] Floating Photovoltaic Systems: Assessing the Technical Potential of Photovoltaic Systems on Man-Made Water Bodies in the Continental United States, Spencer *et al,* Environmental Science and Technology, 2019, 53(3), pages 1680–1989.

[127] Final Programmatic Environmental Impact Statement for Solar Energy Development in Six Southwestern States, BLM and DOE 2012, available at https://solareis.anl.gov/documents/fpeis/index.cfm.

[128] *Id.* at Section ES2.4.2.2.

These and other criteria were developed to address the potentially affected interests in the desert Southwest, including Arizona, Nevada, New Mexico, Colorado and portions of California. Some of the criteria are likely to be suited to the Columbia Basin. An excerpt from the FPEIS can be found in APPENDIX F. Numerous maps were developed by the U.S. Bureau of Land Management for the EIS that described areas for potential development. **FIGURE 18** is an example shown for the State of Nevada.

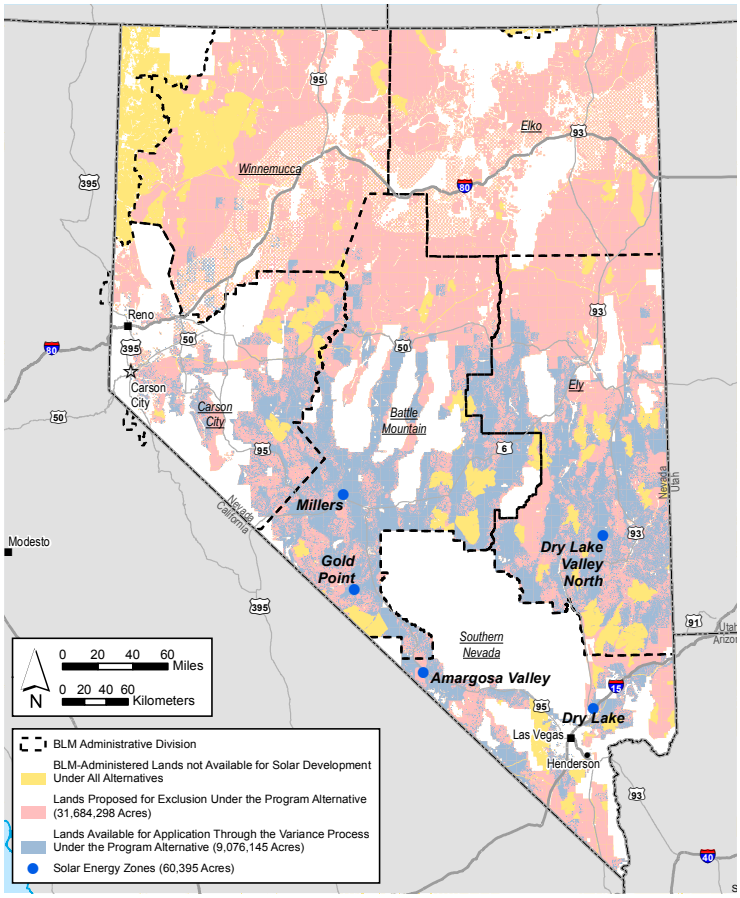
TABLE 7. Examples of Criteria Used to Determine Areas for Exclusion Under the BLM Solar Energy Development Program Alternative

1. Lands with slopes greater than 5% determined through geographical information system (GIS) analysis using digital elevation models.
2. Lands with solar insolation levels less than 6.5 kWh/m^2/day determined through National Renewable Energy Laboratory solar radiation GIS data
3. All Areas of Critical Environmental Concern (ACECs) identified in applicable land use plans (including Desert Wildlife Management Areas [DWMAs] in the California Desert District planning area).
4. All designated and proposed critical habitat areas for species protected under the Endangered Species Act of 1973 (as amended) as identified in respective recovery plans.
5. All areas for which an applicable land use plan establishes protection for lands with wilderness characteristics.

Further discussion of the analysis underpinning this map is set forth in APPENDIX F.[129]

CRITFC recommends the federal government, state siting councils and the tribes immediately undertake a collaborative process for developing such a siting plan to protect Columbia Basin fish, wildlife, and cultural resources. Access to state and federal incentives for resource development should be contingent upon compliance with the plan's siting criteria.

FIGURE 18. U.S. Bureau of Land Management Potential Solar Development in Nevada



Source: https://solareis.anl.gov/documents/fpeis/maps/alternatives/Final_Solar_PEIS_NV_map.pdf

[129] Also available at https://www.energy.gov/sites/default/files/EIS-0403-FEIS-Volume1-2012_0.pdf on pages 2–20 through 2–22.

3.7
Resource Adequacy

RECOMMENDATION 32

The Northwest Power Pool Resource Adequacy Program should address fish and wildlife protections.

The peak load reductions, energy efficiency, storage, and renewable resources recommendations above will all assist the region to provide adequate electricity supplies.

The Northwest Power Pool is updating its Resource Adequacy program. This effort is designed to address Pacific Northwest capacity shortfalls through 2030. If successful, the Northwest Power Pool Resource Adequacy Program will achieve electric system reliability while minimizing pressure on the existing hydroelectric system as the *de facto* fallback, with predictable adverse impacts on salmon, when the region is capacity short. The program description states: "the capacity program will not initially focus on longer time-horizon of fuel-related issues (*e.g.,* dry water years), though we understand those issues are important."

CRITFC has recommended that a principal feature of the Adequacy Program should focus on a planning reserve margin (PRM), or reliability buffer, to guard against unanticipated reliability events and protect the region's natural and cultural resources. While individual utility PRMs have typically centered around 15 percent, the Resource Adequacy program should increase this buffer to ensure reliability for both capacity needs and energy shortages in a low-water years. CRITFC notes that the California Independent System Operator (CAISO) requires utilities to purchase a resource adequacy product and is reportedly moving to a 20 percent reserve margin to help solve California's reliability problems.

In the near term, these reserves are likely to require having combustion turbines on standby. There may be opportunities to fuel these plants with biofuels that reduce their net carbon footprint. CRITFC recommends that the Power Pool and utilities prioritize such opportunities. Additional near-term reserves are likely to be fueled by natural gas. While CRITFC strongly supports the long-term elimination of all fossil fuels to address the climate crisis, in the near term, there may be circumstances where the choice is burning some natural gas or shutting down river operations and killing migrating salmon. This has happened in the past with devastating effects to tribal resources. Therefore, CRITFC supports rate treatment for the costs associated with maintaining, staffing, fuel contracts and fuel storage, and other costs for these resources.

These actions would likely address near-term capacity concerns and low-water energy concerns; however, there are high costs associated with maintaining generating resources that may only run a few times a year or a few weeks during a decade. Over the longer term, implementing CRITFC's recommendations on reducing peak loads, promoting energy efficiency, properly integrated renewable resources, and other dry-year strategies, provide a range of other longer-term actions to maintain resource adequacy at lower costs without damaging fish and wildlife and other tribal resources.

RECOMMENDATION 33

The California Public Utilities Commission and the California Independent System Operator should address reliability issues in California that could affect the Northwest.

Power disruptions in California can also affect the Pacific Northwest. The California Public Utilities Commission and Independent System Operator are working to address the problems that caused the blackouts in 2020. The system in California relied on *average* load forecasts rather than forecasts for critical hours of the day (for example, the peak hours between 4 pm and 10 pm that occur every day during July through September). The California forecasts also relied on *average* estimates for wind and solar output. However, hourly loads and resources vary greatly in California. As the sun sets, the energy from solar systems drops quickly, but the air conditioning electricity requirements continue—this creates a high risk of shortages around 7 pm when net demand reaches its peak. Given these known power system dynamics, the California Public Utilities Commission's reliability and planning targets were badly outdated.[130] They need to be revised. These revisions are likely to demonstrate a need for improved forecasts, more resources, including energy efficiency, better coordination with the Northwest, or a delay in retiring existing resources, to avoid future problems that could spill-over into the Columbia Basin.

3.8 Additional Actions to Address Emergencies

RECOMMENDATION 34

BPA and Congress should address repayments to the Treasury to avoid curtailment of fish and wildlife protections.

In the past, BPA has reduced fish and wildlife protections when low-water or higher costs threatened its ability to meet its annual payment to the U.S. Treasury.[131] CRITFC recommends that BPA increase its probability of repaying the Treasury on time and in full, thus reducing the chances that BPA would get into a position where it might have to choose between meeting fish obligations and deferring a payment to the Treasury. BPA's obligations to fish must come first. As an alternative, Congress could enact legislation that would provide the flexibility to refinance a payment to address extraordinary circumstances. Under no circumstances should fish protection be sacrificed to assure Treasury payments.

BPA has made some changes in its rate structure to increase revenue when financial reserves drop below certain thresholds—to begin replenishing financial reserves prior to needing to trigger the Cost Recovery Adjustment Clause. CRITFC continues to recommend that BPA expand the circumstances that could trigger the emergency provisions and increase the amount it could collect in these circumstances. Moreover, we were disappointed that BPA's stewardship obligations

[130] Randy Hardy, *Analysis of Three Agency Report on August 2020 California Power Outages*, October 15, 2020.

[131] BPA repays the costs of the federal dams and transmission system.

for fish and wildlife were not addressed on par with its power mission in its 2021 strategic plan.

BPA has reduced in real terms funding available for its fish and wildlife program. It has also made changes that reduce fish and wildlife operations. CRITFC will continue to work to address these concerns.

3.9 West Coast Energy Market

RECOMMENDATION 35

The Pacific Northwest utilities, states, and federal agencies should closely monitor West Coast energy market developments to ensure that they address impacts on Columbia Basin Fish and Wildlife and other tribal resources.

The growth of formalized markets has changed the way wholesale power is acquired. There are very few bilateral wholesale power purchase agreements as most transactions are now coordinated through market participation. Therefore, the design and incentives in these markets are important to overall power system operations.

California has an active Independent System Operator to coordinate electricity generation and distribution. Wide area market integration, through BPA participation in the Western Energy Imbalance Market (EIM) and ultimately an enhanced day-ahead market (EDFAM) can facilitate access to other sources of generation and flexibility when the hydrosystem is constrained. These constraints need to be priced into the hydro dispatch and reflected in marginal prices. BPA has decided to join the EIM; implementation is expected in March 2022. Further wide area coordination can take some pressure off the system.

It may be possible that closer coordination between regions can improve reliability and address resource adequacy problems. It will be important to work with California to ensure their operations do not adversely impact salmon migration and survival as discussed above.

3.10 Transmission and Distribution Costs and Reliability

RECOMMENDATION 36

BPA and utilities should invest in solutions that minimize transmission and distribution expansions.

As discussed above and in more detail in APPENDIX E, there are significant economic and environmental costs associated with the existing and new transmission and distribution lines.

CRITFC estimates that BPA and four Northwest investor-owned utilities spent approximately $8.8 billion on transmission between 2016 and 2020. Of this total, BPA spent $1.4 billion on transmission capital expenses. BPA is projecting another $2 billion between 2021 and 2025[132] for a ten-year total of $3.4 billion. The funding for expansion of BPA system represents more than half theses total costs. BPA spent $601 million between 2016 and 2020 and is projecting a transmission expansion program totaling $730 million over the next five years.

CRITFC was able to compile distribution and transmission costs from the past five years for four investor-owned utilities in the region that totaled $6.8 billion. The information for the investor-owned utilities did not have details on expansions.[133]

CRITFC could not find enough detail to determine how much of these costs were related to activities that could be reduced or delayed if additional energy efficiency, on-site solar, and peak-demand reduction programs described in this document had been implemented.

If utility spending on transmission and distribution over the next five years is similar to the recent past, the total BPA and investor-owned spending could total $8.8 billion. Spending by other utilities would add to this total. If additional energy efficiency, on-site solar, and peak-demand reduction programs described in this document could reduce the transmission and distribution capital costs by ten percent, it could save consumers approximately $880 million over the next five years. Even a five percent reduction in the construction of new transmission and distribution systems could save consumers about $100 million per year.

The large magnitude of these transmission and distribution costs and the significant potential for savings for consumers and the environment should convince regional energy decision makers to focus on the benefits of reducing these economic and environmental costs. The construction costs are averaged into utility rates, so consumers do not see the magnitude of the expense. The environmental costs often fall on tribal resources (such a First Foods and sacred sites), rural areas, and populations that are not represented in energy siting or ratemaking processes. Investor-owned utilities receive a rate of return on these investments. All these factors may create an incentive to expand these facilities rather than pursue activities that reduce the need for these expensive assets. Therefore, CRITFC recommends that all proposals for transmission and distribution expansions should evaluate the other alternatives described in this Energy Vision that could delay or eliminate the need for the project. BPA and utilities should pursue those alternatives when they reduce costs or cultural and environmental impacts.

BPA and utilities should also implement time-of-use transmission pricing that is based on the cost of adding new facilities. Some of BPA's customers are charged for the highest transmission use in a year; however, these marginal uses are priced at the average cost of the transmission system, not the full cost of meeting peak or the cost of expanding the system.

These efforts to reduce the costs and impacts of transmission and distribution lines will require an interstate approach that addresses the actions of federal and state agencies, utilities, utility regulators, and siting agencies.

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[132] BPA Historical & Future Capital Spend, page 8 of presentation on Integrated Program Review 2, March 2, 2021.

[133] See **APPENDIX E** for details on these costs.

RECOMMENDATION 37

BPA, utilities, and public utility commissions should develop a transparent system to report transmission and distribution costs.

CRITFC has tried to find information on past and future costs for the expansion of transmission and distribution systems. The BPA expansion cost information was readily accessible and is detailed in APPENDIX E. Past utility costs were available through Security and Exchange Commission filings, but they were convoluted and lacked detail. CRITFC could not find information on public system activities.

The Oregon PUC has directed Oregon investor-owned utilities to conduct Distribution System Planning, which is a holistic, transparent, and inclusive planning process focused on maximizing operational efficiencies and customer value on the distribution system. The localized and customer-side solutions identified through distribution system planning can help avoid unnecessary infrastructure investments, save utility customers money, and provide societal and resilience benefits to communities.[134] A system that clearly tracks past and projected future costs could be a model for other utility commissions to adopt.

RECOMMENDATION 38

BPA and utilities should address transmission reliability.

Climate change has caused a significant increase in the number of fires in the Western United States. In some cases, overloaded transmission lines have ignited fires. In other cases, fires have threatened transmission lines. These fires raise issue concerning transmission cost and reliability that involve both the east to west transmission lines across the Oregon and Washington and the California Intertie (AC and DC) along the Cascades.

FIGURE 19 superimposes 2021 wildfires over BPA's transmission system.

The fires in 2021 caused interrupted deliveries to California in July **(FIGURE 20)**.

Increased integration of the Pacific Northwest and California could address some of the issues identified in this Energy Vision. Utilities and system operators will need to address these transmission reliability issues. As discussed at page 41, the Infrastructure Investment and Jobs Act provides support for grid modernization including:

- $3 billion for Smart Grid investments.
- $10 billion in additional borrowing authority for BPA.
- $1 billion to upgrade transmission between Canada and the U.S. related to the Columbia River Treaty.
- A $2.5 billion revolving loan fund for new transmission lines or upgrades.

Fish protection measures need not be sacrificed to provide transmission stability. Rather transmission services need to be planned and developed in a way that enables salmon protection measures to be implemented at high levels of reliability.

[134] OPUC Order, available at https://apps.puc.state.or.us/orders/2020ords/20-485.pdf.

FIGURE 19. 2021 Wildfires Superimposed Over BPA's Transmission System

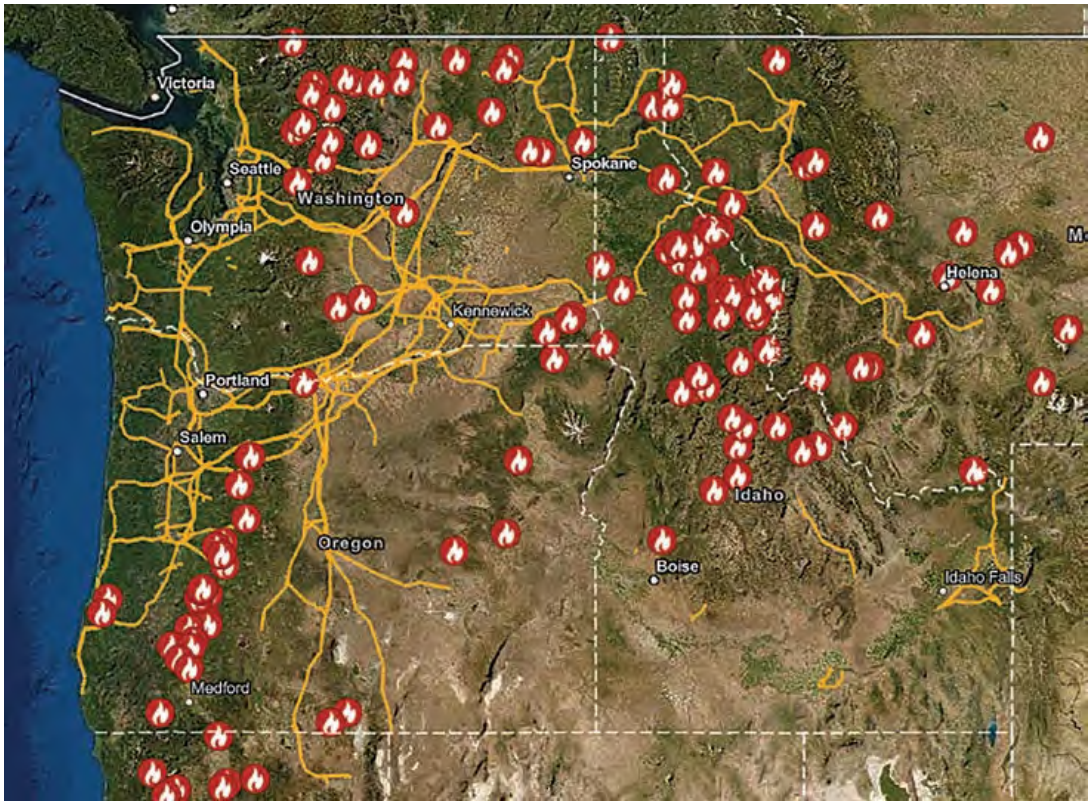
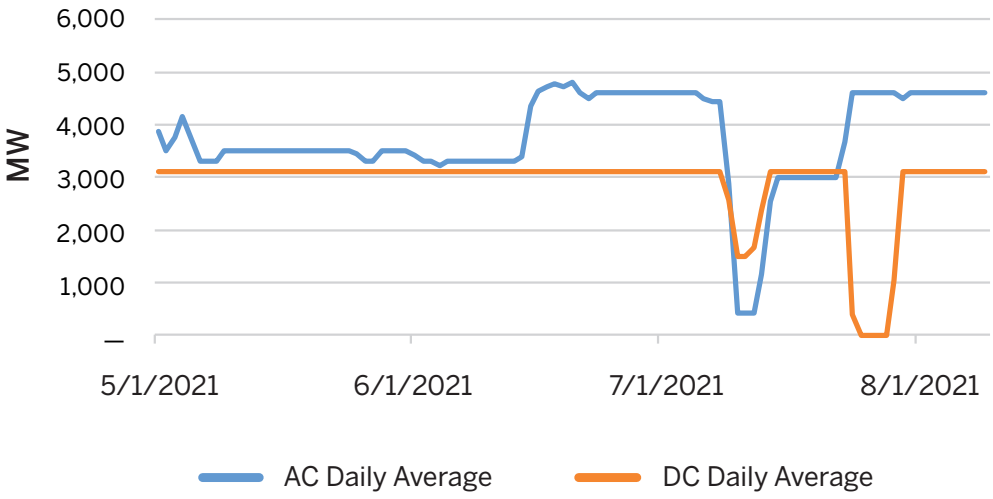
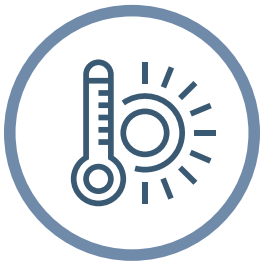


FIGURE 20. BPA AC/DC Intertie Capacity—Summer 2021



3.11
Reduce Reliance on Fossil Fuels



RECOMMENDATION 39

Federal, state, and local policy makers should develop programs to reduce the use of fossil fuels.

It is impossible to discuss energy without talking about carbon-based fossil fuels such as crude oil, coal, and natural gas. Their products and by-products include petroleum-based fuels (*e.g.,* butane, diesel, kerosene, liquefied natural gas, liquefied petroleum gas, propane, fuel oil), crude oil, natural gas, various types of coal, and methane. From extraction, to conveyance, to consumption, and by-product waste treatment, fossil fuels dominate global energy markets and drive climate change and hazardous waste management. The extraction, transport and use of fossil fuels are generally incompatible with Tribal Nations' ultimate obligations to protect sacred First Foods and precious water.

The fossil fuels life cycle includes points of extraction, conveyance and import or export project siting such as receiver terminals, refineries, and power plants, and finally consumption, usually through a combustion process. At each step to fossil fuel use, the planet and its resources are harmed. While fossil fuel extraction is not a dominating issue in the Columbia River Basin, the region is a target location for fossil fuel transport and export projects. The Basin also suffers from regional and global consumption effects, such as air deposition of mercury from coal plants in Asia.

These developments have placed undue burdens on the backs of the Region's salmon populations.

In the Columbia River Basin, fossil fuel projects include transport terminals, refineries (located on northern Puget Sound native lands), and gas and coal-fired generation plants. In the 1970s, there were proposals for pipelines from northern Puget Sound area to the Midwest. These proposals would have provided a few dozen jobs offloading supertankers and created significant risks to the environment and communities that depended on it.[135]

In 2005 there were proposals to import liquefied natural gas through ports along the Columbia River (these proposals were later reverted to developing export terminals when fracking in the United States became economical). Later coal companies eyed markets in Asia and rail lines that connected the Powder River Basin with the Pacific Northwest, and by 2012, crude oil companies were considering similar options, finding rail suitably cheaper than pipelines to export large quantities of Bakken crude and Canada oil sands (bitumen) crude. Bitumen's toxic by-product, petroleum coke, is also transported through the Columbia River Gorge.

[135] In 1977, Senator Warren Magnuson added an amendment to the Marine Mammals Protection Act to ban the construction of an oil superport inside Puget Sound that was designed to deliver crude oil to the Midwest.

Transport terminals usually include three separate components: the conveyance that serves the terminal, the terminal itself, and the marine vessels to export the product. These terminals are transitional facilities that cannot operate but for the other transport components. Typical conveyances include rail, barge, trucking, and pipeline. Of these options, rail is the component with the least amount of state, tribal, or federal regulatory oversight. In addition, many states and federal agencies are reluctant to comprehensively analyze the risks transport of fossil fuels poses to human health and the environment, leaving high consequence risks unmitigated. This poses an advantage to project proponents who, in the last decade, have rushed to propose dozens of fossil fuel-by-rail projects, particularly crude-by-rail and most recently, methane and liquefied natural gas by rail.

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Export projects do not provide abundant energy to regional markets, but rather burden local resources, increase risks of catastrophic harm, and provide no benefit for affected tribes. Starting in 2010, dozens of fossil fuel transport projects were proposed for the Pacific Northwest, specifically the states of Oregon and Washington, and the province of British Columbia. Regional tribes and First Nations were forced to spend time and resources analyzing and unifying in opposition to this onslaught. Most of the projects were not permitted, due in large part to tribes' coordination with allies in the environmental community, groups such as "Power Past Coal," "Stand Up to Oil," and "Power Past Gas." In the landscape of these victories, a new term was coined, "the thin green line" of the Pacific Northwest.

Besides providing the tribes and public with the only regulatory means to evaluate projects, the terminals themselves can be a problem. In more than one case, terminal projects were proposed for locations impacting sensitive cultural resources, areas that provide salmon spawning or rearing habitat and other aquatic resources or were situated such that they directly impeded tribal treaty fisheries. Most of the terminals lie near water bodies, such as the Columbia River, adding or expanding dock infrastructure that attracts predators—both avian and aquatic—that impact treaty fisheries. Finally, the terminals' operations that involve transfer and storage of fossil fuel products, and these terminals' proximity to water bodies, increases risks of spill and injury to the river.

The variety of conveyances that feed these terminals and refineries all pose unique risks depending on location and product. Fossil fuels are conveyed via pipeline, long-haul truck, rail car, barge, and marine vessels throughout the Columbia River Basin. Oil and natural gas pipelines create risks of explosions and are often highly destructive to natural areas when constructed and are notoriously leaky during operation. Natural gas pipelines have been proven to pollute the air with methane, volatile

organic compounds, and particulate matter. In British Columbia, a proposed pipeline would bring heavy oil sands crude over fragile habitat and to the Salish Sea for transfer to oil tankers. Marine vessels pose their own elevated spill risks and have been shown to impact Southern Resident orcas and tribal fishing.

Rail has been in the Columbia River Basin for a very long time, hauling materials and supporting the regional economy for over a century. In the Columbia River Gorge, the rail lines both sides of the river, the construction and operation of which continues to directly—and often negatively—affect the hydrology and flow of the river. Long trains delay tribal access to fishing sites and create hazards to tribal members trying to exercise their treaty fishing. Adding more rail traffic increases the danger.

The amount of coal hauled through the Columbia River Gorge has been that minimally necessary to serve local generation.[136] When excessively large-scale coal storage and transport projects were proposed in the Pacific Northwest that would have substantially increased the number of coal trains severalfold, the tribes stood against these projects. Even with the smaller number of coal trains, many tribal fishers complained of coal dust in the windy Gorge. Coal dust contains arsenic and polycyclic aromatic hydrocarbons (PAHs), a known carcinogen. High levels of both contaminants have been found in the soil around coal piles, and arsenic can leach into water. Airborne coal dust has been associated with bronchitis, emphysema, and asthma. Burlington Northern Railroad estimates that each coal car loses 500 pounds of dust each trip, with each 100-car train potentially losing 50,000 pounds. With the specter of more coal trains, then, the tribes were adamantly opposed to this additional burden.

Meanwhile, in the Bakken fields of the Dakotas, the United States found itself in possession of large depositions of domestic crude. Oil companies looked west to markets in Asia and considered rail as the simplest form of conveyance to get the product to market. To this point, rail tanker cars had not been tested for light crude such as that from the Bakken fields. In 2013, an oil train derailed in Lac-Megantic, Quebec and exploded, killing forty-seven people and there were continual derailments and explosions, spilling more oil into rivers, lakes, and marine waters than in the previous forty years. New and retrofitted tank cars were developed that decreased the severity of the derailments, but nonetheless, spills occurred on an annual basis. Along with greater risks of high consequence spill events, the increase in oil terminal proposals meant a sharp increase in rail traffic. Most oil trains are made up of more than 100–120 cars, stretching a mile and a half. For the Columbia River, this meant long and numerous oil trains travelling both sides of the river, impeding tribal fishers' access and creating potentially dangerous conditions.

In the past, natural gas has been peddled as a clean-burning fuel less impactful to the environment than coal and crude oil, and a potential "bridge" fuel to move from fossil fuels to renewables. Riding this message, in recent years, the U.S. has become a global leader in natural gas extraction, mostly through fracking processes. However, fracking is extremely water intensive and when methods do not meet industry standards can contaminate drinking water. When natural gas is produced or transported, methane can leak into the

[136] In 2020, the PGE Boardman Coal Plant shuttered permanently and was the only coal plant in Oregon. Currently the TransAlta Coal Plant in Centralia, Washington is operating at reduced capacity and is slated for permanent closure in 2025.

© Flickr/Sarah Craig/Faces of Fracking CC BY-NC-ND 2.0

atmosphere. Methane is a potent greenhouse gas, with 34-80 times the warming power of carbon dioxide on a pound-for-pound basis (IPCC 2014).

In Canada, oil sands bitumen extraction is the most polluted and polluting extraction process of any fossil fuel, creating toxic waste and hazardous by-products like petroleum coke. The oil sands are located on Indigenous Nations' territories and extraction has destroyed thousands of acres of natural homelands and habitat.[137]

Overall, new fossil fuel projects have no place within any plan to protect salmon or treaty resources. Mitigation is often unavailable or inadequate, and most projects pose risks of irreparable physical consequences to cultural and natural resources.

RECOMMENDATION 40

Federal and state governments should end all subsidies for fossil fuels.

U.S direct subsidies to the fossil fuel industry are estimated at $20 billion per year. When externalities such as health, environmental, and climate factors are included, it is estimated the United States subsidizes fossil fuels to the tune of $649 billion per year. Eliminating fossil fuel subsidies would save taxpayer dollars while simultaneously reducing greenhouse gas emissions.[138] The fossil fuel industry also receives large tax breaks. The Biden Administration's 2022 budget proposes to eliminate $121 billion in tax breaks. The Department of the Treasury states "these oil, gas, and coal tax preferences distort markets by encouraging more investment in the fossil fuel sector than would occur under a more neutral tax system."[139]

The International Energy Agency and the Organization for Economic Co-operation and Development, an intergovernmental body in Paris, estimate that 52 advanced and emerging economies—representing about 90% of global fossil-fuel supplies—gave subsidies worth an average of $555 billion each year from 2017 to 2019.[140]

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[137] See, generally, https://www.theguardian.com/commentisfree/2015/jun/23/canadas-tar-sands-oil-fields-sacred-lands, https://www.nationalgeographic.com/environment/article/alberta-canadas-tar-sands-is-growing-but-indigenous-people-fight-back, https://www.ienearth.org/what-are-the-tar-sands/ (First Nations' subsistence food sources have diminished where habitat and entire ecosystems have been fatally disrupted by oil sands projects).

[138] See: https://www.eesi.org/papers/view/fact-sheet-proposals-to-reduce-fossil-fuel-subsidies-2021.

[139] *General Explanations of the Administration's Fiscal Year 2022 Revenue Proposals,* Department of the Treasury, May 2021.

[140] The Journal Nature, https://www.nature.com/articles/d41586-021-02847-2.

3.12 Carbon Dioxide Sequestration

RECOMMENDATION 41

Utilities, tribes, farming, and non-governmental organizations should implement pilot projects to sequester carbon dioxide.

There is great potential to reduce greenhouse gas emissions and improve carbon sequestration by changing forest and agricultural practices. The Confederated Tribes of the Warm Springs Reservation have a forest management program to sequester carbon and sell carbon offsets to others. The Nez Perce Tribe has Carbon Offset strategy to market Carbon Sequestration Credits. The program reinvests revenue from the sale of carbon to acquire previously forested lands and then replicate the process with additional reforestation projects (planting trees on land that was not previously forested). This effort contributes to the tribe's goal of acquiring former tribal lands. Subsequent carbon offset projects have included restoration of forests heavily damaged by wildfire and reforestation where past forest regeneration practices failed. APPENDIX D provides details on these activities.

Other examples include regenerative agricultural practices such as cover cropping and transitioning to no-till farming that trap carbon in the soil. These techniques were researched by the American Farm Trust in its report, *Combatting Climate Change on US Cropland.* This report provided a literature review of these two practices and describes a mapping tool that allows users to visualize and quantify greenhouse gas emissions reductions resulting from cropland and grazing land conservation management practices.

The American Farm Trust has expressed interest in partnering with tribes and others on carbon sequestration projects.

3.13 Nuclear Power

RECOMMENDATION 42

Northwest utilities should not consider new nuclear power missions at the Hanford Nuclear Reservation without tribal consultation and consent. Evaluation of other sites for nuclear fission should consider the costs and compatibility with intermittent renewable resources and salmon protections.

Several organizations in the Northwest utility have been exploring the development of new nuclear fission power reactors.[141] For example, X-energy has submitted a proposal to the U.S. Department of Energy to install several reactors on 22 acres of the Hanford Nuclear Reservation. The Confederated Tribes of the Umatilla Reservation "does not support the deployment of Small Modular Nuclear Reactors (SMR or

[141] https://www.seattletimes.com/seattle-news/environment/this-next-generation-nuclear-power-plant-is-pitched-for-washington-state-can-it-change-the-world/.

SMNR) or any new/additive nuclear [fission] missions at the Hanford Site".[142]

X-energy claims that these smaller reactors can be used for base load or load following. The website says these reactors operate at very high temperatures; cycling modules on and off several times a day to fill in times when low-cost solar and wind energy is not available will likely require diverting the steam output to other uses. These plants are also expected to have high capital costs. If they operate intermittently to follow load, the cost per kilowatt hour is likely to be higher than the recommended actions described above.

Any evaluation of this technology must address the full costs of these reactors, including the integration issues. Any consideration of new nuclear fission plants should also address waste storage, uranium mining effects and safety issues that have plagued the nuclear industry for more than 60 years. Permanent waste storage solutions for commercial nuclear waste have not been built. More than a quarter million metric tons of highly radioactive waste still sits in temporary storage near nuclear power plants and weapons production sites.

3.14 Stop Cryptocurrency Production in the Northwest

RECOMMENDATION 43

Utilities and Public Utility Commissions should adopt policy to deny service for cryptocurrency mining in the Northwest.

The process of mining and using cryptocurrency is energy-intensive due to the computer used in the process. The electricity and carbon dioxide impacts are alarming and harm salmon. A recent analysis showed that the four leading cryptocurrencies (Bitcoin, Ethereum, Bitcoin Cash, and Litecoin) use 164 million megawatt hours a year worldwide.[143] That is more electricity than 185 countries use and equal to 20 percent of the annual energy consumption in the United States.[144] The analysis estimates that over 115 million tons of carbon dioxide are emitted in these operations.

While data is limited, there are indications that the low electricity costs in the Northwest have attracted large cryptocurrency operations that consume large amounts of electricity and add to peak loads. These operations add costs and kill salmon; they do not provide any benefits to the Northwest. In fact, many of these cryptocurrency operations are Ponzi schemes where large investors get their money back when others buy into the system.

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[142] August 6, 2021 letter from CTUIR Chair Kathryn Brigham.

[143] https://www.moneysupermarket.com/gas-and-electricity/features/crypto-energy-consumption/?__cf_chl_jschl_tk__=pmd_8RUkZBCTQNCIDsLJr_Ur1t4_7BY8EpY8scGHti.XnQM-1635441682-0-gqNtZGzNAqWjcnBszQg9.

[144] https://www.eia.gov/energyexplained/electricity/electricity-in-the-us.php.

Utilities and public utility commissions should adopt policies to deny service to these operations because they damage the environment and salmon populations and many are scams that will harm small investors. If necessary, state legislatures may need to enact legislation. If it is not possible to deny service, then service should be made interruptible and only available when surplus electricity from renewable resources is available.

3.15 Climate Change Effects

Across the Pacific Northwest, changing environmental dynamics including weather patterns and air temperatures, river flow timing, flow source (snowpack or rainfed) and magnitude, and wildfire prevalence are impacting river temperatures. As these trends continue into the future, changing conditions are expected to have even more pronounced influences on water temperature.

The Columbia and Snake River dams amplify these thermal risks by dramatically slowing the water, creating a large surface area intensifying solar irradiation, and creating a heat trap for both warm and cool water flowing into the system of mainstem reservoirs. These changes in river temperatures are expected to affect the health, behavior, and survival of cold-water fish at both the individual and population scale. Where increased river temperatures result in exposure to temperatures above the optimal range for Columbia River salmon, impacts can include increased heat stress and migration delays, among other direct and indirect effects. In downstream mainstem waters where large areas of contiguous cold water are absent, cold-water refuges may play an increasingly important role in mitigating the effects of exposure to temperatures that exceed fish thermal tolerance thresholds.[145]

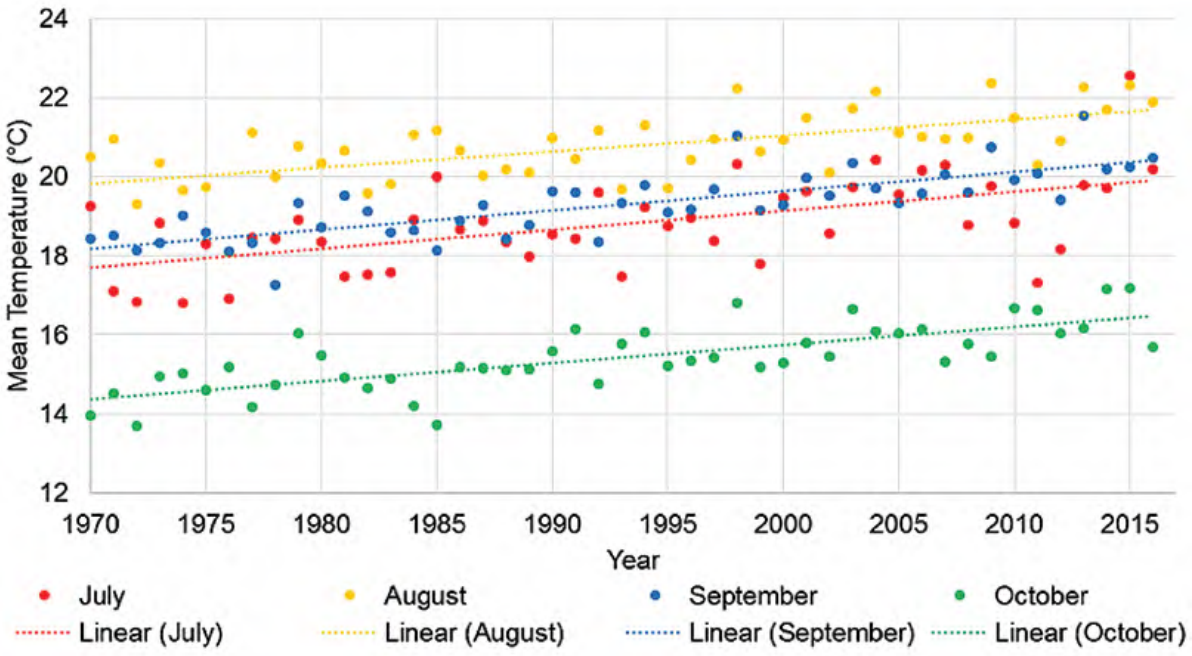
On May 18, 2020, EPA established the *Columbia and Lower Snake Rivers Temperature Total Maximum Daily Load (TMDL)* as required by Section 303(d) of the Clean Water Act and its implementing regulations (Title 40 of the Code of Federal Regulations, Section 130.7). Spanning almost 900 river miles, the TMDL examines sources of temperature impairments on the Columbia River from the Canadian border to the Pacific Ocean, and on the lower Snake River in Washington from its confluence with the Clearwater River at the Idaho border to its confluence with the Columbia River. The TMDL is required under the federal Clean Water Act because significant portions of the Columbia and lower Snake Rivers are identified by the states of Washington and Oregon as impaired due to temperatures that exceed the numeric criteria portion of the states' water quality standards at various locations and times of year.

EPA's TMDL report synthesized available records of river temperatures and estimated warming due to climate change that has occurred to date and warming that is projected to occur in the future (TMDL, Appendix G). EPA's reports evidence of a warming trend in river temperatures since 1960 that ranges from 0.2°C to 0.4°C per decade for a total water temperature increase to data of 1.5°C ±0.5°C.[146] As noted previously, lethal effects from

[145] https://www.epa.gov/system/files/documents/2021-08/tmdl-columbia-snake-temperature-appendix-g.pdf

[146] Available at https://www.epa.gov/columbiariver/tmdl-temperature-columbia-and-lower-snake-rivers.

FIGURE 21. Trend in Monthly Mean Temperatures at Bonneville Dam



thermal exposure for most salmonids have been found to range from 23°C to 27°C (McCullough, 1999, 2001).

In addition to the chronic effects of increasing baseline river temperatures, acute exceedances of thermal tolerance maxima occurred more frequently in recent years and are projected to be of increasing magnitude and frequency (Isaak et al. 2018). One recent example of extreme Columbia River basin temperatures occurred in 2015, when temperatures in early June reached in excess of 21°C weeks earlier than is typical and remained 2°C–4°C above monthly average temperatures for several weeks, contributing to a mass die-off of sockeye salmon in the Columbia and Snake Rivers (Isaak et al. 2018, NMFS 2016). Approximately 14% of the sockeye salmon that passed through the Bonneville Dam were detected upstream at McNary dam on the Columbia River, while on average 68% were detected the previous five years (NMFS 2016). In general, the first and last dates in each calendar year on which water temperatures exceed 20°C at Bonneville Dam are occurring earlier and later than they have historically (National Research Council 2004).[147]

The following climate change effects also need to be addressed alongside potential Columbia River System actions:

1. Projected changes to river flow and temperature under future climate change scenarios *(readily available in recent scientific literature and policy documents, supported by regional modeling efforts).*

[147] *Id.*

2. Potential adjustments to hydro regulation *(discussed in the RMJOCII report recently published by the action agencies).*
3. Considerations for Columbia River fish populations *(discussed in recent scientific literature with primary effects being higher winter flows, an earlier spring freshet, lower flows and higher water temperature during the summer, with these effects varying by subbasin).*
4. Synchronous effects on energy demand *(discussed in recent presentation by the NW Power and Conservation Council, with the primary effect being a projected increase in summer energy demand for air conditioning and a projected decrease in winter energy demand for heating).*

3.16 Conclusion

The Northwest is at a critical crossroads, facing challenges to the health of the planet and the future of salmon, other tribal foods and iconic fish and wildlife. These challenges are especially important to tribal resources that have sustained tribal people since time immemorial.

One path leads to affordable, carbon-free energy that harmonizes with the ecosystem and helps restore salmon. This future would prioritize energy efficiency, renewable resources, new storage technologies, reductions in peak loads, and other strategies that are compatible with the needs of fish and wildlife. These efforts would reduce the impacts of renewable resource projects and transmission lines on tribal resources and save consumers money.

The other path creates conflicts between renewable resources and tribal resources and results in higher costs for consumers.

Choosing the first path will require the courage to act, common-ground solutions, and a commitment of resources to accomplish the hard work ahead. It will also require the humility to periodically evaluate and adjust course based on new information and understanding.

CRITFC and its member tribes are committed to working with other regional interests to lead the region to a brighter and healthier future. Our people and the resources that sustain them depend on it.

Energy Vision Glossary

We have tried to minimize jargon and acronyms in the Energy Vision, but we have not always been successful. This glossary may help readers as they read the document.

Average Energy	Amount a resource can produce over an entire year. For example, a wind farm might have a total capacity to generate 100 MW, but the wind blows during only a third of the year, so the total average energy would be 33 aMW.
aMW	Average megawatts—for example, the amount of electricity generated or used on average over a year. For comparison, Seattle uses about 1,000 aMW during a year.
BPA	Bonneville Power Administration
Capacity	Amount a resource can generate at peak production
CRSO	Columbia River System Operations
CTUIR	Confederated Tribes of the Umatilla Indian Reservation
CTWSRO	Confederated Tribes of the Warm Springs Reservation of Oregon
Corps	U.S. Army Corps of Engineers
Council	Northwest Power and Conservation Council
Federal Action Agencies	Bonneville Power Administration, U.S. Army Corps of Engineers and U.S. Bureau of Reclamation
GW	Gigawatts—a thousand megawatts
kcfs	One thousand cubic feet per second of water flow
MW	Megawatt
NPCC	Northwest Power and Conservation Council
NPT	Nez Perce Tribe
Reclamation	U.S. Bureau of Reclamation
TMDL	Total maximum daily load. It is a regulatory term in the U.S. Clean Water Act, describing a plan for restoring impaired waters that identifies the maximum amount of a pollutant that a body of water can receive while still meeting water quality standards.
YN	Confederated Tribes and Bands of the Yakama Nation

Acknowledgements

CRITFC Staff

A number of CRITFC staff contributed to this document, led by **Rob Lothrop** and **Chris Golightly**. Several staff drafted sections or contributed expertise, including **Dianne Barton**, **Julie Carter**, **Kyle Dittmer**, **Jeremy FiveCrows**, **Laura Gephart**, **David Graves**, **Jim Heffernan**, **Sanjeev Joshi**, **Tom Lorz**, and **Tom Skiles**.

CRITFC's member tribes and their staff also provided valuable comments.

Principal Authors

We also appreciate the work by **Ed Sheets** and **Margie Schaff** to draft major portions of this Energy Vision.

Sheets also assisted in the development of the 2013 Energy Vision and has worked on regional energy and environmental issues since 1975, including work on the Northwest Power Act with the late Senator Warren Magnuson, director of the Washington State Energy Office, and founding executive director of the Northwest Power and Conservation Council (see: www.edsheets.com).

Schaff has assisted numerous tribes on energy development and policy issues. She has worked for the Western Area Power Administration and for almost 30 years has operated her own law firm, currently Margaret Schaff & Associates, LLC.

Energy Experts

CRITFC also appreciates the consultants who provided invaluable advice and made significant contributions to this Energy Vision.

- **Tom Eckman** was the power division director at the Northwest Power and Conservation Council and worked for the Council for 34 years on energy efficiency and resources. He has also been instrumental in developing regional and national energy efficiency standards.
- **Tom Foley** was a principal author of the 2003 and 2013 Energy Visions. He worked as the energy resources manager at Northwest Power and Conservation Council and is a former board chair of the Energy Trust of Oregon.
- **Randy Hardy** was the CEO of BPA and Seattle City Light. He served as executive director of the Pacific Northwest Utilities Conference Committee and worked at the Federal Energy Administration. Hardy Energy provides advice to utilities, wind/renewable generators, and other organizations (see: www.hardyenergy.com).
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Reviewers

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- **Mark Bagdovitz,** U.S. Fish and Wildlife Service
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- **Denis Hayes,** President, Bullitt Foundation
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- **Ken Johnston,** Bonneville Power Administration (BPA)
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- **Todd True,** Earth Justice
- **Stefanie Tsosie,** Earth Justice
- **John Volkman,** former general counsel for the Northwest Power and Conservation Council and Energy Trust of Oregon, and former counsel for NOAA Fisheries
- **Bryce Yonkers,** Grid Forward

In our stories, the Celilo Falls are the remains of the dam built by the five Swallow Sisters to block salmon from returning upriver. Coyote tricked the sisters, destroyed the dam, and the resulting flood left the falls and the rocky, contorted riverbed downstream. As punishment for keeping salmon from the people, Coyote ordered swallows to fly up the river each spring to announce the return of salmon. To this day, the migration of swallows marks the spring salmon migration.

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APPENDIX A:

Background

Populations of Columbia and Snake River salmon and steelhead are at very dangerous levels for their continued existence. Forty-two percent of Snake River wild-origin spring/summer Chinook populations have fewer than 50 fish. Current salmon and steelhead populations are at about 75% of the lowest goal recently set by a regional task force.

Vision for the Columbia River Basin Resources

CRITFC member tribes envision a future where the Columbia Basin electric power system supports abundant and sustainable fish and wildlife populations, protects tribal cultural resources, and provides reliable and affordable electricity.

The Yakama, Nez Perce, Umatilla, and Warm Springs tribes each secured, by treaty, rights to take fish that pass their usual and accustomed fishing places. Numerous federal court decisions have affirmed these rights.[148] For more information on the treaties please see APPENDIX A. The treaties did not only secure the right to take fish but assured the tribes that the fish would be there to harvest.[149]

The four tribes founded CRITFC in 1977 to protect the member tribes' treaty rights to take salmon; CRITFC's mission is "to ensure a unified voice in the overall management of the fishery resources, and as managers, to protect reserved treaty rights through the exercise of the inherent sovereign powers of the tribes."

For the tribes and CRITFC to accomplish their mission, salmon, steelhead, sturgeon, Pacific lamprey, and mussel populations need to be rebuilt. The dams on the Columbia and Snake rivers continue to be the main obstacle to anadromous and resident fish restoration. Climate change will compound the effects of the dams.

The people of the Yakama, Nez Perce, Umatilla, and Warm Springs tribes have always shared a common understanding—that their very existence depends on the respectful use of the Columbia River Basin's vast land and water resources. Indeed, their very souls and spirits were and are inextricably tied to the natural world and its myriad inhabitants.[150] Among those inhabitants, none were more important than the

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[148] *E.g. Sohappy v. Smith*, 302 F.Supp. 899 (D.Or. 1969), aff'd, *United States v. Oregon,* 529 F.2d 570 (9th Cir. 1976); *Washington v. Washington State Commercial Passenger Fishing Vessel Ass'n*, 443 U.S. 658 (1979); *United States v. Winans,* 198 U.S. 371 (1905); *Confederated Tribes of the Umatilla Indian Reservation v. Alexander,* 440 F.Supp. 553 (D.Or. 1977).

[149] https://www.critfc.org/wp-content/uploads/2021/11/Treaty-Rights-list.pdf.

[150] In our stories, the Celilo Falls are the remains of the dam built by the five Swallow Sisters to block salmon from returning upriver. Coyote tricked the sisters, destroyed the dam, and the resulting flood left the falls and the rocky, contorted riverbed downstream. As punishment for keeping salmon from the people, Coyote ordered swallows to fly up the river each spring to announce the return of salmon. To this day, the migration of swallows marks the spring salmon migration.

teeming millions of anadromous fish enriching the basin's rivers and streams.

Despite some differences in language and cultural practices, the people of these tribes shared the foundation of a regional economy based on salmon. To the extent the resource permits, tribal people continue to fish for ceremonial, subsistence, and commercial purposes employing—as they always have—a variety of technologies.

Today, perhaps even more than in the past, the Columbia River treaty tribes are brought together by the struggle to save the salmon and by shared spiritual traditions such as the first salmon feast.

A Tribal Energy Vision for the Columbia River Basin

CRITFC adopted the original Energy Vision in 2003. It called for a series of actions to avoid another energy crisis and lift some of the burden of the region's energy supply from the Columbia River. A decade later, we looked back on actions that were taken and proposed new actions in a 2013 update to the Energy Vision.

One of the most important aspects of restoring salmon and ensuring their resiliency to withstand energy and environmental catastrophes like that which occurred in 2001 is the continued investment of the region in fish and wildlife

protection, mitigation, and enhancement. In this regard, BPA is an unrivaled leader.[151] The 2003 Energy Vision did not address discrete fish mitigation measures. Rather it is a vision for a long-term regional energy system that places a lesser burden on the fish and wildlife that depend on the Columbia River and its tributaries, while protecting tribal First Foods and cultural resources found in upland areas.

The Columbia and Snake Rivers' dams are an integral part of the Northwest and West Coast power systems. Power generated from these rivers has been a cheap, dominant part of the power system, providing energy, capacity, ancillary services, system stability, and more. However, the low-dollar cost of hydropower does not fully reflect the huge economic, cultural, and environmental costs incurred by tribes and others.

These tribes based their living on resources of the rivers, including fish, wildlife, and water quality for thousands of years prior to the construction of the hydropower system. Before the first dam was built, salmon and steelhead numbered in the tens of millions of fish. The tribes' economies relied on those fish for their prosperity. Currently there are fewer than 1 million natural fish remaining in the Columbia River. The costs to tribes of development of the Northwest's hydropower system represent a classic case of "negative externalities." Because tribal non-market resources have not been "priced", they often have been treated in energy planning as if their cost were zero and their availability limitless. They are not. Treating them in such a way is economic malpractice. More importantly it does not recognize the trust and treaty obligations that the United States carries with regard to the tribes.

By careful energy planning and appropriate action, the region can use the Basin's river systems to meet the needs for fish, wildlife, and water quality while supplying reliable energy services.

New challenges and opportunities are being faced by energy planners that did not exist ten years ago. And our understanding of climate change has advanced significantly. State of the art climate models predict future changes in the annual cycle of Columbia River flows and regional temperatures. Addressing climate change causes and response is a very high priority for the tribes. Among other things, the recommendations for low-cost energy efficiency and renewable resources in this Energy Vision for the Columbia River Basin will reduce the need for power plants that emit greenhouse gases. The Vision's goals for greenhouse gas reductions are consonant with the goals set by California, Oregon, and Washington, but the Vision offers alternative means of implementation.

The 2003 *Energy Vision for the Columbia River*[152] described solutions to address the conflict between peak power production and Columbia Basin salmon. Against the backdrop of fish problems associated with serving peak loads, that plan identified less harmful and less expensive ways to provide electricity for peak loads. A win-win combination. The 2013 *Energy Vision for the Columbia River*[153] was built on the recommendations made in 2003. The 2022 *Energy Vision for the Columbia River Basin* builds on these predecessors.

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[151] In 2008, the Commission and three of its member tribes signed a ten-year Fish Accords Agreement with BPA guaranteeing funding for discrete actions. The Accords provide funding for a significant number of projects to rebuild fish and wildlife.

[152] https://www.critfc.org/blog/documents/tribal-energy-vision-for-the-columbia-river-2003/

[153] https://www.critfc.org/wp-content/uploads/2021/02/2013-Energy-Vision-Review-Draft-.pdf

"My strength is from the fish; my blood is from the fish, from the roots and berries. The fish and game are the essence of my life. I was not brought from a foreign country and did not come here. I was put here by the Creator."

— Chief Meninock, Yakama, 1915

APPENDIX B:

Resolutions, Affiliated Tribes of Northwest Indians, and National Congress of American Indians

2021 Virtual Mid-Year Convention

RESOLUTION #2021 – 23

"CALLING ON THE PRESIDENT OF THE UNITED STATES AND THE 117TH CONGRESS TO SEIZE THE ONCE-IN-A-LIFETIME CONGRESSIONAL OPPORTUNITY TO INVEST IN SALMON AND RIVER RESTORATION IN THE PACIFIC NORTHWEST, CHARTING A STRONGER, BETTER FUTURE FOR THE NORTHWEST, AND BRINGING LONG-IGNORED TRIBAL JUSTICE TO OUR PEOPLES AND HOMELANDS"

PREAMBLE

We, the members of the Affiliated Tribes of Northwest Indians of the United States, invoking the divine blessing of the Creator upon our efforts and purposes, in order to preserve for ourselves and our descendants rights secured under Indian Treaties, Executive Orders and benefits to which we are entitled under the laws and constitution of the United States and several states, to enlighten the public toward a better understanding of the Indian people, to preserve Indian cultural values, and otherwise promote the welfare of the Indian people, do hereby establish and submit the following resolution:

WHEREAS, the Affiliated Tribes of Northwest Indians (ATNI) are representatives of and advocates for national, regional, and specific tribal concerns; and

WHEREAS, ATNI is a regional organization comprised of American Indians/Alaska Natives and tribes in the states of Washington, Idaho, Oregon, Montana, Nevada, Northern California, and Alaska; and

WHEREAS, the health, safety, welfare, education, economic and employment opportunity, and preservation of cultural and natural resources are primary goals and objectives of ATNI; and

WHEREAS, the Tribes of ATNI are united by salmon; by the Northwest rivers that salmon, steelhead, lamprey, and native fish depend upon; and by the interconnectedness of salmon with their ecosystems – from the orca in the ocean and Puget Sound to the nutrients salmon supply to the furthest inland streams; and

WHEREAS, the United States used federal legislation and executive orders to take land from tribal peoples, and tribes ceded most of their land through treaties but reserved certain rights to protect their cultural way of life; and

WHEREAS, tribal cultures and lifeways are rooted in place and tied to their homelands, but tribes cannot just relocate to access traditional resources; and

WHEREAS, the modern Northwest with its massive irrigation, hydropower, and storage systems was built on the backs of tribal peoples from the 1930s on, through the use and destruction of the lands, rivers, and fisheries we have lived with for thousands of years; and

WHEREAS, the United States shares a unique relationship with the Tribes of ATNI, with the United States being bound to honor the obligations to tribes made in Treaties, Executive Orders, adjudicated through numerous federal court decisions and its trust responsibility to tribal sovereign nations; and

WHEREAS, the fate of our Tribes and the Northwest salmon are intertwined; and

WHEREAS, in the Columbia Basin, the Northwest Power Act and its promise of "equitable treatment" for energy and fish and wildlife did prevent the mid-Columbia fall chinook from being listed under the Endangered Species Act (ESA) but failed to prevent the subsequent listings of salmon and steelhead under the ESA; and

WHEREAS, U.S. District Court Judge Michael Simon in his 2016 ESA and National Environmental Policy Act (NEPA) ruling – rejecting the federal government's salmon plan for the Columbia River System dams for the fifth time – emphasized that the Federal Columbia River System remains a system literally crying out for a major overhaul, as Judge Marsh observed twenty years earlier; and

WHEREAS, the prior Administration's 2020 salmon plans in response to Judge Simon's ruling – the 2020 Columbia River System Environmental Impact Statement (EIS), Biological Opinion (BiOp), and Record of Decision (ROD) – were politicized with election-driven timelines, and used the prior Administration's weakened NEPA and ESA regulations to justify flawed conclusions and attempt to lock in inadequate dam operations for the next 15 years; and

WHEREAS, Columbia Basin Tribes expressed special concerns with the prior Administration's Columbia River System EIS with respect to its inadequate consideration of Tribal rights, interests, resources, trust lands; its failure to reveal environmental and social justice system impacts on Tribes; its failure to address fish restoration above dams that block fish passage; and its inadequate consideration of the impacts of climate warming; and

WHEREAS, the new Administration and the 117th Congress face a once-in-a-lifetime opportunity – a historical legacy moment – to secure congressional funding to invest in salmon recovery and river restoration throughout the Northwest; and

WHEREAS, Tribes throughout the Columbia Basin have supported Congressman Mike Simpson's initiative and his "Columbia Basin Initiative" legislative proposal for:

- Identifying this historic moment and opportunity;

- Engaging with Tribes directly and regularly;
- Emphasizing the very real and imminent salmon extinction crisis;
- Recognizing a singular, generational legislative moment, because of the current Administration and current leadership in the Senate and the House, and that this is a moment for action, not for more process;
- Offering a comprehensive framework that embraces actions that have been longstanding priorities for Tribes throughout the Basin: restoring the lower Snake River by breaching the four lower Snake River dams and optimizing spill to benefit salmon at the mainstem federal Columbia River Dams; restoring salmon behind blocked areas in the Upper Columbia and Upper Snake basins; and ensuring that Tribes and State co-managers become responsible for implementing salmon restoration;
- Offering a solution that invests in a stronger, better Northwest that goes beyond salmon, ensuring that communities impacted by river restoration are made whole – and in doing so offering additional opportunities for Tribes within other sectors – from infrastructure and technology development to energy production;
- Highlighting that an interest-based solution will involve legal certainty;
- Engaging in a bipartisan manner against the backdrop of these foundational elements;
- Speaking the truth that failure to act this critical historical moment will be looked back on as the tragedy of the extinction of Snake River salmon populations; and

WHEREAS, the status of Columbia Basin salmon and steelhead species is dire and getting worse, with many populations of Snake River spring Chinook salmon and steelhead on a steep slope to extinction; the point where populations become doomed to extinction is identified by biologists as the Quasi-Extinction Threshold (QET); and

- right now, 42% of the Snake Basin spring/summer Chinook populations are at or below the QET; that is, 50 natural origin spawners or less on the spawning grounds for four consecutive years; and
- 77% of the populations are predicted to drop below the QET level by 2025; and

WHEREAS, time may be even shorter as climate warming advances, and restoring the lower Snake (now a series of slow-moving, easily warmed lakes) to a naturally flowing river that connects fish to cold, high-altitude, near-pristine Salmon and Clearwater Basin habitat is exactly what is needed for the best possible ecological resilience to warming temperatures; and

WHEREAS, tribal initiatives to restore salmon behind dams that block fish passage in the Upper Columbia and Upper Snake River have been limited by availability of funding and assertions of inadequate authorizations; and

WHEREAS, on April 14-15, 2021, the Columbia River Tribes gathered and reached agreement on a set of "common ground" principles underlying their support for Congressman Simpson's Columbia Basin Initiative:

- The true wealth of our region begins with the health of our rivers, fish, and the ecosystem they support, which is our culture, history and future;
- Agriculture is an important part of our region's economy;
- Affordable and reliable power is important to regional families and businesses, tribal and non-tribal;
- Providing legal certainty for the vast majority of federal dams in the Columbia/Snake River basins is a necessary element of a lasting solution;
- A significant federal infrastructure investment in alternative energy and transportation provides a unique opportunity to restore salmon while keeping power affordable and maintaining agricultural commerce;
- A comprehensive legislative solution is preferable to all other avenues and is urgently needed;
- The time for action is now. The Columbia Basin cannot become another Klamath Basin crisis; and

WHEREAS, the Southern Resident orcas of Puget Sound, a being sacred to many Northwest Tribes, are starving to death because culverts and dams that block and impair Chinook salmon migrations are limiting the orcas' food source; and Governor Inslee's Orca Recovery Task Force recommended – in addition to other dam and culvert removals – reviewing the need to breach the four lower Snake River dams to help recover the struggling Puget Sound orcas, which resulted in the Lower Snake River Dams Stakeholder Engagement Report and informed Washington's statement of management goals and principles for the Columbia and Snake rivers:

- Protecting and restoring abundant, harvestable salmon and steelhead and other native fish species, including contributing to a reliable source of prey for southern resident orcas;
- Honoring tribal rights, including a future for salmon that supports tribes' cultural, spiritual, and economic needs;
- Providing for a clean, affordable, and reliable energy system that meets our clean energy and climate goals;

- Ensuring affordable and reliable transportation alternatives for wheat farmers in the Palouse and Tri-Cities areas

- Ensuring reliable irrigation supplies for eastern Washington farms; and

WHEREAS, implementation of federal court rulings upholding Treaty-reserved fishing rights and ordering the state of Washington to replace culverts that block fish passage require funding to implement, as do other Tribal habitat, hatchery, and salmon restoration efforts; and

WHEREAS, ATNI stands united in supporting investment in salmon and river restoration in the Northwest; now

THEREFORE BE IT RESOLVED, that ATNI calls on the President of the United States (POTUS) and the 117th Congress to ensure that funding is set aside now at this critical ecological juncture for salmon and orca, to implement the bold actions for salmon and river restoration identified in the framework of Congressman Simpson's Energy and Salmon legislative proposal, including restoring the lower Snake River by breaching the four lower Snake River dams; and

BE IT FURTHER RESOLVED that ATNI requests the POTUS and 117th Congress to ensure that the salmon restoration priorities of the Tribes of ATNI are prioritized and funded; and

BE IT FURTHER RESOLVED that ATNI calls for the timely convening of a Northwest Tribal Salmon and Orca Summit, at an ATNI location, with invitations to Presidential Administration Officials and to Northwest Congressional Delegation Members, to meet and take timely action with respect to the salmon and orca restoration priorities of the Tribes of ATNI; and

BE IT FURTHER RESOLVED, that ATNI requests the POTUS to prioritize working on the actions for salmon and river restoration identified as the framework of Congressman Simpson's Energy and Salmon legislative proposal, and withdraw any federal court defense of the prior Administration's flawed 2020 Columbia River System EIS, BiOp, and ROD as otherwise a defense of methods and conclusions inconsistent with the new Administration's environmental and tribal principles and priorities; and

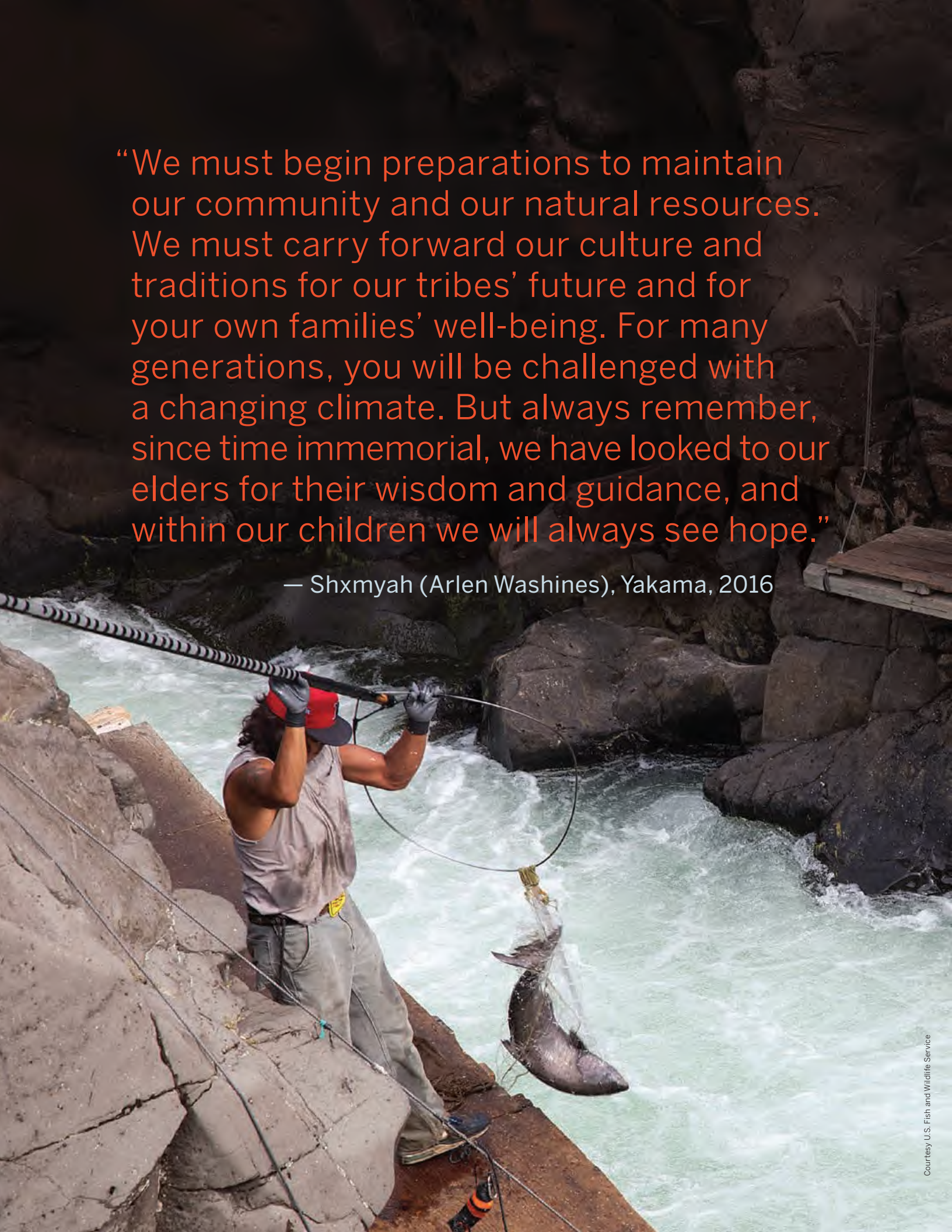
BE IT FINALLY RESOLVED, that this resolution be forwarded to the National Congress of American Indians.

CERTIFICATION

The foregoing resolution was adopted at the 2021 Virtual Mid-Year Convention of the Affiliated Tribes of Northwest Indians, Portland, Oregon, on May 24 – May 27, 2021, with a quorum present.

Leonard Forsman, President

Norma Jean Louie, Secretary



"We must begin preparations to maintain our community and our natural resources. We must carry forward our culture and traditions for our tribes' future and for your own families' well-being. For many generations, you will be challenged with a changing climate. But always remember, since time immemorial, we have looked to our elders for their wisdom and guidance, and within our children we will always see hope."

— Shxmyah (Arlen Washines), Yakama, 2016

Courtesy U.S. Fish and Wildlife Service

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The National Congress of American Indians
Resolution #AK-21-009

TITLE: Calling On The President and Congress to Invest in Salmon And River Restoration In The Pacific Northwest

WHEREAS, we, the members of the National Congress of American Indians of the United States, invoking the divine blessing of the Creator upon our efforts and purposes, in order to preserve for ourselves and our descendants the inherent sovereign rights of our Indian nations, rights secured under Indian treaties and agreements with the United States, and all other rights and benefits to which we are entitled under the laws and Constitution of the United States and the United Nations Declaration on the Rights of Indigenous Peoples, to enlighten the public toward a better understanding of the Indian people, to preserve Indian cultural values, and otherwise promote the health, safety and welfare of the Indian people, do hereby establish and submit the following resolution; and

WHEREAS, the National Congress of American Indians (NCAI) was established in 1944 and is the oldest and largest national organization of American Indian and Alaska Native tribal governments; and

WHEREAS, many of the Tribal Nations of NCAI are united by salmon; by the Northwest rivers that salmon, steelhead, lamprey, and other native fish depend upon; and by the interconnectedness of salmon with their ecosystems – from the orca in the ocean and Puget Sound, to the nutrients salmon supply to the furthest inland streams; and

WHEREAS, through legislation and executive orders, the United States took land from tribal peoples. Tribal Nations also ceded lands through treaties, but in so doing reserved certain rights to protect their cultural way of life; and

WHEREAS, Tribal cultures and lifeways are deeply rooted in place and tied to their homelands. As such Tribal Nations cannot simply relocate to access traditional resources or ceremonial places; and

WHEREAS, beginning in the 1930s, and through the use and destruction of the lands, rivers, and fisheries Tribal Nations have lived with for thousands of years, the modern Northwest is a maze of massive irrigation, hydropower, and storage systems built on the backs of Tribal peoples ; and

WHEREAS, the United States has a unique political relationship with Tribal Nations. Through this special relationship, the United States is bound to honor the obligations it has made in Treaties, Executive Orders, adjudicated through numerous federal court decisions, and its trust responsibility to sovereign Tribal Nations; and

WHEREAS, the fate of many Tribal Nations and the Northwest salmon are intertwined; and

WHEREAS, in the Columbia Basin, the Northwest Power Act and its promise of "equitable treatment" for energy and fish and wildlife did prevent the mid-Columbia fall chinook from being listed under the Endangered Species Act (ESA) but failed to prevent the subsequent listings of salmon and steelhead under the ESA; and

WHEREAS, U.S. District Court for Oregon in its 2016 ESA and National Environmental Policy Act (NEPA) ruling (*Nat'l Wildlife Fed'n v. Nat'l Marine Fisheries Serv.*, 186 F.Supp 3d. 861 (D. Or. 2106)) – rejecting the federal government's salmon plan for the Columbia River System dams for the fifth time emphasized that the Federal Columbia River System remains a system literally crying out for a major overhaul, as that Court observed twenty years earlier in the same case; and

WHEREAS, the prior Administration's 2020 salmon plans in response to Oregon District Court's 2016 ruling – the 2020 Columbia River System Environmental Impact Statement (EIS), Biological Opinion (BiOp), and Record of Decision (ROD) – were politicized with election-driven timelines, and used the prior Administration's weakened NEPA and ESA regulations to justify flawed conclusions and attempt to lock in inadequate dam operations for the next 15 years; and

WHEREAS, Columbia Basin Tribes expressed special concerns with the prior Administration's Columbia River System EIS with respect to its inadequate consideration of Tribal rights, interests, resources, trust lands; its failure to reveal environmental and social justice system impacts on Tribes; its failure to address fish restoration above dams that block fish passage; and its inadequate consideration of the impacts of climate warming; and

WHEREAS, Tribal Nations and Congress has a once-in-a-lifetime opportunity – a historical legacy moment – to secure funding to invest in salmon recovery and river restoration throughout the Northwest; and

WHEREAS, Tribal Nations throughout the Columbia Basin have supported legislative proposals that:

- Engage with Tribal Nations directly and regularly;
- Emphasize the very real and imminent salmon extinction crisis;
- Recognize a singular, generational legislative moment, because of the current Administration and current leadership in the Senate and the House, and that this is a moment for action, not for more process;
- Offer a comprehensive framework that embraces actions that have been longstanding priorities for Tribes throughout the Basin: restoring the lower Snake River by breaching the four lower Snake River dams and optimizing spill to benefit salmon at the mainstream federal Columbia River Dams; restoring salmon behind blocked areas in the Upper Columbia and Upper Snake basins; and ensuring that Tribes and State co-managers become responsible for implementing salmon restoration;

- Offer a solution that invests in a stronger, better Northwest that goes beyond salmon, ensuring that communities impacted by river restoration are made whole – and in doing so offering additional opportunities for Tribes within other sectors – from infrastructure and technology development to energy production;
- Highlights that an interest-based solution will involve legal certainty;
- Engages in a bipartisan manner against the backdrop of these foundational elements;
- Speaks the truth that failure to act this critical historical moment will be looked back on as the tragedy of the extinction of Snake River salmon populations; and

WHEREAS, the status of Columbia Basin salmon and steelhead species are dire and getting worse. Many populations of Snake River spring Chinook salmon and steelhead at the tipping point of extinction – identified by biologists as the Quasi-Extinction Threshold (QET);

- 42% of the Snake Basin spring/summer Chinook populations are at or below the QET; that is, 50 natural origin spawners or less on the spawning grounds for four consecutive years;
- 77% of the populations are predicted to drop below the QET level by 2025; and

WHEREAS, climatic warming shortens the time to act. Restoring the lower Snake (now a series of slow-moving, easily warmed lakes) to a naturally flowing river that connects fish to cold, high-altitude, near-pristine Salmon and Clearwater Basin habitat is the best possible solution for ecological resilience to warming temperatures; and

WHEREAS, the initiatives of Tribal Nations to restore salmon behind dams that block fish passage in the Upper Columbia and Upper Snake River have been limited by availability of funding and assertions of inadequate authorizations; and

WHEREAS, on April 14-15, 2021, the Columbia River Tribes gathered and reached agreement on a set of "common ground" principles underlying their support for Congressman Simpson's Columbia Basin Initiative:

- The true wealth of our region begins with the health of our rivers, fish, and the ecosystem they support, which is our culture, history and future;
- Agriculture is an important part of our region's economy;
- Affordable and reliable power is important to regional families and businesses, tribal and non-tribal;
- Providing legal certainty for the vast majority of federal dams in the Columbia/Snake River basins is a necessary element of a lasting solution;
- Providing legal certainty for the vast majority of federal dams in the Columbia/Snake River basins is a necessary element of a lasting solution;

- A significant federal infrastructure investment in alternative energy and transportation provides a unique opportunity to restore salmon while keeping power affordable and maintaining agricultural commerce;

- A comprehensive legislative solution is preferable to all other avenues and is urgently needed;

- The time for action is now. The Columbia Basin cannot become another Klamath Basin crisis; and

WHEREAS, the Southern Resident orcas of Puget Sound that are sacred to many Northwest Tribes, are starving to death because culverts and dams block and impair Chinook salmon migrations and limit the orcas' food source; and Governor of the State of Washington's Orca Recovery Task Force recommended – in addition to other dam and culvert removals – reviewing the need to breach the four lower Snake River dams to help recover the struggling Puget Sound orcas, which resulted in the Lower Snake River Dams Stakeholder Engagement Report and informed Washington States' statement of management goals and principles for the Columbia and Snake rivers:

- Protecting and restoring abundant, harvestable salmon and steelhead and other native fish species, including contributing to a reliable source of prey for southern resident orcas;

- Honoring Tribal rights, including a future for salmon that supports Tribal cultural, spiritual, ceremonial, subsistence, and economic needs;

- Providing for a clean, affordable, and reliable energy system that meets our clean energy and climate goals;

- Ensuring affordable and reliable transportation alternatives for wheat farmers in the Palouse and Tri-Cities areas;

- Ensuring reliable irrigation supplies for eastern Washington farms; and

WHEREAS, implementation of federal court rulings upholding Treaty-reserved fishing rights and ordering the state of Washington to replace culverts that block fish passage require funding to implement, as do Tribal habitat, hatchery, and salmon restoration efforts; and

WHEREAS, NCAI stands united in supporting investment in salmon and river restoration in the Northwest and throughout Indian Country.

NOW THEREFORE BE IT RESOLVED, that the National Congress of American Indians (NCAI) calls on the Executive Branch and Congress to ensure that funding is set aside now at this critical ecological juncture for salmon and orca, to implement the bold actions for salmon and river restoration identified in the framework of the Columbia Basin Initiative legislative proposal, including restoring the lower Snake River by breaching the four lower Snake River dams; and

BE IT FURTHER RESOLVED, that NCAI requests the Executive Branch and Congress ensure that Tribal species restoration actions are prioritized and fully funded; and

BE IT FURTHER RESOLVED, that NCAI calls for the timely convening of a Tribal Salmon and Orca Summit, at an NCAI location, with invitations to Executive Branch Officials and to Congressional Members, to meet and take timely action with respect to the salmon and orca restoration priorities of Tribal Nations; and

BE IT FURTHER RESOLVED, that NCAI requests the Executive Branch and Congress prioritize working on actions to protect salmon, and other culturally and economically important fish and wildlife, and river restoration actions, and withdraw any federal court defense of the prior Administration's 2020 Columbia River System EIS, BiOp, and ROD's and other environmental decisions that are inconsistent with Tribal environmental principles and priorities; and

BE IT FINALLY RESOLVED, that this resolution shall be the policy of NCAI until it is withdrawn or modified by subsequent resolution.

CERTIFICATION

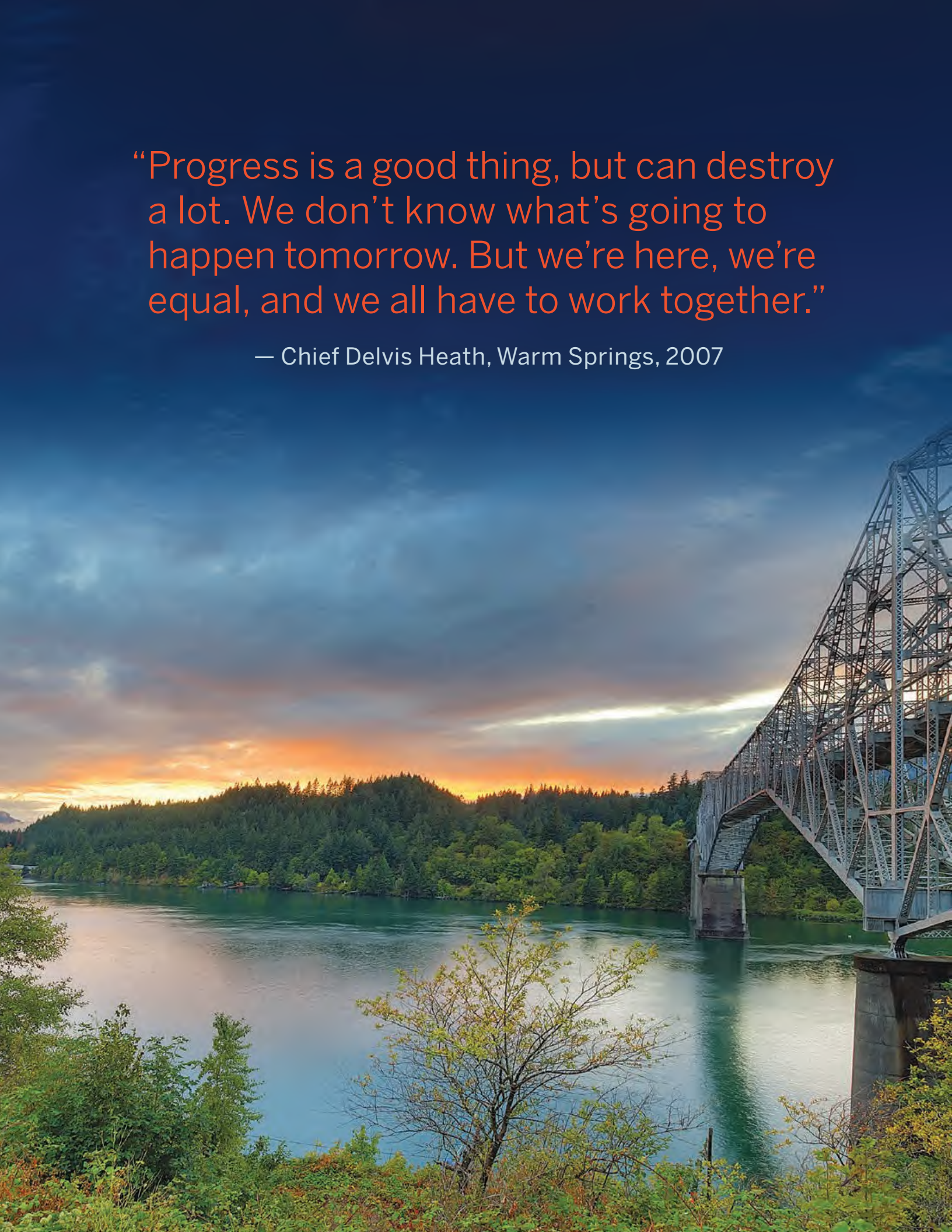
The foregoing resolution was adopted by the General Assembly at the 2021 Mid Year Conference of the National Congress of American Indians, held June 20, 2021 - June 24, 2021, with a quorum present.

Fawn Sharp, President

ATTEST:

Juana Majel Dixon

Juana Majel Dixon, Recording Secretary



"Progress is a good thing, but can destroy a lot. We don't know what's going to happen tomorrow. But we're here, we're equal, and we all have to work together."

— Chief Delvis Heath, Warm Springs, 2007

APPENDIX C:

Healthy and Harvestable Fish Population and Columbia River Hydroelectric System Configuration and Operations

Federal Fish and Wildlife Obligations Under the Northwest Power Act

When passing the Northwest Power Act in 1980, Congress acknowledged that the survival of the Basin's salmon is substantially dependent on the environmental conditions resulting from hydro system operations in the Columbia Basin.[154] The federal and non-federal hydro projects in the Basin have continually adapted their configuration and operations to improve the survival of affected fish and wildlife populations.

In the mid-1980s, the Northwest Power and Conservation Council made policy decisions on what share of the adult return fish losses were the responsibility of the hydroelectric system, concluding dams were responsible for reduced returns of five to eleven million of the fish, noting the impact estimate did "not take into account the accumulation of hydropower-related losses of salmon and steelhead year by years since hydropower development started. Such cumulative losses would be far greater than 5 to 11 million adult fish."[155] The Council also set an interim goal for the Fish and Wildlife Program of "doubling the runs...to a run size of about 5 million adult fish." The tribes viewed the Program's 1987 doubling goal as a compromise that would allow BPA to focus on an achievable interim goal and leave BPA's ultimate responsibility to a future decision process.

Some refinements to the Fish and Wildlife Program's goal have been made over the years, but no dramatic changes have been adopted that would reduce overall commitments. The most recent changes occurred in 2020 FWP Addendum with the adoption of Columbia Basin Partnership[156] (CBP) Phase II Report abundance goals as Biological Objectives/Targets. The CBP goals are population specific for 27 stocks of

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[154] 16 U.S.C. 839(6). It is generally accepted that the Basin's hydropower system has been "a major factor in the decline of some salmon and steelhead runs to a point of near extinction." 126 Cong.Rec. H10687 (1980) (letter from Comptroller General). The U.S. General Accounting Office ("GAO") described the impact of the hydropower system on anadromous fish in its September 4, 1979, report to Representative John D. Dingell, Chairman of the House Subcommittee on Energy and Power, as follows:

> Smolts surviving passage through the turbines of one dam enter the large, slow-moving reservoir of water formed by the next dam. The river no longer has the strong, swift current needed to carry the smolts rapidly downstream and out to sea. It now takes young fish more than twice as long to migrate downstream as it did before the dams were built. The slower the downstream migration, the more smolts are lost to predators. Others lose the desire to migrate and become permanent residents of the river, further reducing the breeding stock that finally reaches the ocean. It is the cumulative effect of hydro facilities which is so destructive. Each facility poses a separate and sometimes different set of problems for migrating smolts, and each contributes to a cumulative deterioration of the downstream migration. Depending on flows, juvenile losses from all causes average an estimated 15 to 20 percent at each main-stem dam and reservoir complex. Mortalities as high as 30 percent per project have been recorded under particularly adverse conditions.

[155] See 1987 Columbia River Basin Fish and Wildlife Program, page 39.

[156] NOAA Fisheries and its Marine Fisheries Advisory Committee (MAFAC) convened the Columbia Basin Partnership Task Force from 2017 through 2020 to bring together diverse representatives from across the Columbia Basin to establish a common vision and goals for salmon and steelhead.

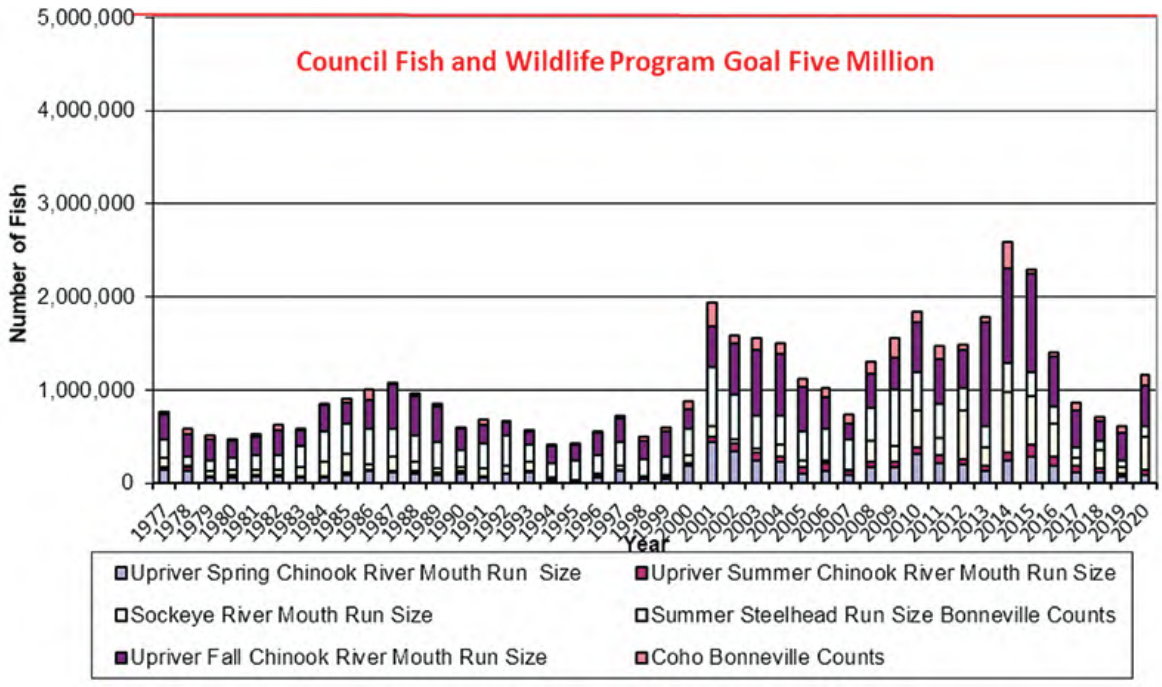
salmon and steelhead, with focus on natural origin fish. Low, medium, and high range goals are provided for specific populations and then adjusted and aggregated to larger spatial scales, including passage at Lower Granite and Bonneville dams.

While "Increas[ing] total adult salmon and steelhead runs of Columbia River origin to a 10-year rolling average of five million annually by 2025, in a manner that emphasizes increases in the abundance of the populations that originate above Bonneville Dam" remains as the FWP primary abundance goal (NPCC 2020), achieving run sizes at or above the CBP high range (healthy and harvestable) levels must be achieved with urgency.

The ultimate goal for the Federal government should be to address the requirements of the Endangered Species Act, the Northwest Power Act, and the Treaties, Executive Orders, and other commitments made to Indian tribes in the Columbia Basin. In the case of salmon and steelhead, the tribes seek to reach the dual goals of recovery and delisting of species listed under provisions of the ESA ***and*** the restoration of salmon populations to health and harvestable levels that support sustainable harvest sufficient to allow for a meaningful exercise of tribal fishing rights.

Reductions in salmon and steelhead abundance, productivity, and distribution was anticipated from the construction and operation of the CRS hydro-electric dams. Hatchery programs (*e.g.*, Lower Snake River Compensation Program, Mitchell Act and other actions) were established (congressionally authorized in many cases and others under the Northwest Power Act's Fish and Wildlife Program) to mitigate for direct and indirect the impacts hydro-electric dam construction and operations. In addition, FWP includes off-site mitigation to improve habitat, reduce predation, and supports adaptive management of dam operations. While these

FIGURE 22. Upriver Salmon and Steelhead Run Sizes



mitigation efforts have reduced overall impacts, they have failed overcome the impacts of the dams; actual adult salmon and steelhead returns remain well below the established goals.

FIGURE 22 shows the salmon and steelhead run sizes above Bonneville Dam from 1977 to 2017 compared to the Council Fish and Wildlife Program Interim goal of 5 million salmon and steelhead returning annually to the Columbia Basin. The Federal agencies responsible for implementing the Columbia Basin Fish and Wildlife Program (BPA, the Corps of Engineers, the Bureau of Reclamation, and the Federal Energy Regulatory Commission) are a long way from achieving the goals set in the Fish and Wildlife Program.

Current Biological Conditions

The Columbia Basin is home to one of the richest arrays of salmon and steelhead in the world, and this wealth of anadromous species holds great ecological, cultural, spiritual, and economic value. Salmon and steelhead are cornerstones in Columbia River Basin ecology and tribal culture, with historical returns estimated at 10–16 million fish, annually[157]; contemporary abundance of anadromous fish is only small fraction of their former run sizes (CBP Phase II, Thurow 2020). These resources are at risk, most stocks are currently listed under the Endangered Species Act (ESA) or have been extirpated.

- Twelve salmon and steelhead populations in the Columbia Basin are listed as either threatened or endangered under the Endangered Species Act.
- The total abundance of salmon and steelhead in the Columbia River is at or near the abundance when the first ESA listings were registered in the mid-1990s.

Various quantitative expressions describe the productivity of healthy salmon populations in tribal, state, and federal publications and regulatory documents. Once such metric—typically known as replacement—describes a growth rate of 1.0, where one adult in the parent generation produces one adult in the generation of offspring. Currently, many populations of salmon and steelhead in the Columbia Basin are below replacement, and their population growth rates need improvement just to reach this measure. Moreover, some positive degree of productivity or population growth rate sufficient to buffer the population against stochastic events, such as droughts and heat waves, is necessary for the health of the species. With relatively functional freshwater spawning and rearing habitat (productivity ~100 smolts per female), out-of-basin survival (smolt-to-adult return rates; SAR) of 2–6%, averaging 4% are needed to reach adult return goals. Recent Snake Basin spring/summer Chinook salmon SARs have been at or below 1% and freshwater productivity is often below 100 smolts per female. As a result, abundance of wild origin spring/summer adults in nearly half of the Snake River basin's populations are at or below a Quasi-Extinction Threshold of 50 wild-origin spawners.

To naturally persist, a population must be able to reproduce and survive at a certain rate to sustain itself. The survival of a species requires parents producing sufficient numbers of offspring to sustain the reproductive potential of the population as a whole. In addition to reproductive rates, the overall size of the population is important to its long-term health. A large salmon population may be able to persist through periods of low productivity. On the other hand, smaller populations are not as resilient. The combination of population size and productivity are used to define degrees of risk.

[157] https://www.nwcouncil.org/reports/columbia-river-history/salmonandsteelhead/

Other characteristics used to measure species viability include diversity and distribution.

Wide-swaths of Columbia basin habitat, once supporting anadromous salmon and steelhead, currently lacks salmon and steelhead production due to dams that blocked fish passage. Chief Joseph dam on the Columbia River[158], Dworshak Dam on the North Fork Clearwater River, Hells Canyon Dam on the Snake River, and Wallowa Lake Dam on the Wallow River preclude anadromous fish from reaching historically used spawning and rearing habitats. In addition to their lack of fish passage, operation of these dams alters fish habit in areas down-stream due to their impacts on water quality and quantity (timing and volume).

The remaining extant Upper Columbia and Snake River salmon and steelhead populations are in dire condition, with mid-Columbia stocks closer to medium range goals.

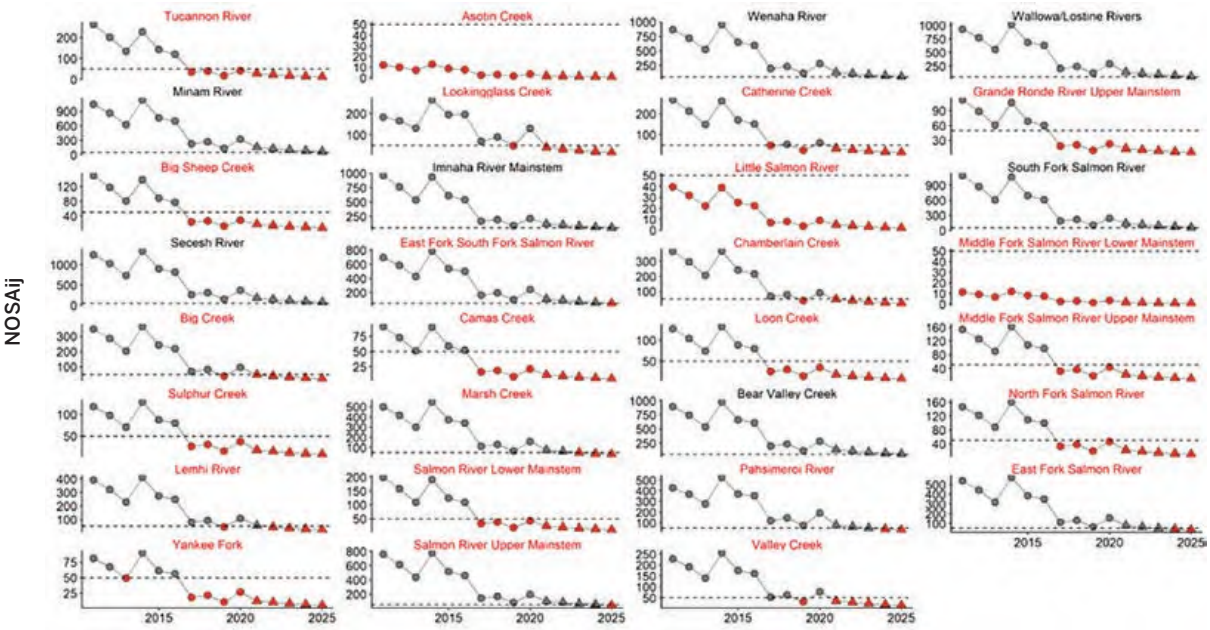
- Three stocks triggered NOAA's 2014 BiOp early warning and significant decline indicators: Upper Columbia Spring Chinook, Upper Columbia Steelhead, and Snake River Steelhead.
- NOAA's life cycle modelling of future climate scenarios for Snake River spring/summer Chinook salmon populations indicates that the median abundance of spring and summer-run Chinook salmon populations could further decline substantially in the next two to three decades, which would threaten to extirpate a large number of small populations.
- Spring/summer Chinook salmon in the Snake Basin are in trouble. Over the last four years, natural origin adult abundance in 44% of the ESA listed populations has been at or below the Quasi-Extinction Threshold (QET) of wild-origin 50 fish[159]. If adult salmon abundance continues to decline at a similar rate as the last 10-years (19% per year), nearly 80% of the populations may drop below 50 natural-origin spawners by 2025 and some populations will likely become extirpated in the near future (NPT 2021). **(FIGURE 23)**
- The number of adult steelhead returning to the Snake Basin dramatically dropped from a 40 year high of over 45,000 natural origin fish in 2015 to 15,000 or less estimated annually at Lower Granite Dam since 2017. Over the last four years, three (19%) of the Snake Basin steelhead populations have been at or below the Quasi-Extinction Threshold of 50 natural-origin fish. If adult steelhead abundance continues to decline at a similar rate as the last 10 years (18% per year), nearly half (44%) of the populations may drop below 50 natural-origin spawners by 2025; populations with B-run life history characteristics appear to be declining at a highest rate (NPT 2021). (**FIGURE 24**)
- Snake River sockeye salmon are fully dependent upon conservation hatchery (captive broodstock and supplementation) support.

[158] Chief Joseph and Hells Canyon dams are the first dams encountered by upstream migrating adults that lacking fish passage, subsequent upstream dams also lack passage and block access to historically used habitat.

[159] Quasi-Extinction is defined as 1) a population that is uncertain to persist; 2) there are not enough parents to successfully reproduce and perpetuate the population; and 3) the probability of recovery is low without substantial intervention.

FIGURE 23. Spring–Summer Chinook Salmon

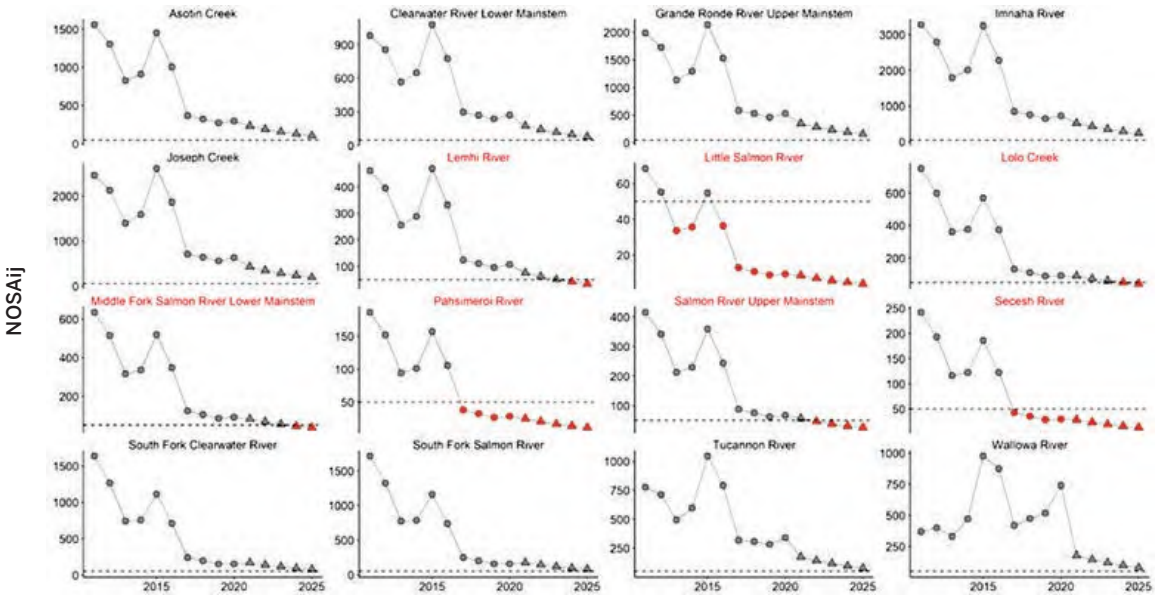
Future predictions of natural-origin spawner abundance (NOSAij) for Snake River Basin show 24 populations (77%) will start to drop below the quasi-extinction threshold (QET: dashed line; 50 spawners) within the next 5 years.



Source: Data through 2019 provided from Coordinated Assessments on 3/22/2021; 2020 data provided through personal communication with ODFW, IDFG and NPT.

FIGURE 24. Summer Steelhead

Future predictions of natural-origin spawner abundance (NOSAij) for Snake River Basin show 7 populations (44%) will start to drop below the quasi-extinction threshold (QET: dashed line; 50 spawners) within the next 5 years.



Source: Data through 2019 provided from Coordinated Assessments on 3/22/2021; 2020 data provided through personal communication with ODFW, IDFG and NPT.

Appendix C

- Snake River Fall Chinook salmon are limited to a single population that is actively supplemented. This population has rebounded from less than 100 natural origin returns in 1990 to a 10-year geometric mean now exceeding 9,000.
- Snake River coho salmon were extirpated from the Snake basin in 1986, but have been reintroduced, with returning adults now occurring from hatchery releases.
- Upper Columbia Spring Chinook have recently experienced the lowest abundance levels in their last 15 years. Their abundance and productivity remain well below the viable thresholds called for in the Upper Columbia Recovery Plan for all three populations (Methow, Entiat and Wenatchee) and these populations remain at high risk.[160]Upper Columbia steelhead experienced their lowest abundance level in the past ten years in 2018. Natural origin abundance and productivity remain well below viability thresholds for three out of the four populations (Okanagon, Methow, Entiat, and Wenatchee (improving)); however, the overall DPS status remains at high risk.[161]
- Mid-Columbia Steelhead started their precipitous declines in 2017 which have persisted through 2021. Yakima River MPG numbers declined to ~1,000 fish, numbers that haven't been observed since the time of ESA listing in 1999. There have been improvements in the viability ratings for some of the component populations of Mid-Columbia steelhead lower in the basin, but the DPS is not currently meeting the viability criteria described in the Middle Columbia River Steelhead Recovery Plan and the risk status has remained unchanged for the past three reviews.[162]
- Mid-Columbia spring chinook salmon, Mid-Columbia summer Chinook salmon, and Mid-Columbia fall Chinook salmon ESU status will be released shortly in the 2021 NOAA 5-year status assessment.

Warming River Water Temperatures

High summer water temperatures in the Columbia River System are known to have detrimental outcomes on fish survival and recovery. For example, in the summer of 2015, low flow conditions combined with lethally high temperatures in the Columbia and Snake River killed all but 1 percent of the Snake River sockeye salmon run. Lower river passage survival relative to temperature can be seen in **FIGURE 25** from a NOAA report on the 2015 sockeye passage season:[163]

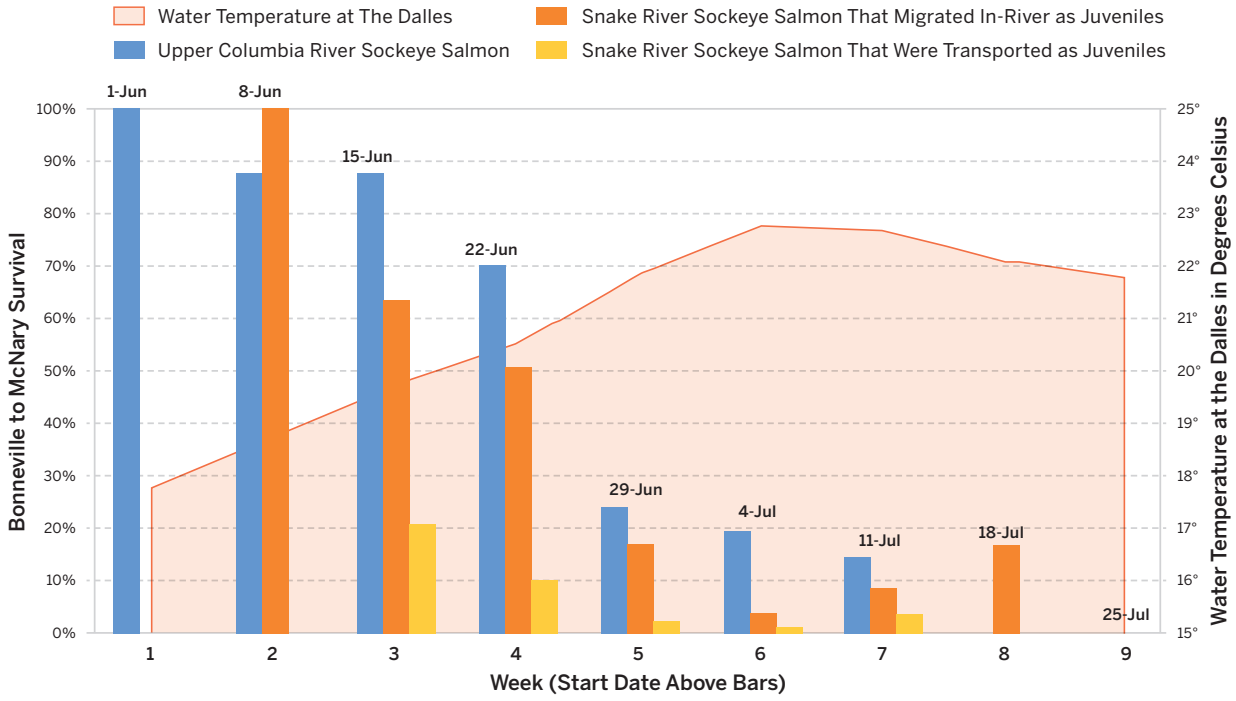
[160] NOAA Fisheries, 2016 5-Year Review: Summary & Evaluation of Upper Columbia River Steelhead Upper Columbia River Spring-run Chinook Salmon.

[161] *Id.*

[162] NOAA Fisheries, 2016 5–Year Review: Summary & Evaluation of Middle Columbia River Steelhead.

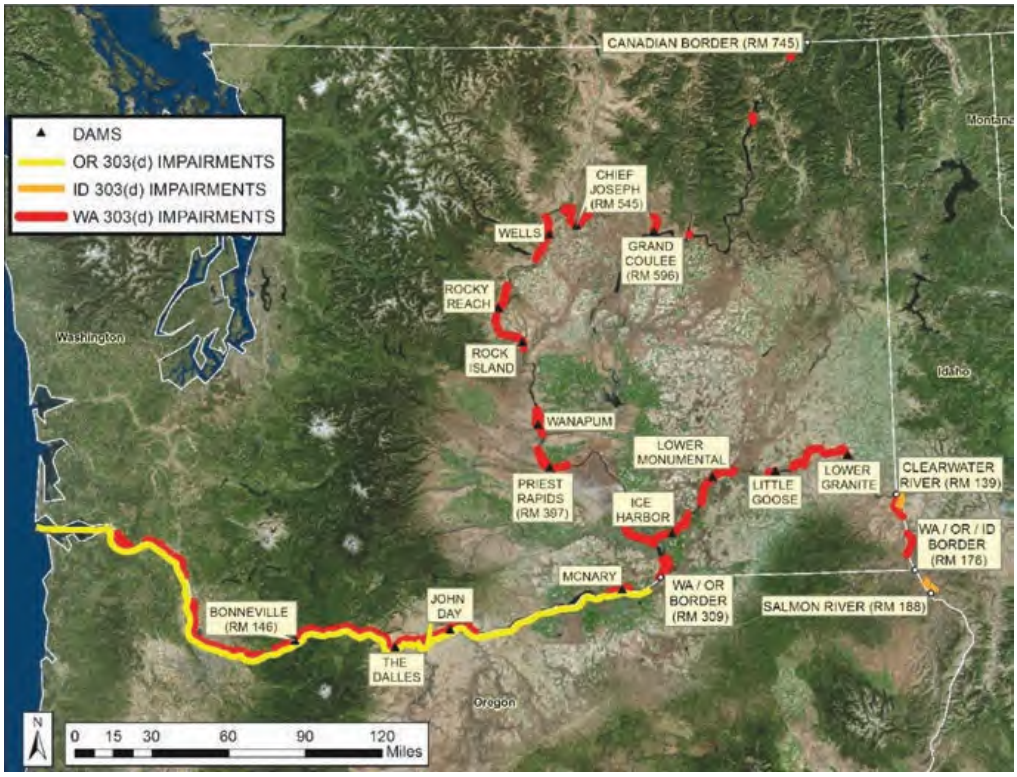
[163] NOAA Fisheries, 2015 Adult Sockeye Salmon Passage Report, Sept. 2016, available at https://archive.fisheries.noaa.gov/wcr/publications/hydropower/fcrps/2015_adult_sockeye_salmon_passage_report.pdf.

FIGURE 25. Weekly Adult Sockeye Survival Estimates from Bonneville to McNary Dam in 2015



Source: PITAGIS data and Columbia River DART

FIGURE 26. Map of Current Clean Water Act Impairments for Temperature in the Columbia and Lower Snake Rivers



Appendix C

Losses such as those experienced in 2015 will only be intensified by a warming climate. An analysis of temperature conditions in the Columbia and Lower Snake Rivers can be found in EPA's Total Maximum Daily Load (TMDL) for Temperature on the Columbia and Lower Snake Rivers (draft May 2020, final expected 2021). The geographic scope of the TMDL includes waters within the mainstem of the Columbia River from the Canadian border to the Pacific Ocean and within the mainstem of the Snake River in Washington from the confluence with the Clearwater River at the Idaho border to its confluence with the Columbia River. **FIGURE 26** shows current Clean Water Act impairments for temperature in the Columbia and Lower Snake Rivers.

The TMDL report is a detailed analysis of the sources of thermal impairment on the Columbia and Lower Snake rivers. The analysis points to the Federal Columbia River Power System as a primary source of thermal impairments. The TMDL makes clear that some significant changes to dam operations and alternative management of reservoir releases will be necessary to achieve temperature reductions and to limit the magnitude of impairments.

Columbia River Hydroelectric System Configuration and Operation

Multiple factors have contributed to these low returns, including especially construction and operation of hydro-electric dams. Protecting, restoring, and effectively managing these valuable species is one of the region's greatest responsibilities. Science on the status (abundance, productivity, and mortality factors) clearly shows a diversity of actions are needed, including breaching, to reach and maintain Snake basin fish populations at healthy and harvestable levels—especially in the light of climate change.

Given the imperiled condition of fish stocks impacted by Federal Columbia River Power System (FCRPS) dams and other important non-federal dams in the Basin, it is prudent to plan for variations in hydro configuration and operation going forward. The following subsections provide more detail on fish-related goals, fish population status, and hydro-project configuration and operational impacts to fish and wildlife. First and foremost, all hydro system operations for both flood control and power generation should consider how those operations may impact salmon survival and how they may be implemented to resemble a more normative river hydrograph.

Hydro-system configuration and operations must be compatible with and support achieving salmon and steelhead adult return goals in the near future, and in manner that is sustainable. Priority hydro-system actions should generally target high spill (non-powerhouse passage of juveniles), expanded spill periods (surface passage route option for all life stages and migration periods), reduced water travel times (elimination of zero flow periods and

minimum operation pool elevation), maintenance of functional habitats (no load shaping at Dworshak Dam), flow augmentation (cold water, stable flow periods, spring peak shaping), and juvenile transportation refinement (total dissolved gas management). These types of actions result in reduced powerhouse encounter rates (PITPH), accelerated fish travel times, and opportunity for year-round surface passage by all life-history behaviors (diversity).

Several actions could begin to rebuild habitat quantity and quality of the mainstem and tributaries: a) Reregulate flows to restore the spring high-water peak and revitalize the mosaic of habitats in alluvial riverine reaches; b) Reregulate flows to stabilize daily fluctuations in flow (caused by the practice of "power peaking" and lowering flows to store power from renewable resources) to allow food web development in shallow water habitats and reduce juvenile mortalities via stranding; c) Provide incentives for watershed planning that emphasize riparian and upland land use activities that support natural interactions between land and water, and insist on empirical evaluation of effectiveness of management practices; d) Couple seasonality of flow with spill rates over the dams that efficiently bypasses juveniles and adults around mainstem dams and behaviorally cue (rather than physically flush) the juveniles through the mainstem; and e) Restore mainstem habitats to more natural conditions which will reduce predation rates on migrating juvenile salmon.

First and foremost, all hydro system operations for both flood control and power generation should consider how those operations may impact salmon survival and how they may be implemented to resemble a more normative river hydrograph.

1. RUN OF RIVER DAM OPERATIONS

Spill Operations to Aid Juvenile and Adult Salmon Passage

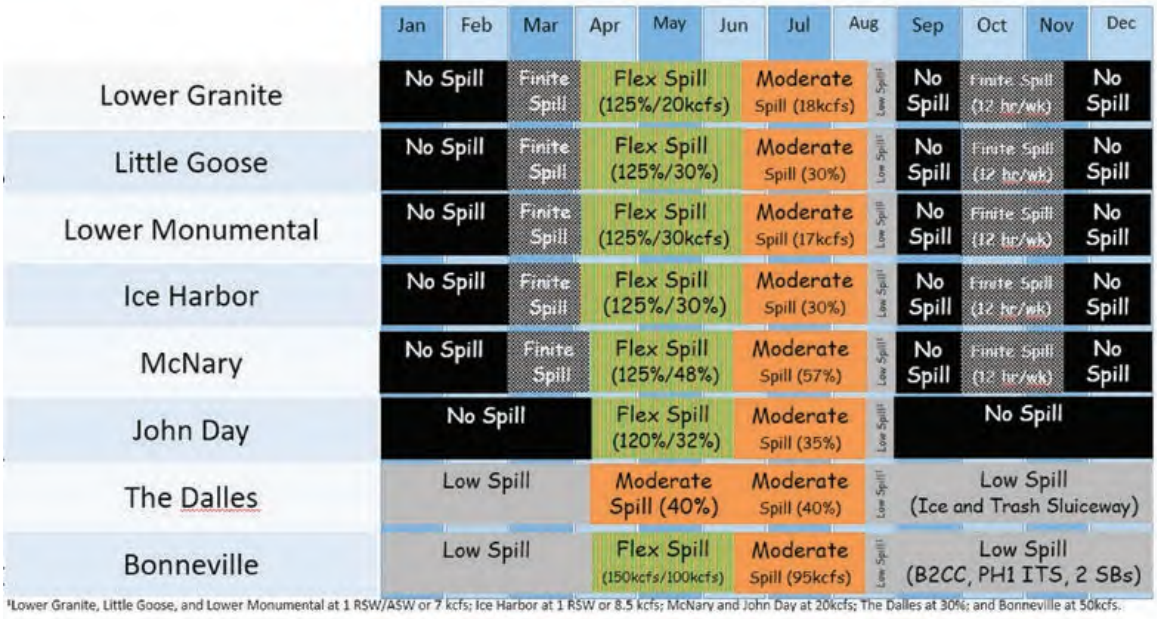
Specific spill operations with sizable interim benefits for fish and likely compatible with long-term healthy and harvestable fish returns are detailed in **TABLE 8** and **FIGURE 27**.

TABLE 8. High level summary of current and proposed spill operations at lower Columbia and Snake River projects, by season. See also **FIGURE 27** for project specific details.

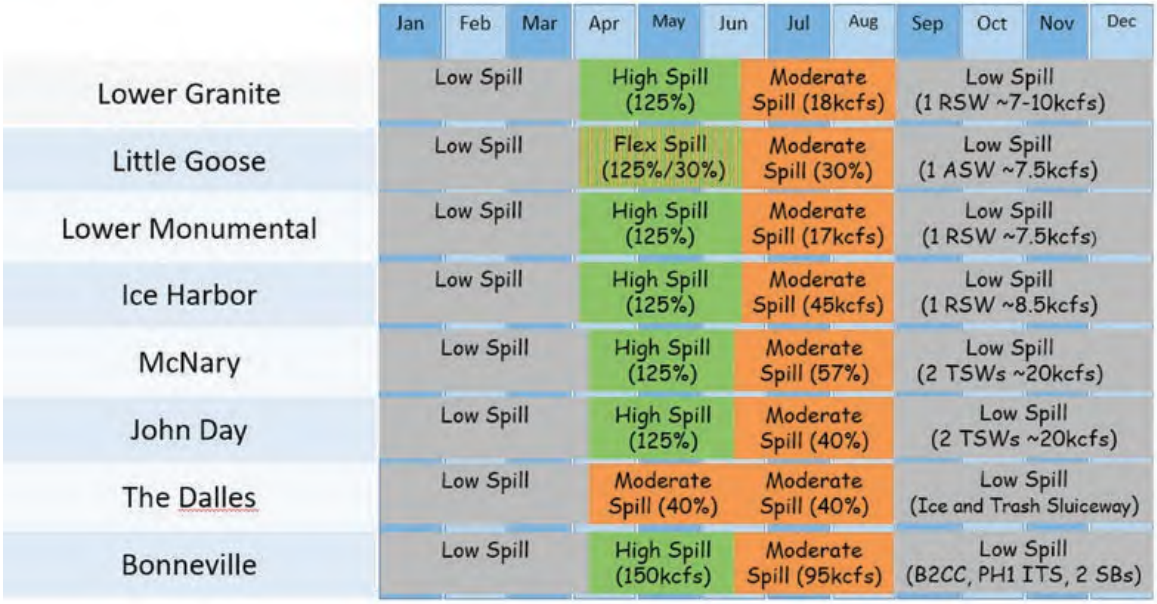
Season	Current 2020 Biological Opinion	Interim Maximized Spill	Long-Term Breached Lower Snake
Winter (January to February)	No Spill	Low Spill	Low Spill
Early Spring (March)	Finite Spill (12 hours per week)	Low Spill	Low Spill
Spring (April to mid-June)	Flex Spill	High Spill	High Spill
Summer (mid-June to mid-August)	Moderate Spill	Moderate Spill	Moderate Spill
Late Summer (mid to late August)	Low Spill	Moderate Spill	Moderate Spill
Fall (September to December)	Finite Spill (12 hours per week)	Low Spill	Low Spill

FIGURE 27. Current and Proposed Project Specific Spill Operations at Lower Columbia and Snake River Dams.

Panel (A): Current operations under the 2020 Columbia River System (CRS) Biological Opinion.

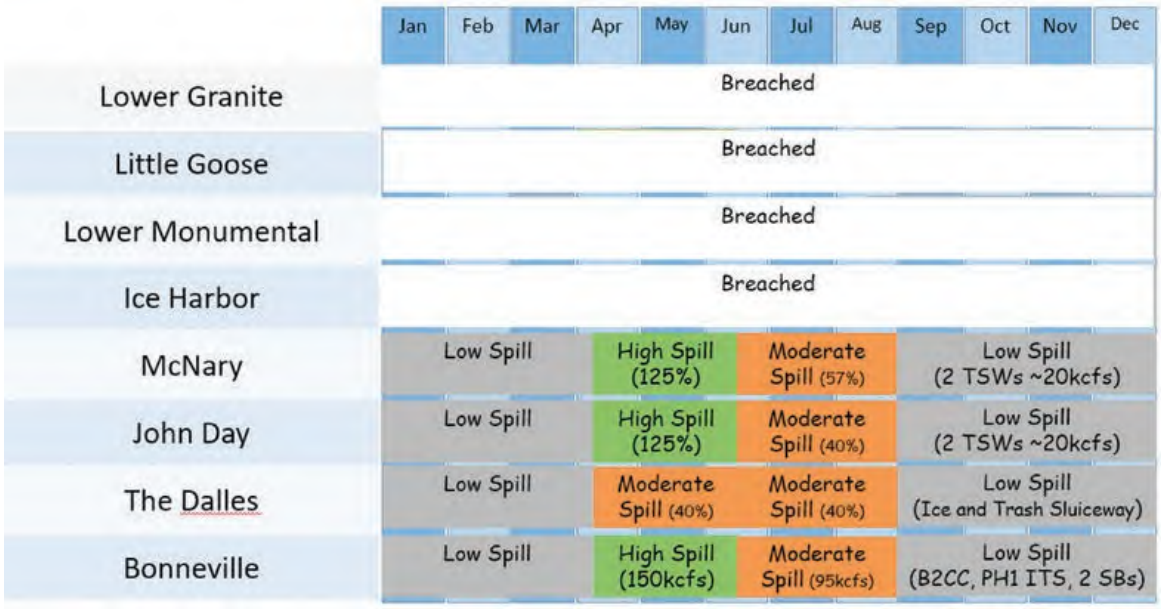


Panel (B): Maximum spill operations proposed for interim operations under the Columbia River Initiative.



TSW = Temporary Spillway Weir **RSW** = Removable Spillway Weir
PH1 ITS = Ice and Trash Sluiceway. **B2CC** = Corner Collector **SB** = Traditional Spillbay

Panel (C): Lower Snake River breach and lower Columbia River max spill proposed for long-term operations under the Columbia River Initiative.



TSW = Temporary Spillway Weir **RSW** = Removable Spillway Weir
PH1 ITS = Ice and Trash Sluiceway. **B2CC** = Corner Collector **SB** = Traditional Spillbay

Operate at Minimum Operating Pool

Ensure that projects are operated at Minimum Operating Pool (MOP) throughout the migration season to reduce pool volumes and decrease water particle travel time which aids in decreasing migration time. A lower pool elevation creates more flow and more closely resembles a river environment. Existing reservoir (pool) levels are set to MOP in the Snake but not at all the Lower Columbia projects. All Lower Columbia Projects should be restricted to MOP. There are current limitations to MOP in both the Snake and Columbia rivers due to other designated purposes of the hydro system.

In the Snake River, the Federal Navigation Channel must maintain a required depth at all flows; therefore, an elevated pool above MOP is necessary because of sedimentation. Until the channel is dredged, or barges are required to lighten load requirements, MOP will not be implementable during periods of low flow. This risk shifting to salmon is unacceptable.

In the Lower Columbia, John Day (the largest reservoir) is operated to only MIP (minimum Irrigation Pool) several feet higher than MOP. This is due to irrigation withdrawals not being deep enough. If the irrigation withdrawal capabilities are extended, then MOP could be achieved. Other restrictions at John Day are higher pool elevations to aid in predation management. At higher pool elevations avian predators are unable to nest on Blalock Islands. However, dissuasion could be used in place of elevating the pool to achieve the same result, allowing a return to lower pool elevations.

Lower pool elevations would also help reduce sedimentation plumes that form at the mouths of the tributaries creating shallow water habitat and reducing cold water refugees that migrants can take advantage of.

Allow for Increased Total Dissolved Gas Waivers Year-Round

Historically, total dissolved gas (TDG) limit waivers, as set by the states of Washington and Oregon, have allowed spring and summer spill operations in aid of fish passage to exceed the statewide 110% TDG limit and reach up to 115% TDG in the forebay of each dam and 120% TDG in each tailrace. To support the Flex Spill Operations Agreement, the states removed the forebay TDG limit for spring 2019 operations, allowing operations to be curtailed only by the 120% TDG tailrace limit.[164] For 2020, the states raised the tailrace limits to 125% TDG for the spring passage season, allowing for even more spill at each dam.[165] These increases in TDG waivers should be enacted year-round and allowed for purposes other than fish passage to allow for more flexibility in water management and flood control operations. Current TDG waivers can hamstring operations and cause projects to be too cautious based on early seasonal forecast, leading to less water augmentation for the spring and summer time periods to the determent of juvenile outmigrants.

Reduce Power Peaking

Reduce power peaking at passage dams during emergence and migration periods to reduce stranding of fry and smolts. Power peaking can also cause temporary disturbance or oscillation in the water level that can confuse downstream and upstream migrants and increase travel time. This operation is currently implemented below Priest Rapids Dam with tremendous success for the Hanford Reach Fall chinook population.

Strictly Limit Periods Of Zero Flow

Periods of very low or zero flow are currently allowed and are not based on biological triggers, such as the number of fish present in the river. Zero flows should only be allowed when biological triggers have been met to ensure there is little to no risk to migrants. Constraints need to be integrated into the power operations to maintain minimum levels of flow when fish are present in the system.

2. RESERVOIR OPERATIONS AT STORAGE DAMS

Implement Modified Flood Control During Years With Lower Seasonal Snowpack

Modeling has shown that modified flood control is important during low snow years when flood control is not as much an issue, but spring/summer flows are at risk from diminished runoff. During years of high snowpack, there is generally sufficient water for spring/summer migrations, but a higher flood risk that must be controlled by releasing more water during the winter. Modifying flows in low flow years allows more water to be shifted into the spring and summer and supports juvenile migration with shorter downstream travel times. Recent increases in gas waivers allows for more water to be spilled without causing Total Dissolved Gas (TDG) concerns. This increased capability should be considered when setting flood control targets. Increased flows during spring migration coupled with increases in spill can help to reduce powerhouse encounters for migrating juveniles. Smolt to adult return rates (SAR's) are higher when the number of powerhouses that juveniles encounter is decreased.

[164] For a more detailed explanation, see the Corps of Engineers' Fish Operation Plan for 2019 at 2, available at http://pweb.crohms.org/tmt/documents/fpp/2019/final/FPP19_AppE.pdf.

[165] See http://pweb.crohms.org/tmt/documents/fpp/2020/final/FPP20_AppE_FOP.pdf for more details.

More In-Depth Measures, Such as Altered Flood Control, May Be Needed Across the System.

Altered Flood Control (AFC), where all rule-curves for key Federal storage dams (*e.g.*, GCL, HGH, LIB, DWR), BC dams (*e.g.*, MCD, DCD, ARD), and one FERC dam (BRN) across all water year classes should be considered. The effective AFC operation is controlled mainstem river flood pulsing. There have been some peer-reviewed published studies showing the ecological benefit of controlled flood pulsing. The result is a more natural or "normative" hydrograph that is more in tune with the salmon's life cycle and accommodates the coming changes to basin hydrology due to future climate change impacts. Such a change in lower Columbia River flood risk exceedance may slightly raise the risk while still providing reasonable flood control protection.

Flood Risk Assessment for the Lower Columbia River

The Corps of Engineers has yet to perform a badly needed flood risk assessment for the lower Columbia River; the last assessment was done in the 1970s. So, the question of what level of flood risk management should accommodate salmon restoration is unanswered. The Corps' trend in flood control operations since the 1980s is for an increasing diminished peaking hydrograph. Among other things, this reduces volumes of water needed for the Columbia River estuary plume. Any change to the Corps' flood risk management operations will need Corps buy-in and cooperation so that they are still meeting their congressional mandates. Various alternative flood control operations have been modeled with the Council's GENESYS Hydro-model that show the absolute/differential values of mainstem river flow and project/FCRPS generation relative to a fixed standard, in this case, the 2000 Biological Opinion FCRPS operations (Dittmer 2006). Those previous analysis can be made available upon request.

3. OTHER HYDRO-ACTIONS TO IMPROVE SALMONID SURVIVAL

Grand Coulee Drum Gate Repairs

Implement structural modifications at Grand Coulee to allow drum gate maintenance to occur regardless of flow year and reduce the required draft to perform the work.

This draft can have large impacts in early spring flows or put the region in the position to have to choose between spring and summer flows since it may preclude providing adequate flow during both time periods.

Dworshak Operations

Operate Dworshak Dam on the North Fork Clearwater River to better mimic the spring freshet. Current flood control drafts occur early in the winter when there is little information on what type of flow year will be realized. This can easily lead to excessive deep drafts that make it challenging to achieve refill, let alone provide spring flow augmentation.

Install Additional Turbines at Key Projects

Install additional turbines at projects such as Libby and Dworshak to allow for more flexibility in moving water and reduce the risk of over drafting due to project limitations. This would allow the operators more time before selecting target elevations. This would allow for more climatological data to be considered to ensure that optimum reservoir operations are realized.

Gregg M. Erickson / CC BY 3.0

4. IMPLEMENT CLIMATE MITIGATION MEASURERS

- Implement purchase agreements or utilize other means to reduce water withdrawals and leave more water in tributary rivers, especially in the late spring and summer months to aid both juvenile and adult migrants. More water left in the rivers will help to decrease travel time and buffer temperature increases. Additionally, under future climate scenario, flow for generation in the summer will be more valuable.
- Address thermal impacts associated with hydropower operations by implementation of a temperature reduction plan for the Columbia and Snake Rivers in accordance with the EPA temperature TMDL.
- Develop a long- and/or short-term sediment budget model throughout the Columbia River Basin with specific focus on the Cold-Water Refuges (CWR) along the river. Such a model can aid in hydroplaning of the river locations with objectives of optimizing salmon survival.

5. HYDRO OPERATIONS: MID-COLUMBIA

Juvenile survival through the hydro system is lower for yearling chinook and steelhead in the Mid-Columbia, relative to their Snake River counter parts (2020 CSS). Also, PITPH, which is the relative proportion of fish passing dams via their powerhouses, is higher for steelhead originating from the Entiat-Methow rivers than from elsewhere in the Basin. This is important because CSS modeling has demonstrated that each additional powerhouse encounter by wild steelhead groups from the Snake River, Entiat and Methow rivers, Yakima River and John Day Rivers may reduce SARs by 21%. Similarly, each additional day of water transit time could reduce SARs by 14%.

Improved ecosystem-based functions, like additional fish flows during the spring freshet can decrease transit times through the system while reducing the number of powerhouse encounters by out-migrating smolts. Columbia River Treaty negotiations are therefore critical to the recovery Mid-Columbia salmon and steelhead stocks.

Improvements in lifecycle models and increased PIT tag detection in the mid-Columbia can work hand in hand to identify and target problems at a given life stage or problems at a more specific location on the Columbia River. For example, adding a spillway PIT tag detection system at the Wanapum project in Grant County would provide two valuable purposes. First, it would provide new insights into the survival of out-migrating juvenile smolts from Rocky Reach Dam to Wanapum Dam and from Wanapum Dam to McNary Dam. Second, it would improve the detection probabilities of smolts throughout the Mid and Lower Columbia River. While improvements in PIT detection can provide a better window to juvenile survival in the

mainstem, improvements in life cycle models can provide additional clues to fish survival/mortality in the mainstem and tributaries.

6. FISH PASSAGE IMPROVEMENTS AND MAINTENANCE AT FEDERAL COLUMBIA AND SNAKE RIVER DAMS

The following description of needed routine fish passage improvements and maintenance was compiled by CRITFC staff to help better understand the budgetary needs and short comings for both the US Army Corps of Engineers (Corps or Corps of Engineers) Columbia River Fish Mitigation budget (CRFM) and the Corps Operational and Maintenance budget (O&M). The compiled costs anticipate implementation and expenditure over an 8-year time frame so projects can be both one-time cost as well as a reoccurring cost. The majority of the items in the budget are ones that the Corps of Engineers has highlighted at the regional System Configuration meetings (SCT) and include the unfunded items from the O&M budget that were presented at the Fish Passage Operations and Maintenance regional meetings. The other items and projects are identified in the Proposed Action from the Action Agencies as well the NOAA's recent Hydro Biological Opinion. Additional items are needs that have been identified by staff working with regional sovereigns and stake holders.

Fish ladder repairs and improvements

Fish ladders are necessary to pass adult salmon upstream past the hydroelectric dams on the Lower Columbia and Snake Rivers. The ladder technology at most of the dams is 50 to 80 years old and in need of repairs, some extensive, to keep the ladders in service. Diffusers and Auxiliary Water Supply systems (AWS) are key components to supplying water throughout the fish ladder. A ladder failure during the peak of salmon runs would be disastrous since most dams only have 1 or 2 ladders. If a ladder fails, there are no other adequate means for adult salmon to get past the dam and to reach their spawning gravels and a whole year class of salmon could be lost. The water supplied to the ladders for operation are provided either from fish turbines or pumps. Many of these pumps and turbines are aging and have failed. John Day and McNary dams for example are operating with less than the needed number of pumps. If one of the current pumps fails, the ladders would not be able to operate and would require most of the entrances to be closed. This would require any adult salmon trying to pass the dam to find only a small entrance across the entire dam with little or no attraction water.

Climate change will increase not just absolute river temperatures but the length of time the river is at temperatures that stress salmon and impacts their survival. To help combat this, cooling water structures are needed at several of the adult ladders to ensure adult salmon continue to migrate and thermal barriers are not created at the dams.

The total cost of ladder repairs and improvements identified by tribal, federal, and state technical experts is $160.4M to be implemented over 8 years.

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Courtesy US Army Corps of Engineers

Spillway Repairs and Improvements

The spillways at the dams are critical passage routes for juvenile salmon as they migrate to the oceans. The spillways also provide an important means for moving water during high flow events to aid in flood control. Modifications to spillway have been ongoing for 20 years to improve the efficiency and safety of the route. However, at several of the projects, most notably Bonneville dam, erosion and safety concerns about the operation of the spillway have arisen starting in early 2000. At Bonneville dam, spill is limited to reduce the creation of hydraulic conditions to draw boulders into the stilling basin and cause additional erosion and damage that could take the spillway out of service. Modifications to the spillway such as notched spillway weirs that use less water could help reduce the cost of spill for salmon as outlined in the recent NOAA Biological Opinion where spill is now required during times of year where it previously was not provided.

The total cost of spillway repairs and improvements identified by tribal, federal, and state technical experts is $170.9M, to be implemented over 8 years.

Fish Screen and Juvenile Bypass System (JBS) Maintenance

The fish screens are part of Juvenile Bypass Systems (JBS) that provides juvenile salmon and lamprey an alternative passage route to that of turbines. The screens divert juveniles away from the turbines and then forces them up into a gate well where they are in turn passed through dewatering orifices and piped around the dam or to raceways where they are held for transportation. Current data indicates that while survival upon release is comparable to a spillway, there is reduction in long term fitness and thus lower survival for those that use many of the JBS systems on the Columbia and Snake rivers. It is important to note that there will be powerhouse operations during juvenile migration times and protection for migrants will be needed. While JBS's are not a perfect solution they provide a safer route than most turbines. The screens need annual maintenance and the current design for the extended screens were not intended for juvenile lamprey. Juvenile lamprey are found to get impinged on the extended screens and leads to mortality. Many of the JBS's are aging and need to be rebuilt and upgraded. Many of the JBS's were retrofitted to the dams and were built before there were guidelines and knowledge about what would be the best design for juvenile migrants that they would encounter.

The total cost of repairs and improvements to the Fish Screens and JBS's identified by tribal, federal, and state technical experts is $132.7M, to be implemented over 8 years.

Survival Studies (for Flex Spill Operations, Turbine Improvements and Monitoring)

Over the past 20 years project operations at the dams have changed as knowledge and litigation has progressed. Part of what drives these changes is knowledge gained through studies and monitoring. As new systems are put in place it is wise to study them to determine they are operating as intended and are providing the benefit that was expected since the science and knowledge for what is best for adult and juvenile salmon continues to improve. The flex spill operations that were implemented over the last three years are an example of operational changes that are quite different than what has been done previously. It is imperative that monitoring and evaluation studies are conducted to insure the planned benefits are being realized.

Most studies and monitoring are based on using information gained as juveniles pass the powerhouses at the dams. The flex spill program has the goal of reducing powerhouse passage and passing the majority of migrants through the spillway. The new spill program appears to be working with the majority of juvenile migrants going over the spillway, however there is not enough data being collected to get very accurate or precise reach survivals as well as other important information to help inform managers if this new spill program is producing benefits over past years operations. To aid in this, additional means to collect data need to be pursued and advanced. There has been success with new monitoring structures such as the Lower Granite Spillway Pit Tag detection system. However there have not been adequate funds to implement additional and other promising technology to help gather this critical information.

The total estimated cost of studies and improvements for monitoring identified by tribal, federal, and state technical experts is $50.5M.

Predator Management

The Corps has funded extensive avian predator management programs in the mainstem and estuary. These programs have been vital to improving survival of juvenile migrants. However, the Corps is proposing to reduce the level of effort aimed at predator management. At the same time, invasive fish species such as Northern pike, bass, and walleye, are increasing in numbers and consume large numbers of juvenile salmon and steelhead. For certain species such as steelhead, avian predation can make up over half to two thirds in some years of the total mortality of juvenile smolts as they travel from the Upper Columbia and Snake River to Bonneville dam.

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The Corps needs to increase funding for predator management and coordinate their predator management programs through a central forum to ensure that funding is targeting the worst offenders and that we are not merely switching the consumers rather than reducing the consumption of juvenile migrating fish. We are proposing $3.2M for monitoring and predator management programs and $8M for implementing predator management in the Columbia River. We strongly encourage close coordination between the Corps predator management programs and those funded through BPA and the mid-Columbia PUDs.

The total cost of predator management and predator deterrence structures identified tribal, federal and state technical experts is $31.2M, to be implemented over 8 years.

Sediment Management and Cold-Water Refuges

Sediment management has been an overlooked problem since the construction of the dams. Some dredging has occurred to assist with inland navigation but the accumulated sediments at tributary deltas and other areas within the reservoirs due to low flow in the mainstem continues to have a negative impact on salmon survival. The Zone 6 and the lower Columbia tributary mouths provide critical sources of cold water for salmon holding while on their migration route (adults upstream and for the late season juvenile downstream migrants). The tributary mouths are currently shallow, slow moving, and provide ideal conditions for warm-water piscivorous fish and avian predators that benefit from the shallow sand bar habitats with no habitat complexity. The tribes are proposing to implement sustainable actions which can result in restoration and conversion of key fish habitat in potential cold-water areas. These actions would include dredging tributary river mouths and reconfiguring habitat to support native vegetation, provide refugia for resting fish, and improve connectivity between cold water areas and the main river.

It is estimated that $500K/year will be needed for hydrographic assessments and monitoring and approximately $12M/year is needed for restoring these river mouths and creating and maintaining important cold-water refuges.

The total cost of Sediment Management and Cold-Water Refugee as identified tribal, federal, and state technical experts is approximately $12M/year.

Courtesy United States Geological Survey / CC BY-SA 3.0.JPG

Estuary Restoration

All migrating fish in the Columbia River must pass through the estuary twice in their life cycle. It was not until the early 2000s that Corps recognized the importance of habitat restoration in the estuary and began funding work to restore important habitat to support food webs and water quality improvements. Considerable work has been funded through the Corps and BPA to restore priority areas, but significant work remains. Due to the damming of the Columbia River the active channel and sediment transport through the plume no longer provide the necessary diversity to support robust food webs and refuge from water quality and predators needed for the transitioning salmon.

The total cost for continued estuary studies and actions as identified tribal, federal, and state technical experts is $6.5M/year for the next 8 years.

Lamprey

Pacific lamprey ("eels") hold great significance to the CRITFC member tribes for their subsistence, ceremonial, traditional, and medicinal purposes and ecological contributions. The goal of the CRITFC member tribes for Pacific lamprey restoration is to immediately halt the decline of Pacific lamprey and to restore lamprey throughout their range to self-sustaining numbers that support cultural, harvest, and ecological value. Pacific lamprey populations in the Columbia River Basin have declined drastically in the past half century due to a number of factors that include passage obstacles, entrainment, habitat degradation, poor water quality, contaminants, dredging, predation, poor ocean conditions, and climate change.

Blocked and delayed passage due to dams has severely impacted the ability for lamprey to reach their historic spawning habitat and has led to extirpation in the upper reaches of their range. Dams have altered the system for lamprey in all life stages and throughout their range. Ladders constructed for salmon are not suitable for lamprey due to differences in swimming style and ability. Lamprey use anguilliform swimming and use their sucking disc mouths to help propel them up surfaces. They are unable to maintain suction on 90-degree angles. Lamprey are not strong swimmers in comparison to salmon. As such, lamprey needs must be considered when constructing new passage or improving upon older structures at the dams.

Passage improvements for lamprey have been made at the mainstem dams, however more work is required. Roughly only ~ 50% of lamprey pass each consecutive dam during the upstream migration. Downstream passage is also problematic, lamprey are impinged on screens at the dams, inadvertently diverted and barged downstream with salmon, predated upon, endure poor water quality, and other threats.

The tribes and the Corps have developed an implementation plan to enact these actions to improve passage for Pacific lamprey. The cost of many of these improvements are significant and require multiple years of stable funding in order to be successful. Passage studies are required to monitor passage improvements and adjust or overhaul systems if the results of the studies suggest additional improvements are needed. A specialized miniaturized acoustic tag just for the small juvenile phase of lamprey has recently been developed for passage studies to understand the downstream migration (JLAT). These passage studies ideally would span multiple years and multiple dams, reservoirs, and tributaries. This is a significant cost that could take approximately 10 million to 20 million dollars to complete a robust study. Additionally, the JLAT tag needs to be commercialized to put it to work more easily.

The total cost for lamprey improvements and studies as identified tribal, federal, and state technical experts over the next 8 years is $165.1M.

"Before the non-Indians came, tribes managed the natural resources and protected them. We were taught that if you take care of the land and the resources, the land will take care of you."

— N. Kathryn Brigham, Umatilla, 2015

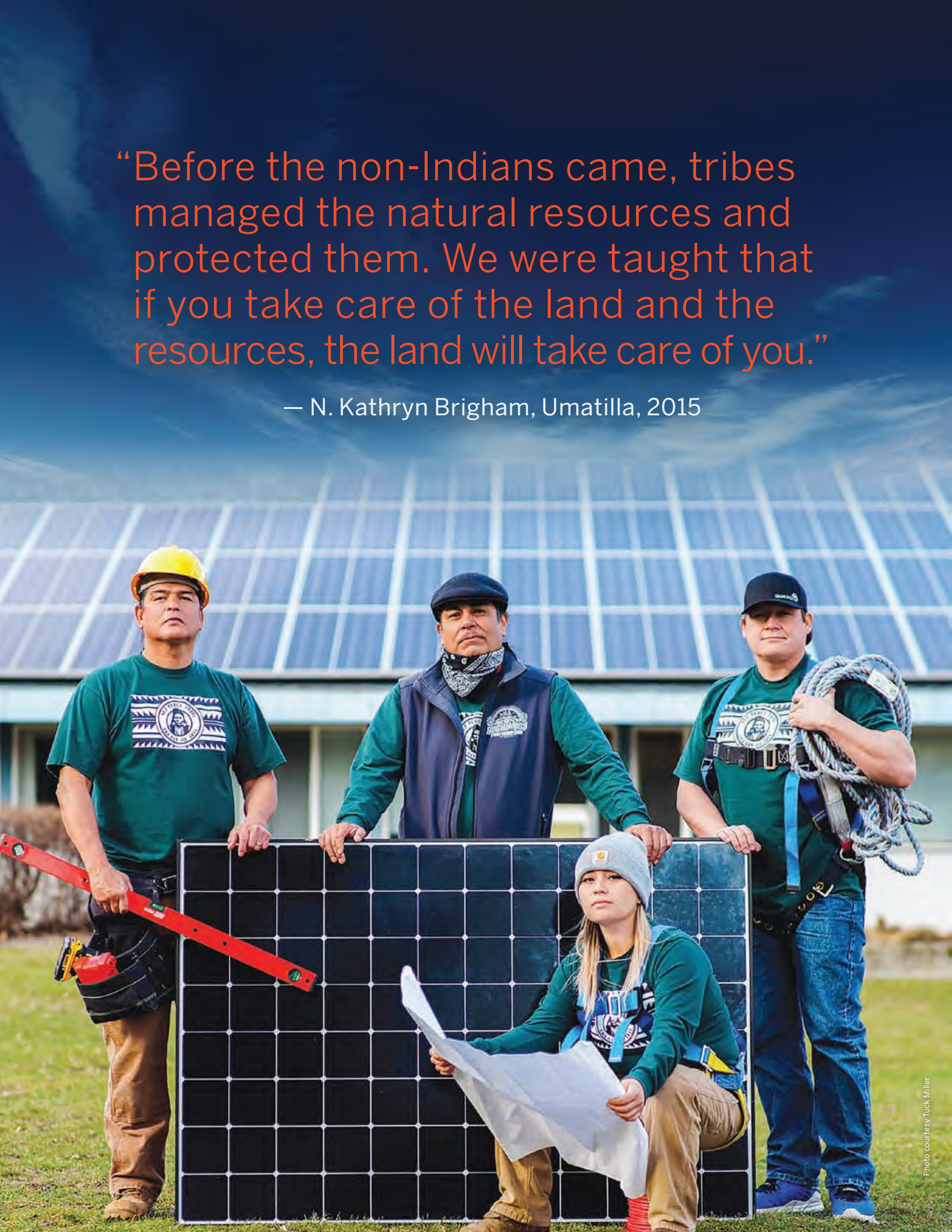


Photo courtesy Tuck Miller

APPENDIX D:

Energy Activities of CRITFC Member Tribes and Future Tribal Energy Leadership Opportunities

CRITFC developed a Tribal Energy Vision in 2003 and updated this vision in 2013. The four CRITFC member tribes have each applied the vision to their day-to-day government priorities. These tribal actions demonstrate their leadership in reducing damage to salmon and other fish and wildlife in the Columbia Basin, reducing emissions causing climate change and supporting a diverse and reliable energy resource mix that will lower energy costs and help recover abundant, harvestable salmon and other resident fish.

Energy Activities of CRITFC Member Tribes

Each of the four tribes has participated in studies and feasibilities of all possible energy solutions which could meet their goals, and which conform to the tribal culture. Feasibility studies and other similar actions have included reviews of energy efficiency options, wind energy generation potential (and any negative project impacts), solar generation projects, biomass project feasibility using local forestry resources, reservation hydropower generation and management, agricultural practices to save energy, natural gas projects and other potential projects.

All of the tribes have taken on some level of study or establishment of a tribal utility to give the tribe better ability to choose their own resources, control their power use, create jobs and provide essential, sustainable services to their reservations. Each of the tribes has invested in one or more personnel employed by the tribe to manage and operate the chosen energy projects.

Each tribe has had to consider the unique resources available on their reservation, and their unique political, cultural, and practical positions. These factors have included whether the tribe's reservation is in trust or has a checkerboarded land base (which impacts the tribe's jurisdiction over contiguous infrastructure), access to land with infrastructure for solar, whether a good wind resource is present in a place that does not have cultural impediments to development, whether there are existing hydro dams or hydro potential, and other similar factors. Each tribe has had to contend with different outside relationships with their various serving utilities, the ability to access outside commodities (such as natural gas), and their access to energy infrastructure.

Generally, the low cost of electricity in the region makes it financially more difficult for

renewable energy and new projects with new infrastructure demands to compete with existing markets. The hiring and training of local qualified personnel also presents a challenge unique to these rural communities.

Three of the four CRITFC tribes (Nez Perce, Umatilla and Yakama) have been officially "affected" by the Hanford nuclear waste site under the Nuclear Waste Policy Act of 1982. The U.S. Department of Energy Richland Operations Office is responsible for the cleanup at Hanford, which gives these three tribes a potentially different relationship with the U.S. Department of Energy and has other natural resource and partnership implications.

Each tribe has used available federal and other grants and technical assistance opportunities to assist in their energy planning, studies, projects, and decision-making efforts.

The following energy efforts are ongoing with the CRITFC Tribes.

Confederated Tribes of the Umatilla Indian Reservation[166]

General Information

There are over 3000 tribal members, about half of whom live on the reservation. The Umatilla Reservation totals 172,882 acres that flank the Blue Mountains of northeastern Oregon. Of that total, 90,315.54 are trust acres (52%) and in Individual Indian/Tribal ownership, including trust and fee. 48% is owned by non-Indians. The Umatilla Reservation's electricity is served by the Umatilla Electric Cooperative (in most of the residential and rural areas of the reservation) and by PacifiCorp (in the commercial and governmental area). Cascade Natural Gas also provides natural gas service on the reservation.

Energy Governance and Planning

CTUIR adopted an energy policy in 2009 to provide a long-term vision on the use of energy and the development of energy security and independence. Among the goals articulated in the energy policy are the desire to "Promote the development of clean and renewable energy sources...that build the CTUIR's energy independence..." and to "Develop strategies to

[166] The information regarding the energy activities at Umatilla was gathered from a review of public sources, and from an interview with Bruce Zimmerman, Tax Administrator for the tribe.

protect the CTUIR and its members from rising cost of energy through conservation…" The energy goals of the CTUIR are also succinctly summarized in the CTUIR Comprehensive Plan, where it states the desire of the CTUIR to "… actively pursue the reduction of greenhouse gases to sustainable levels by striving to conserve energy and developing energy independence for the sustainability of the Tribal community and its environment." The CTUIR Energy Policy further indicates that solar PV is among the most promoted energy technology, as long as development efforts are consistent with natural and cultural resource values.

Because of the major changes in energy technology, regional energy markets, tribal lessons-learned from past projects and a changed view of the "costs" of energy (including the financial costs, environmental costs, cultural costs, and other costs), CTUIR is updating its energy planning and tribal codes related to energy.

The tribes have designated staff focusing on energy issues. The tribe established an Energy and Environmental Sciences Program within its Department of Natural Resources (DNR). That department assists the tribe in meeting its energy and environmental goals. The tribal commercial functions are managed by the Department of Economic and Community Development (DECD), so a number of energy projects related to the tribal businesses are managed there. In addition, the tribal rights of way are managed at DECD in conjunction with the Land Management Department.

Various parts of the tribal code address energy related issues. CTUIR has adopted the Oregon Public Utility Commission's standards for net metering. The Land Use Development Code, which addresses zoning on the reservation, is going through an amendment process to clarify land related matters for residential and agricultural customers who want to take advantage of the existing utility net metering policies for small solar and wind. The code will also prohibit new wind unless it goes through a full tribal process and will limit other solar to 3 MW. These solar projects are proposed to be limited to industrially zoned lands. Any project larger than 3 MW must go through a more formal tribal approval process with various permits required.

Among CTUIR's business enterprises is Yaka Energy, a Section 17 corporation with an affiliated Nevada LLC. Yaka Energy is no longer operational. Yaka Energy focused on energy procurement and resale with a business objective to supply Fortune 500 companies, government agencies, investor-owned utilities and municipalities with energy commodities and energy marketing services. In addition to various energy marketing activities, a gas-fired powerplant was developed and fully permitted before the tribe decided not to move forward with the project in approximately 2006. With the decline in the economy and energy markets in 2009, this proved to be a good decision.

Outside Advocacy

The reservation's geographic location has led to it being a major transportation and utility corridor with numerous interstate energy and other facilities crossing tribal lands. The companies with facilities on tribal lands include the Union Pacific Railroad (which has crossed tribal lands since 1881) and Williams Companies (Williams Northwest has had gas pipelines on tribal lands since the 1950s and currently operates a 30-inch high-pressure gas pipeline). Various high-voltage electric powerlines also cross the reservation, and both Umatilla Electric Cooperative and PacifiCorp have distribution facilities on the Reservation. Cascade has gas distribution facilities. All these rights of

ways and service lines raise significant safety, environmental, natural resource, service, and financial issues for the tribe.

CTUIR has exercised their sovereignty through right of way negotiations to not only negotiate compensation for the use of their lands, but also to cover the costs of tribal services related to the rights of ways. Tribal services include law enforcement of trespass and illegal use of the lands, emergency response coordination with the energy and rail companies and tribal police, natural resources and ambulance services and administration of right of way uses. Third, the tribal right-of-way agreements govern all aspects of the right of way. The tribe now has numerous comprehensive right-of-way agreements.

These agreements have taken many years to develop and complete. In addition to compensation to the tribe for the use of tribal lands and resources, the provisions in the agreements include:

- A mandatory explicit consent to tribal jurisdiction and application of tribal law to the company's activities on reservation lands. If the company ever violates this agreement, the right-of-way is automatically void. In some instances when the tribe has presented this provision the company has left the table but then later has come back and accepted it. In one instance, a company refused to sign the agreement and moved the right of way off the reservation.
- Detailed list of facilities on the right-of-way with GIS coordinates which are incorporated into tribal GIS to pinpoint the location of every asset.
- Safety/emergency provisions. After one railroad right-of-way was negotiated and others were going through the process, a derailment incident occurred on the reservation. Within minutes, tribal police and emergency responders knew the exact location of the incident, the contents of every train car, the best route to access the site of the accident and had contact information for railroad officials. Because the emergency response worked so well between the tribe and Union Pacific, Union Pacific moved quickly to finalize all other pending agreements as beneficial not only to the tribe but to the railroad.
- Operational/environmental matters.
- A requirement for *annual* high-level meetings between the tribal leadership and the utility and company leadership, similar to a government-to-government meeting. Meeting locations alternate between the reservation and the company headquarters. They have been instrumental in developing good relationships.

Options Studied

Over the years the tribe has pursued many options for energy projects, such as the tabled gas marketing and generation project. As another example, the CTUIR Range, Agricultural and Forestry Department has considered a large-scale biomass project and ruled it out for the tribe's resources.

The Energy and Environmental Services Department is currently conducting explorations to determine the available geothermal resource. CTUIR is working with AltaRock Energy, Inc., HotRock Energy Research Organization, and the United States Geologic Survey (USGS). The project will determine whether a viable geothermal resource exists by studying the structural geology, rock outcrops, stratigraphy, and other signs of geothermal activity and will develop a conceptual model of the area and identify the best sites for future exploratory drilling.

Example Projects

- The **Tamástslikt Cultural Institute** is more than just a museum, it celebrates the traditions of Cayuse, Umatilla and Walla Walla Tribes and is the centerpiece of the Wildhorse resort and casino. In partnership with PacifiCorp, Cascade Natural Gas and the Energy Trust of Oregon, a study was conducted to identify energy efficiency and cost savings. The study led to the construction of a 40-meter 250 kW wind tower which supplements the tribal power needs, various energy efficiency activities, an efficient boiler, and covered solar parking structures.

- The tribes operate the **Kayak Public Transit System** which provides rural regional bus service southeastern Washington and northeastern Oregon with three fixed routes. Aside from providing a public transportation service, Kayak saves energy by providing a public alternative to single use automobiles.

- In 2018 the tribe installed the **Ántukš-Tińqapapt** or "sun trap" ground mounted 97 kW solar array. Over the anticipated 25-year lifespan (warranty) of the project, the tribes expect to save more than $450,000 in electrical utility bills and saving an almost 23-ton reduction in carbon dioxide emissions each year. The project also included LED lighting retrofit EEMs implemented across three tribal government buildings. The aptly named solar array supplies 100% of electric demand for three buildings—the Tribe's field station and the Kayak Public Transit Center bus barn and maintenance shop.
- Along with partners, CTUIR developed the **103MW Rattlesnake Wind Farm** west of Arlington, Oregon. Permitting began in 2002 and the project became operational in 2008. Permitting included a full Environmental Impact Statement. The wind farm spans 8,500 acres of ranchland that overlooks the banks of the Columbia River. The tribe sold the project to a developer and retains a financial interest in the project.

Appendix D

Courtesy Yellowhawk Tribal Health Center

- Yellowhawk Tribal Health Center is the first tribal building in the state to enroll in **Energy Trust of Oregon's "Path to Net Zero"** offering for buildings approaching net-zero energy use. Once certified Net Zero, this building will generate as much energy as it uses over the course of a year—a path the Eastern Oregon Tribe can be proud to walk. This building is 60 percent more energy efficient than a standard building of its type, and the estimated energy savings are 646,000 kilowatt hours per year. That translates to nearly $58,000 a year in savings, which will be invested back into the community. The building is accomplishing these savings through a variety of features, including solar panels, LED lighting, high-performance insulation and windows, and an efficient heating and cooling system that recovers heat and energy from the air.

- CTUIR maintains numerous connections with **Bonneville Power Administration (BPA),** including managing the land rights for BPA facilities on the reservation. For example, when CTUIR developed, built, and manage a light industrial and commercial business park known as the Coyote Business Park. The Business Park involved the replacement of power support structures of the high-voltage line that crosses the site. BPA replaced 10-12 wooden "H-frame" structures, each about 60 feet tall, with 7 to 9 steel poles and one lattice steel structure each about 110 feet tall on the portion of its Roundup-LaGrande transmission line that crosses the business park site.

Yakama Nation[167]

General Land/Energy Information

Roughly 10,000 people were enrolled members of the Yakama Nation in 2009 as descendants of the 14 tribes and bands of the Yakama Nation. The governance of the tribe is the responsibility of a 14-member tribal council, elected by a vote of the tribe's members. The reservation is 1.4 million acres in south-central Washington State. In 1963, most criminal and civil jurisdiction over tribal members was transferred from the tribe to the Washington state government under Public Law 280. The tribe started its own utility, and Yakama Power began service in 2006. Since its beginning Yakama Power has been actively pursuing utility expansion. While it has taken over much of the service to the reservation, Klickitat County Public Utility District and Pacific Power still provide electric service on some areas of the Yakama Reservation. The reservation is not served with natural gas.

Energy Governance and Planning and Outside Advocacy

The Yakama Tribal Council effectively delegated most of its internal energy functions to its tribal utility beginning with its Council Resolution GC-04-98 in 1998 to research the opportunity of a tribal utility. Yakama Power is governed by its Board of Directors, which consists of 7 tribal council members. The Nation received a relicensing settlement from Grant Public Utility District in 2007, which supported utility start-up expenses. Now, Yakama Power not only provides electric service to most of the reservation, it offers 20 GW internet, land line and cell phone service to the reservation and security services and cable television to some customers through fiber optic systems. All fiber is tribally owned and receives lease revenue from a local wireless provider. Yakama Power has a full requirements contract for power from Bonneville Power Administration but also develops its own renewable energy generation. Yakama Power advocates for tribal utility issues among federal, state, and local entities.

The Yakama Nation continues to actively pursue its Treaty Rights and otherwise advocate for its tribal sovereignty, including in energy related matters. For example, the Nation litigated Washington State's imposition of fuel taxes on tribal purchases. In 2019, the US Supreme Court[168] confirmed that citizens of the Yakama Nation are not required to pay a fuel tax to the state of Washington. A treaty signed with the United States in 1855 pre-empts the tax.

[167] The information regarding the energy activities at Yakama Nation was gathered from a review of public sources, and from interviews with Ray Wiseman, General Manager of Yakama Power.

[168] *Washington State Dept. Of Licensing v. Cougar Den, Inc.*, 586 U.S. ___ (2019); 139 S. Ct. 1000; 203 L.ED. 2d 301.

Options Studied

Yakama Power is responsible for developing all renewable energy it serves to customers. They are currently studying solar with an expectation of four ground-mount systems producing up to 1.25 MW. Their vision statement says, "The Yakama Nation will research and develop energy efficiency and renewable energy through a diverse portfolio of renewable energy projects and programs to become increasingly self-sufficient and energy independent, to reduce costs and enhance tribal economic opportunities and minimize impacts of climate change. The Yakama Nation will promote sustainable energy projects while preserving and enhancing the cultural, traditional and environmental resources and protecting the rights as outlined in the Treaty of 1855."

The Yakama Nation has studied its wind resource and has decided against supporting large scale wind energy on its traditional lands due to the presence of cultural significant sites on most high hill and mountain tops where wind farms want to be sited for the continuous winds there. Yakama Power is considering smaller scale wind generators for areas that do not present these cultural or other concerns.

The Yakama Nation has studied biomass energy. A 2010 study showed the cost of supply of wood fuel and transportation made the idea financially insecure with unknown future power market rates. The results showed that existing industries produce the cheapest supply of feedstock as a byproduct of their operations, while supplies harvested specifically for bioenergy were considerably more expensive. Fragmented land ownerships lead to the necessity of cooperation between owners and highlight the importance of a strong anchor supply close to the plant. Lastly, uncertainty in supply and cost parameters leads to larger ranges in available biomass, leading to reluctant investment in large plants.

Projects

Yakama Power's electric service to the Reservation is the most significant energy "project" undertaken by the Yakama Nation. Yakama Power's load has grown from about 3MW in 2006 to about 18MW in 2020. It started with the tribal campus, casino, and Yakama Forest Products with a condemnation of Pacific Power facilities.

In 2010, additional customers were added after the transfer of 43 miles of BIA distribution lines serving irrigation pumps. Yakama Power bought out some of Benton Rural Electric Association's lines in 2011 which brought the load to 5.5 MW. Yakama Power also began serving Wapato Irrigation Project in 2011 bring their load to 6.8 MW. In 2013, additional Pacific Power facilities were condemned in White Seam to allow the utility to serve the rodeo grounds, FEMA homes and Totus Housing Project for a total of 7.4 MW. A third Pacific Power condemnation was filed in 2015 which added the Wapato Industrial Park, Apas, mamchut, Wolfe Point and others.

In 2016 Yakama Power purchased the remainder of Benton Rural Electric Association's to bring the utility's load to 16.2 MW. A new bay was added in Pacific Power's Wapato substation to serve the new load. In 2018, Yakama Nation purchased the assets on Signal Peak road from Pacific Power bringing the load to over 17 MW. Yakama Power serves native and non-native customers.

In 2019, utility revenues were over $13 million. Their rates were lower than competing utilities on the reservation, with all-in residential rates of

Courtesy Yakama Power

$0.0726/kWh. Competing residential rates are almost $0.095/kWh (before taxes and fees).

One of Yakama Power's main missions is to provide employment for tribal members on the reservation. They developed a non-union Apprentice Training Program. Graduates from the program have included Yakama Power's electrical employees, plus 1 plumber and 2 HVAC professionals. Today, they employ 30 people, almost all Indians with all-Indian crews.

Their employees are some of the few all-Indian utility crews. Employees include 4 apprentice linemen, 7 journeyman linemen, 1 apprentice meterman, 1 journeyman electrician, 1 apprentice electrician, 2 fiber service splicers and 1 fiber implementation technician, as well as management and office staff. The utility has a full array of utility trucks and equipment with a large shop.

Utility facilities include 4 metering points where Bonneville power is delivered, 9 distribution substations, 590 miles of distribution line, and 95 miles of 24.5 kV sub-transmission. They anticipate the need for a 115 kV line to be initially operated at 34.5 kV.

Wapato Irrigation Project is a federal irrigation project originally built in 1868. It is maintained by BIA for seasonal irrigation; April through October, with 1,100 miles of canals to irrigate 176,00 acres on Yakama Reservation for tribal and non-tribal farmers and ranchers. While BIA still runs the irrigation project in coordination with the Yakama Nation Water Resources Program, the Yakama Nation received a transfer of Wapato's vintage electrical equipment from BIA in February 2008. The transfer included the transformers, generators, control systems, from Drops 2 & 3, and the 34.5 kV transmission line. The buildings at both drop sites are leased from BIA. The long-term plan is to revive all three generators in the irrigation project and add another three to generate about 8 megawatts. Yakama Power, along with Nation's Department of Natural Resources, the Tribal Council, US Department of Energy, the Wapato Irrigation Project (BIA) and Grant Public Utility District, began with an overhaul of the generator at pumphouse No. 2 (pictured below with local artist paintings on the turbine) near Harrah, which can now produce up to 2.5 megawatts, however transmission systems in the area limit the generation capability. Because Yakama

Courtesy U.S. Department of Energy

Power's contract with Bonneville permits only smaller added projects, power produced is sold to Grant County Public Utility District. Future plans include adding additional generation, including micro-hydro, to the project and expanding the Bonneville Power Administration substation and transmission facilities to accommodate the additional generation.

The Nation negotiated a settlement with Grant County Public Utility District related to the Priest Rapids Dam which impacted the Nation. Under the agreement, the Yakama Nation, through Yakama Power became a Priest Rapids Project power purchaser along with Grant PUD's 22 existing purchasers. Grant PUD markets the power on behalf of the Yakama Nation. Through 2009, the allocation was 20 average megawatts (aMW), 15 aMW from 2010 through 2015, and 10 aMW in 2016 through the remainder of the agreement. Like other power purchasers, the Yakama Nation pays project cost for power received. In recognition of the value of this power allocation, Grant PUD received rights to 75 percent of the renewable energy credits for the first 75 average megawatts of any renewable generation project developed by the tribe. Grant PUD will also receive the first opportunity to jointly develop new generation projects.

Confederated Tribes of the Warm Springs
Indian Reservation of Oregon

Confederated Tribes of Warm Springs[169]

General Land/Energy Information

The people of the Warm Springs reservation are Wascoes, Warm Springs Band (Tygh, Wyam, Tenino and Dock-Spus bands) and Paiutes who organized as a confederation in 1937 with a Constitution under the Indian Reorganization Act. In 1855, The Warm Springs and Wascoes (before the Paiutes moved there) signed the Treaty with the Tribes of Middle Oregon, which ceded 10 million acres to the United States. There are over 5000 tribal members today, most of whom reside on the 640,000 acre reservation in north central Oregon. The Tribal Council has 11 members, 8 elected positions (representing three districts: Agency, Simnasho and Seekseequa) along with three lifetime chieftain positions representing the three tribes of the Confederacy (Wasco, Warm Springs and Paiute).

The reservation natural resources include cultural resources, rangeland (ranching and wildlands), agriculture (the tribal farm grows grain hay, alfalfa hay and orchard grass; vegetable, flower, grass legume and grain seeds), forests, rivers and lakes, fish and wildlife and birdlife. The reservation is bordered by the Deschutes River (with Lake Stimtustus behind Pelton Dam and Lake Billy Chinook behind

[169] The information regarding the energy activities at Warm Springs was gathered from a review of public sources, and from interviews with Jim Manion, General Manager of Warm Springs Power and Water Enterprises.

Round Butte Dam), the Metolius River and Jefferson Creek. Crossing the reservation is the Warm Springs River and other creeks.

The tribal website states, "We ask, 'What impact will this have, both positively and negatively, seven generations from now?'" Natural resource considerations are paramount in all energy development options.

Energy Governance and Planning and Outside Advocacy

Warm Springs Water and Power has been delegated many of the energy functions for the Confederated Tribes of Warm Springs. However, the Tribe maintains an active Natural Resources Department and a Public Utility Branch who manages water, wastewater, solid waste and maintenance of over 90 tribal buildings. The tribe manages a Low-Income Energy Assistance Program that offers assistance with electrical bills or wood. The tribe also manages a Public Transit program through the Planning Department.

Jim Manion, General Manager of the Warm Springs Water and Power Enterprise participated as a member of the Indian County Energy and Infrastructure Working Group, operated by the United States Department of Energy to bring government and tribal leaders together to collaborate and gain insight into real-time tribal experiences representing obstacles and opportunities in energy and related infrastructure development and capacity building in Indian Country.

Options Studied

Warm Springs Water and Power has actively been pursing renewable energy for the past several years. They started with a resource inventory of reservation lands and compiled a list of potential resources. They assessed the two with the highest potential, wind and geothermal.

- Beginning in 2003, Warm Springs completed a wind energy inventory by installing met towers across the reservation. The study concluded that they do have a viable wind capacity factor sufficient to develop at the Mutton Mountain site. The environmental review identified birds of prey that could potentially be impacted, so the tribe has decided not to pursue a wind generation project at this time.
- The next was to look into geothermal, as the tribe has a known "warm spring" resource. Preliminary geothermal reconnaissance began in 1990. A Memorandum of Understanding was signed with a private company. While there was a promising resource in the southwest corner of the reservation, energy markets did not support the costs of the projects. Warm Springs Water and Power has conducted all necessary Geotech work along with subsurface work, drilling temperature gradient holes. The enterprise continues to explore funding options to drill a test production well to quantify the resource. Transmission access is a challenge for this resource as it is located in a remote and timbered landscape.
- Recently, Warm Springs Water and Power has started to advance the tribe's solar potential. They have identified a developer and are exploring access to the grid to build out a large-scale solar farm. We are considering a 100MW or larger commercial scale project if we can gain access to the grid. They recognize the need for new renewable resources over the next 5 years, and with the renewable energy standards on the west coast, they believe this could be a valuable resource to develop.

Example Projects

- **Warm Springs Power and Water Enterprises** is run by an Enterprise Board appointed by Council, and a General Manager. They manage the Tribes interest in the largest hydroelectric project within the State of Oregon as a co-manager with Portland General Electric (PGE) of the Pelton/Round Butte Hydroelectric Project located on the Deschutes River which borders the reservation. In 1955, the Tribes approved the building of the first powerhouse, the Pelton Dam and the second dam, the Reregulating Dam. The Tribes reserved the exclusive right to develop power generation at the Reregulating Dam if it was ever found to be economically feasible. In 1964, the Tribes approved construction of the third dam, the Round Butte Dam. It wasn't until 1979, when the energy market improved and federal law was passed allowing private developers to develop hydroelectric sites, the Tribes elected to exercise their option to construct a hydroelectric project at the reregulating dam.

The tribes entered the energy generation business in 1982, with the completion of this hydroelectric plant, which was the first tribal sovereign to receive a Federal Energy license. Warm Spring installed a 19.5 MW Bulb Kaplan turbine in the last of a series of dams on the Deschutes River. In 2001, the federal license for this hydroelectric complex ended. The Tribes & PGE entered into a Global Settlement Agreement to form a partnership to jointly own the Pelton/Round Butte Hydroelectric Project.

Today, the Tribes are a one-third partner in the project and have 100% ownership of the Reregulating Dam powerhouse, increasing the energy capacity to 170MW. By 2037, the tribes have an option to become the majority owner of the entire project. In 2021, the will be advancing the option to increase their ownership interest in the Pelton Project, taking the ownership interest to 49.9%. The partnership has proven beneficial to both Warm Springs and PGE, providing important revenue to the Tribes, and reintroducing salmon and steelhead above the project while providing carbon-free power to the grid that feeds Warm Springs and to the PGE grid.

- **Warm Springs Forest Products:** In 1970, three 3MW steam turbines were installed at Warm Springs Forest Products. In 2004, the tribe worked with state, federal and private firms to expand the biomass program to a 20MW cogeneration plant. In 2016, the tribe's forest products lumber mill shut down due to a reduced supply of logs, an aging plant and a changing economy.
- **Warm Springs Ventures** maintains a carbon offset venture that sells carbon offsets to major polluters. The tribal forest management plan for the 2,200 acres coincides with the practices called for by the carbon sequestration credit program.
- **Small-Scale Solar:** Sunlight Solar has completed two projects with the Confederated Tribes of Warm Springs. The first project was completed in 2010 on the Warm Springs Media Center building which houses the local radio station KWSO and newspaper SpilyayTymoo, the second is at the Warm Springs K-8 Elementary and includes a 213 solar panel, 58.565 kW system to power the school. Annually, the solar system is expected to save the school $4,000.

Nez Perce Tribe[170]

General Land/Energy Information:

The Nimiipuu people have always resided and subsisted on lands that included the present-day Nez Perce Reservation in north-central Idaho. Today, the Nez Perce Tribe is a federally recognized tribal nation with more than 3,500 citizens.

The current Reservation consists of 770,000 acres of which 124,000 are tribally owned. It was established by treaty with the United States government in 1868. Parts of five Idaho counties, Nez Perce, Lewis, Latah, Idaho and Clearwater Counties, are located within the reservation boundary. The cities of Lapwai and Kamiah serve as Tribal centers on the east and west ends of the Reservation. U.S. Highway 95 runs north and south through Idaho, and the reservation, and serves as a major interstate highway. Highway 12 runs east and west through Idaho's panhandle. Nez Perce Reservation lands consist of productive dry-land wheat farms that border on the Clearwater and Nez Perce National Forests. Beside arable hill tops and river bottoms, the reservation includes forested river canyons and steep, non-arable hillsides. The chief economic basis of this entire region is in agriculture and timber products.

[170] The information regarding the energy activities at the Nez Perce Tribe was gathered from a review of public sources, and from interviews with Stefanie Krantz, Climate Change Coordinator for the Nez Perce Tribe Water Resources Division.

The Reservation is currently served with electricity by Avista Utilities and by Clearwater Power Company. Natural gas service is provided in some places on the reservation by Avista. Although Idaho's electrical rates are among the lowest in the country, the Nez Perce Tribe's electrical bills are significant to the operating budget every year. Tribal programs are located in forty some buildings, in six counties, in two states. Ninety-five percent, or more, are heated electrically. The age of the Tribal office buildings located in Lapwai, Idaho vary from forty to over a hundred years old, and most have not been updated. The tribe has expressed concerns over the reliability of existing power systems and maintaining a reasonable cost of service.

Energy Governance and Planning and Outside Advocacy

The Nez Perce Tribal Executive Committee (NPTEC) has taken steps to provide specific energy leadership. They have established a Climate Change Subcommittee of the Council to address the ever-changing climate and natural resources, mitigation strategies, energy consumption, energy developments, environmental health, workforce development, and all efforts geared to going green, utilizing sustainable methodology, and having sustainable solutions for and on behalf of the Nez Perce Tribe. They have also created a full-time position of Climate Change Coordinator in the Water Resources Department of the Natural Resources Office. They are currently hiring a Climate Change & Energy Planner VISTA Member through AmeriCorps to assist in climate adaptation, policy, and resilience planning efforts.

The tribe has an active water utility run by a Water Utility Board. Their goal is to provide clean potable water for customers as well as maintain a reasonable rate structure that customers can afford. Water technicians operate and maintain the three water systems (North Lapwai, South Lapwai, and Kamiah) and the two sewer systems (Kamiah and North Lapwai) serving the Nez Perce Tribe. Water utility tasks include reading meters, water testing, repairs and planning future system upgrades.

In 2010, an Energy Committee was formed to guide the energy efficiency and energy development efforts for the Nez Perce Tribe. The committee consists of a diverse membership to ensure thorough planning. The members include a Grants Coordinator, Economic Development Planner, Environmental Planner, Construction Manager, and Energy Technician. The committee is recognized by the NPTEC and is invited to energy related discussions concerning the Tribe. The Energy Committee represents the government side of the Nez Perce Tribe, therefore it only works with not-for-profit projects.

The Energy Committee received a grant from Avista for a Strategic Energy Plan to ensure sustainable and environmentally responsible energy use. The goal of a strategic energy plan is to provide a roadmap to meet current and future energy needs in an economically, socially, and environmentally sustainable fashion. The steps taken in an energy plan depend on energy resource options, energy needs and forecasts, setting priorities and organizational structure. A consultant will be facilitating the final draft and facilitating tribal leadership, tribal programs and tribal community input through surveys and community meetings.

In an effort to prepare for changes to their homelands' ecology, the Nez Perce Tribe's Water Resources Division created a climate change adaptation plan for the Clearwater River Subbasin in 2011. The plan focuses on climate impacts to water and forestry resources, two areas of natural resource management that are both culturally and economically important to the Nez Perce Tribe. This plan will increase awareness of climate change issues in their

region and is also intended to aid the Tribe and regional organizations in integrating climate adaptation into existing and future management plans. Adaptation plan goals include:

- Creating partnerships to research local effects of climate change on water resources, forestry, and the economy.
- Including climate change adaptation assessment data, goals, and objectives into local and regional planning documents.
- Affecting a change in planning and zoning regulations along waterways and restoring the 100-year floodplain.
- Protecting and restoring water quality and quantity for human health and anadromous fish.
- Managing wildfire risk.
- Reducing and/or reinforcing infrastructure in landslide-prone areas.
- Developing ecologically connected networks of public and private lands to facilitate fish, wildlife and plant adaptation to climate change.

A 500kV Bonneville Power Administration ("BPA") transmission line crosses through the area and connects to the BPA Hatwai 500kV substation. A right of way was negotiated between the tribe and BPA in approximately 2013.

In 2014, the Nez Perce Tribe stopped energy companies from shipping "megaloads" of equipment and commodities through its reservation in Idaho from Alberta tar sands. After tribal protests, a federal judge halted further traffic, in part due to the state's failure to consult the tribe.

In 2019, The Nez Perce Tribe, Pacific Rivers and Idaho Rivers filed lawsuits against the Oregon Department of Environmental Quality to stop the relicensing of the Hells Canyon Complex of three dams along the Idaho-Oregon border operated by Idaho Power.

Options Studied

- In 2012, the Nez Perce Tribe Energy Committee selected TSS Consultants (TSS) to prepare a **Waste to Energy Feasibility Study** for projects on the Reservation. They studied utilizing sustainable and economically available waste sourced from the region

located within and tributary to the Nez Perce Reservation. The projects would have been scaled to meet electrical and thermal energy needs of select community buildings included in the communities of Lapwai, Orofino, Kamiah and Kooskia. An energy load assessment of targeted buildings as well as a site review/waste resource assessment was completed. Because the economy of the Tribe and surrounding region has been tied directly to forest products manufacturing, timber harvesting and agriculture, forest biomass was included in the resource assessment along with other potential feedstocks including agricultural by products, tree trimmings, and municipal solid waste.

- A **Tribal Utility Prefeasibility** was completed in 2013, the Tribe requested Technical Assistance from the US Department of Energy for a Tribal Utility Prefeasibility Study for selected areas of the reservation. Because the area included lands that were not held in trust, the study indicated that a tribal utility for the entire area could be difficult from a jurisdictional/regulatory point of view and that the area could be adjusted to include only tribal loads, or that the tribe could franchise current service to negotiate different service or rates.
- In 2019, a **Green Wastewater Study** feasibility study was conducted by the National Renewable Energy Laboratory to find if the tribe has options for greener wastewater treatment. NREL also identified some tribal housing as suitable for solar energy development.
- **Micro wind and microhydro:** As of August of 2020, the tribe is considering both small wind and micro hydro projects.

Example Projects

- The tribe operates a **Low Income Home Energy Assistance Program (LIHEAP)** through an annual grant from the US Department of Health and Human Services and other funds. The program provides heating assistance and crisis assistance. Qualifications for the heating program depend on income, fuel type and the percentage of income used for energy. The crisis program considers factors such as medical conditions, children and elderly residents. Applications are online.
- The Water Resources program operates an **Energy Efficiency Initiative**. See: http://nptwaterresources.org/energy-efficiency/
  - As part of the stimulus plan in 2009, the tribe received $97,000 for energy efficiency. The tribe also received $508,000 as part of a Native American Housing Block Grant for new construction, acquisition and rehabilitation including energy efficiency and conservation, and infrastructure development.
  - In 2011, utilizing $67,000 of the U.S. Department of Energy's Tribal Energy Program funding, energy-efficiency upgrades were installed in five Nez Perce Reservation buildings that house a large portion of the Nez Perce Tribe's governing entities. The upgrades included replacing lighting fixtures and windows as well as adding insulation and motion sensors. As a result of the upgrades, the Tribe's electrical energy consumption is estimated to be reduced by 30%, thereby reducing the cost to operate the Tribal physical plant and freeing up funds for other use. The upgrades will also provide a comfortable working environment for Tribal employees and are expected have a minimum annual energy cost savings of nearly $14,000.

In the first month after completion, a comparison between August 2011 and August 2012 (with an average temperature increase of one degree) electrical bills showed more than $1,200 in electrical cost savings to the Tribe. Based on this initial savings information, it appears that the project results may exceed the 30% savings goal that was initially set for the Tribe in these buildings.

- The tribe is currently planning a recycling education program.
- The tribe provides solar panels on schools and a "**Solar 4R Schools**" curriculum to support STEM classes in its school districts. Solar 4R Schools provided a renewable energy teacher training workshop to area teachers along with customized, durable science kits for four school districts valued at approximately $12,000. Teachers at each participating school will use these science kits alongside their multiple existing environmental stewardship and sustainability initiatives. Energy monitoring of their PV system and live solar energy data displayed at Solar4RSchools.org gives classrooms nationwide the ability to chart, graph and analyze the system's performance for educational purposes. The solar systems include a 4.48 kW solar array at the Lapwai School District and 4.48kW solar array at the Orofino School District.
- In February 2015 the Nez Perce Tribe completed a 10kW **Solar PV** demonstration system at the Tribal Hatchery Complex in Juliaetta, Idaho. It was funded by BPA and the Nez Perce Tribe. As a Renewable Facility, this project will function as an ongoing community education tool by teachers in four area school districts to supplement sustainability education for students throughout the Nez Perce region.

Photo credit Clean Energy Bright Futures

- **New Solar Initiative:** In September 2020, the tribe, with RevoluSun, a Hawaii company, is installing additional solar with battery backup, including one for the Pineewaus Community Center, one for the waste-water treatment plant in Lapwai. RevoluSun will providing training for tribal members in the installation. In the future a rooftop solar system is planned for the fisheries office and the clinic.
- **Carbon Sequestration Program:** The Nez Perce Tribe's Water Resources Division received a grant and technical support from the Model Forest Policy Program (MFPP) of the Climate Solutions University (CSU). In the mid to late 1990s, the Nez Perce Forestry & Fire Management Division began developing a Carbon Offset strategy to market Carbon Sequestration Credits. The tribe planned to reinvest revenue from the sale of carbon to acquire previously forested lands and then replicate the process with additional afforestation projects (planting trees on land that was not previously forested). This effort would also contribute to the tribe's goal of acquiring former tribal lands. Subsequent carbon offset projects have included wildfire rehabilitation (restoration of forests heavily damaged by wildfire) and forest development (reforestation where past forest regeneration practices failed). This first trial afforestation project became known as the "Tramway Project". The purpose of this initial project, about 400 acres in size, was to establish

marketable carbon offsets, develop an understanding of potential carbon markets, and cover the costs of project implementation and administration. Since the initial planting of the Tramway Agricultural Conversion / Afforestation Project, the Nez Perce have greatly expanded the program to include several other agricultural conversion projects as well as two additional types of projects, fire rehabilitation and forest development (defined earlier in the document). These projects are now separated into two different carbon offset portfolios, one portfolio containing only the afforestation (agricultural conversion) projects and the other portfolio containing the fire rehabilitation and forest development projects. It is this second portfolio (approximately 65.3% of the 3,375 total acres discussed earlier) that was committed to the CCX with the help of the NCOC. In July 2007, the Nez Perce Tribe signed a Contract with the NCOC and the CCX (for credits from 2003 –2010 on approximately 2,205 acres) and had the first actual sale in December 2007. The initial contract expired in December 31, 2010. Other projects are hoping to extend the carbon sequestration project, including a carbon cycle modeler which models the contribution of farmlands to carbon and a related sequestration through agricultural projects.

- The tribe has used the Volkswagen settlement funds to consider older tribal vehicles to plug-in hybrid **Electric Vehicles**. There are currently two charging stations on the reservation.

Tribal Energy Leadership Opportunities

The significant changes in the environment, the energy industry, energy economics and markets, energy technologies, public awareness and government policy are bringing astonishing opportunities for tribal energy actions. As shown above, tribes are frequently community and national policy leaders in employing ideas and technologies to solve environmental and natural resource problems. In particular, the existential environmental problem of climate change requires tribes to consider "energy" in many new ways. Environmental sustainability takes on broader and more critical meanings. As such, new approaches to meeting a challenge of environmental sustainability are needed. Some suggestions for tribes to additionally implement energy policy and technology to meet the goals set in this Energy Vision are set forth here.

First, the way in which tribes, as sovereigns, address, or can address energy issues is expanding. Tribes have long recognized that "energy" is not just about meeting electricity needs at a reasonable cost, more efficient hydroelectricity and replacing fossil fuels with renewable sources. Meeting an ambitious Energy Vision requires application of the principle of environmental/energy sustainability to all walks of life. In particular, tribes can consider "energy" in the following expanded ways.

- Water as an energy resource. In addition to major ongoing work related to watersheds and river operations, tribes may consider local water pumping, water quality, irrigation infrastructure and techniques and other local uses of water and water infrastructure. Permitted and unpermitted uses and of tribal water rights can also be considered.
- Housing as a tool for meeting the Energy Vision and for improving quality of life for

tribal members has often been overlooked. Housing on most Indian reservations is known to be substandard and not culturally appropriate. Poverty leads to not only energy inefficient homes but structurally unsound and even dangerous situations. The energy costs of poor housing, both in inefficient use of energy and unsustainable building products are very often much higher than in urban centers. Further, the problem of overcrowding has led to health issues. Poor financing options limit the flexibility for tribes to build higher quality or newer technology homes. Rethinking all aspects of housing (both existing reservation homes and new construction) is a major opportunity for cutting edge improvements.

- Just as housing can be a tool for meeting energy goals, all tribal buildings and infrastructure can be improved to better assist in meeting the Energy Vision. Just as every new building's financing includes its HVAC systems, the financing for every new building could include its own energy sources. An analysis of buying energy features up-front against the cost of purchasing power or other energy sources long term can be made common practice to assure both lower costs and self-sufficiency.
- Education is the strongest tool there is for long-term improvement in energy use and energy systems. Tribal schools and tribal meetings can both provide substantial energy education to their members, and to third parties. Application of creative ideas for meeting an Energy Vision through schools and other gatherings is an opportunity. (For example, "Energy Bingo" for tribal elders where the prizes are energy efficiency products with information about each one described during the calling of numbers.)
- It is likely that there will be new funding in the coming years for infrastructure. Energy planning when infrastructure is considered can be a game-changer for how infrastructure is used and how goals can be met. (For example, roads with bicycle lanes, easily accessible electric charging stations, carpool and transit opportunities, new technologies for water and sewer systems, etc.)
- All the tribes have members who are allottees and most reservations have allotments both within tribal lands and on traditional territories. For the most part, these allotments have been underutilized and not considered during tribal planning or during creation of federal policies. With sometimes half of "tribal lands" being subject to allotments, can new policies or programs be created to assure that these lands are part of the sustainability solution?
- All the CRITFC tribes have strong agricultural (including forestry) cultures. How can the Energy Vision be implemented through better, or improved agriculture and forestry practices, partnerships, or programs?

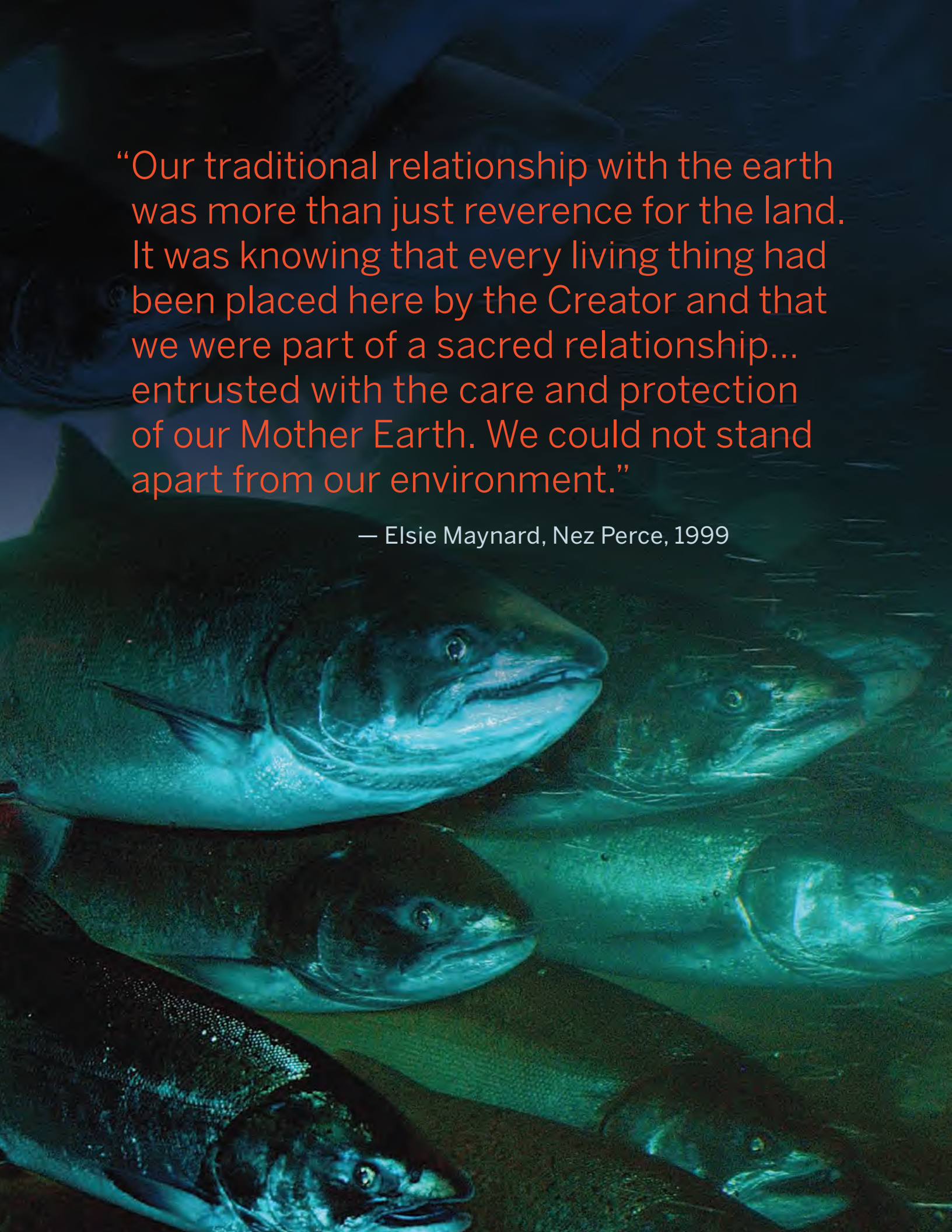
"Consideration of energy" here means that tribes (and CRITFC) can attack energy related problems with many tools:

- Tribes can legislate Tribal Energy Codes to create reservation goals, policies, procedures, funding and programs to assure that the Energy Vision is implemented within the reservation.
- Tribes can apply for and appropriately manage funding from federal, state, local and private sources to meet goals and to improve application of new and cutting-edge technologies.

- Tribes can use their political leverage and longstanding cultural wisdom to influence public opinion and government policy.
- Tribes can lead by example.
- Tribes can develop partnerships with private institutions, educational bodies, local governments, utility and energy industry players and others to further the Energy Vision and create buy-in by entities that may not otherwise be involved in improving the energy successes.
- Tribes can create local education programs for their own students and people and can work with outside educational entities to expand understanding of environmental/energy sustainability.
- Three of the four CRITFC Tribes were impacted by the Hanford nuclear site. Can the resulting responsibilities and relationships be leveraged to improve tribal energy options?
- Intertribal organizations have had a history of partnering with specific expert entities to attack specific goals important to the organization. If CRITFC or any of its tribes determine that an energy idea could be pursued, a pilot project can be developed which can benefit the community as a whole (local, regional, federal, international). It can be initiated through partnerships and likely funded by third parties.

Some particular cutting-edge technologies and new issues are up and coming for tribal consideration. These include:

- **Batteries:** The decreasing costs of batteries, the need for energy storage and new funding sources will likely create new opportunities for battery use in the next ten years.
- **Electric Vehicles and Vehicle Charging:** The development of new electric vehicle technologies, their purchase by government agencies, their decreasing costs and the need for new charging stations will transform tribal gas stations, truck fueling, and electrical infrastructure and generation. Tribes can be on the transforming edge of this revolution. Tribes could consider contributions to and investment in electric car technology programs, as well as charging infrastructure.
- **Microgrids:** With the fragility of the larger grid, utility policy changes being considered to permit more distributed generation, and the development of more sophisticated utility infrastructure meters and controls microgrids are under development for many critical needs facilities (military, hospital, government, etc.) Tribes are leaders in new microgrids, often because they can set policies for on-reservation loads that do not need to wait for state utility policy to be approved. Tribes also have funding sources which encourage new technology uses. In the next few years, most tribes will likely develop at least one microgrid.
- **Capacity:** With the transformation of energy markets to finer points of cost allocation and added renewable energy opportunities comes the need to balance energy generation with capacity reserves. "Resource Adequacy" is already a "new" additional significant cost for utilities in California and a new line item for costs of doing business. "RA" is being addressed in most energy markets and rate setting processes. Needed generation or storage resources specifically to meet capacity needs are under consideration by most utilities and government utility commissions. This change will impact the Energy Vision and maybe a point of consideration during next versions of the document.



"Our traditional relationship with the earth was more than just reverence for the land. It was knowing that every living thing had been placed here by the Creator and that we were part of a sacred relationship... entrusted with the care and protection of our Mother Earth. We could not stand apart from our environment."

— Elsie Maynard, Nez Perce, 1999

APPENDIX E:

Analysis of Meeting Peak Demands

E.1
Introduction

SECTION 3.1 above describes recommendations to reduce peak loads and includes recent information of the costs of expanding the region's transmission and distribution system. CRITFC is seeking additional information on those costs and the potential to defer or avoid some transmission and distribution costs by reducing peak loads, increasing energy efficiency, and promoting on-site solar and other distributed generation. CRITFC staff are interested in working with regional energy agencies and utilities to continue to update this important information.

SECTION E.1. provides new analysis of the high costs associated with building transmission and distribution lines. These high costs should be considered when evaluating the cost effectiveness of alternatives such as energy efficiency, on-site solar and other distributed generation options. CRITFC believes that a consideration of the full cost of generating or saving energy plus the cost to deliver it should lead to better resource decisions. It also provides updated information on peak loads for four investor-owned utilities in the region.

SECTION E.2 was developed for the 2013 Energy Vision to provide details on the high costs of meeting peak demands. CRITFC did not have sufficient resources to update this analysis with current costs; however, we believe that the general magnitude of the very high costs of meeting peak loads should be included in the analysis of efficiency measures compared to other options, including additional T&D.

APPENDIX C provides details on the recent changes in the operation of the dams to integrate renewable resources. Those issues are not addressed in this Appendix.

E.1.A. Background Discussion

Historically, regulated utilities have priced power at the average cost of delivering that power to consumers; they have not varied the cost much by time of day or season of the year. But power has more value when the demand for it is high and less when the demand for it is low. It also costs more to deliver power when demand is high because of additional, often higher-cost generators being called upon, higher line losses, and congestion in the transmission grid. Consumer electric rates that are the same throughout the day and throughout the year cause economic distortions of resources and have been overlooked for a long time because the price of power was very low. Our analysis shows that the costs of meeting peak loads is very high for consumers and for fish.

The value of the river system is distorted by this type of pricing strategy when hydropower operations on the river are designed to follow loads as they ramp up and down. These fluctuations in river flows kill millions of young salmon every year. Higher prices during peak energy use periods would dampen the peaks and reduce the stress on the hydroelectric system to follow them.

CRITFC continues to recommend a transition to time-of-use pricing of electricity. From an economic allocation of resources perspective, the ideal pricing strategy would be to price power at its full cost at all times, with costs fluctuating throughout the day. Full costs would cover the

cost of generating the power and the costs of the transmission, distribution, and support systems to deliver it. This pricing strategy would, over time, reduce costs and reduce the damage of river operations on fish and wildlife.

E.1.B. Current Use of the Hydropower System Hurts Salmon and Consumers

The day-to-day and seasonal operations of the hydroelectric system to meet peak electricity loads cause fluctuations in river levels that continue to kill salmon and other important fish species. The recommendations in this *Energy Vision for the Columbia River* are designed to reduce this problem while reducing costs for utility customers. As described in more detail below, the cost of delivering (transmission and distribution only) the highest 15 percent of peak energy to consumers ranges from 79 cents to $1.19 per kilowatt-hour—the average consumer pays about 8 cents per kilowatt-hour for delivered electricity, so these peak delivery costs are more than ten times higher than the total-average electricity costs. The cost of serving the highest peak loads range from 80 to 120 dollars per kilowatt-hour—a thousand times higher than average consumer costs. These high costs are melded into every consumer's electric bill. Reducing peak loads would also save an estimated $800 million per year in planned expansions of the transmission and distribution system.

Hydropower is used to serve peak loads because dams can react to demand by quickly putting more or less water through the turbines that generate electricity. Serving peak loads with hydropower kills millions of juvenile salmon every year. During certain times of the year, so much water is drawn down to generate electricity that salmon redds (gravel nests where salmon lay eggs) are uncovered or dewatered and their eggs die. Daily fluctuations change river water levels and juvenile fish that feed and live near the shore can be stranded and die when water levels are reduced. Migration of fish is interrupted when flows decrease at night because there is less demand for electricity and therefore less water moving through the reservoirs behind the dams. Fluctuations in reservoirs hurt resident fish by dewatering habitat and food supplies and reducing nutrients in the reservoirs.

Additionally, the water held behind storage dams for future power generation—for example, for summer peak loads to provide air conditioning—would, under natural conditions, be in the river aiding the swift and timely downstream migration of young salmon. Saving this water for summer energy production alters the natural (or normative) river conditions that aid juvenile salmon migration and would help in the restoration of fish to harvestable levels.

While changes in operations have lessened the frequency and severity of these occurrences, their effects are still significant.

E.1.C. Transmission and Distribution Lines Have High Economic and Environmental Costs

As discussed in SECTION 3 above, there are significant economic and environmental costs associated with the existing and new transmission and distribution lines.

CRITFC estimates that BPA and four investor-owned utilities spend approximately $8.2 billion on transmission between 2016 and 2020. Of this total, BPA spent $1.4 billion on transmission capital expenses between 2016 and 2020 and is projecting another $2 billion between 2021 and

2025[171] for a total of $3.4 billion for the ten years between 2016 and 2025. **(TABLE 9)**

The funding for expansion of BPA system represents about half theses total costs. BPA spend $601 million between 2016 and 2020 and is project is projecting a transmission expansion program that is budgeted at $730 million over the next five years.

CRITFC was able to compile distribution and transmission costs from the past five years for four investor-owned utilities in the region that totaled $6.8 billion. The information for the investor-owned utilities did not have details on expansions. CRITFC was not able to find similar information for municipal and public utility systems.

The information in **TABLE 10** was compiled from information that investor-owned utilities file with the Securities and Exchange Commission in what is referred to as their 10K filings[172]. It shows data for the value of each utility's transmission and distribution system in 2016 and 2020. The change column represents the increase in each system.

The information did not have enough detail to determine how much of these funds were spent on activities that could be reduced or delayed if additional energy efficiency, on-site solar, and peak-demand reduction programs described in this document had been implemented.

CRITFC found one data source that provided some additional detail for Portland General Electric Company. **TABLE 11** shows a breakdown by various distribution functions for 2016 through 2020 that total $1.5 billion[173]. For example, spending on distribution expansion or upgrades for capacity totaled $248 million between 2016 and 2020—about 17 percent of the total distribution spending. The expansions or upgrades for reliability and power quality totaled $372 million for the same period—about 25 percent of the total. Spending for new customer projects totaled $423 million—about

TABLE 9. BPA Transmission Expansion and Upgrade Costs (Millions $)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
BPA Expansion	$202	$75	$105	$142	$77	$124	$145	$165	$150	$146	**$1,331**
BPA Total Transmission	$381	$276	$264	$281	$222	$283	$357	$377	$425	$565	**$3,431**

TABLE 10. Changes in Utility Plant for Transmission and Distribution Based on SEC 10K Filings (Millions $)

	Transmission			Distribution			Total Change
	2016	2020	Change	2016	2020	Change	
Avista	$683	$863	$181	$1,525	$1,979	$454	**$634**
PacifiCorp	$5,916	$7,654	$1,738	$6,414	$7,696	$1,282	**$3,020**
Portland General	$518	$970	$452	$3,351	$4,136	$785	**$1,237**
Puget Sound Energy	$1,308	$1,495	$187	$5,288	$7,029	$1,741	**$1,928**
TOTAL	**$8,424**	**$10,982**	**$2,558**	**$16,577**	**$20,839**	**$4,262**	**$6,820**

[171] BPA Historical & Future Capital Spend, page 8 of presentation on Integrated Program Review 2, March 2, 2021.

[172] The formats for the SEC 10K reports vary somewhat between utilities, the Utility Plant values are typically on pages 200–206.

[173] PGE distribution DRAFT_Baseline_requirements_version_0.xls Tab Baseline 4.1.e. https://portlandgeneral.com/about/who-we-are/resource-planning/distribution-system-planning

TABLE 11. Distribution Spending Dataset

	2016	2017	2018	2019	2020
Age-related replacements and asset renewal	$49,154,093	$84,237,345	$85,596,952	$87,070,673	$85,538,736
System expansion or upgrades for capacity	$32,435,392	$66,773,761	$81,983,583	$36,838,974	$30,067,022
System expansion or upgrades for reliability and power quality	$38,927,621	$51,202,075	$76,168,137	$121,503,276	$84,014,971
New customer projects	$50,409,001	$51,666,269	$60,052,182	$86,128,587	$174,938,843
Grid modernization projects	$8,935	$1,665,755	$2,672,200	$3,528,966	$4,922,836
Metering	$9,068,548	$7,480,460	$7,281,770	$11,915,666	$8,613,549
Preventive maintenance	$375,740	$4,494,525	$7,754,274	$4,870,319	$2,017,798
Grand Total	**$180,379,431**	**$267,520,189**	**$321,509,097**	**$351,856,462**	**$390,113,755**

28 percent of the total. Combining these three spending lines totaled more than a billion dollars for one utility over the past five years.

If utility spending on transmission and distribution over the next five years is similar to the recent past, the total BPA and four investor-owned utilities spending could total approximately $8.8 billion. Spending by other utilities would add to this total. If additional energy efficiency, on-site solar, and peak-demand reduction programs described in this document could reduce the transmission and distribution capital costs by ten percent, it could save consumers approximately $880 million over the next five years.

The magnitude of these transmission and distribution costs and the potential for savings for consumers and the environment should convince regional energy decision makers to focus on the benefits of reducing these economic and environmental costs. The construction costs are averaged into utility rates, so consumers do not see the magnitude of the expense. The environmental costs often fall on tribal resources (such a First Foods and sacred sites), rural areas, and populations that are not represented in energy siting or ratemaking processes. Investor-owned utilities receive a rate of return on these investments; this may create an incentive to expand these facilities rather than pursue activities that reduce the need to expand these expensive assets.

As the costs of solar and wind generation declines, more of these projects will be economic to site closer to load centers on the I-5 corridor. This would reduce transmission costs and impacts.

Transmission and distribution lines have significant environmental costs. Transmission lines often damage tribal cultural and sacred sites, First Foods, and fish and wildlife habitat. Transmission lines have been linked to wildfires in the West. Distribution lines affect local communities. These issues are discussed in more detail in SECTION 3, and APPENDICES F, G, and H.

BPA, utilities, utility regulatory, commissions, energy siting agencies, and the NPCC should consider these cost and other environmental, cultural, and tribal resources in evaluating the cost effectiveness of alternatives that reduce the need for these lines.

E.1.D. Some Utilities Have Made Progress on Peak Loads

McCollough Research has analyzed actual peak loads for PacifiCorp, PGE, Puget, and Avista. The analysis shows these utilities have experienced flat or declining winter peak loads. Summer peak loads have increased mildly.

FIGURE 28 is broken into summer **(FIGURE 29)** and winter **(FIGURE 30)**.

FIGURE 28. IOU Peak Loads By Month, 2011–2021

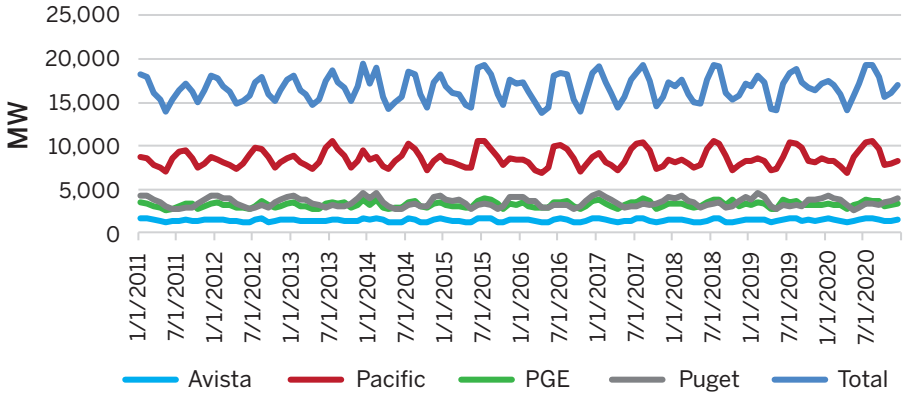


FIGURE 29. Summer Peaks By Month

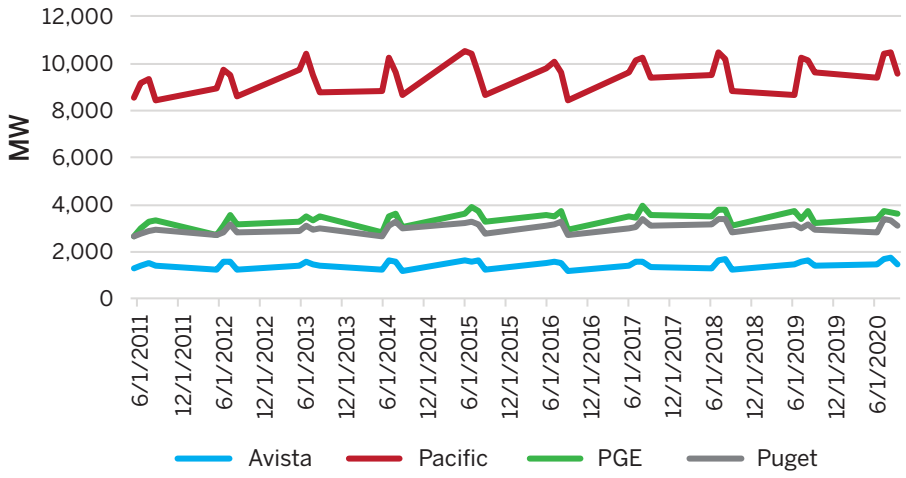
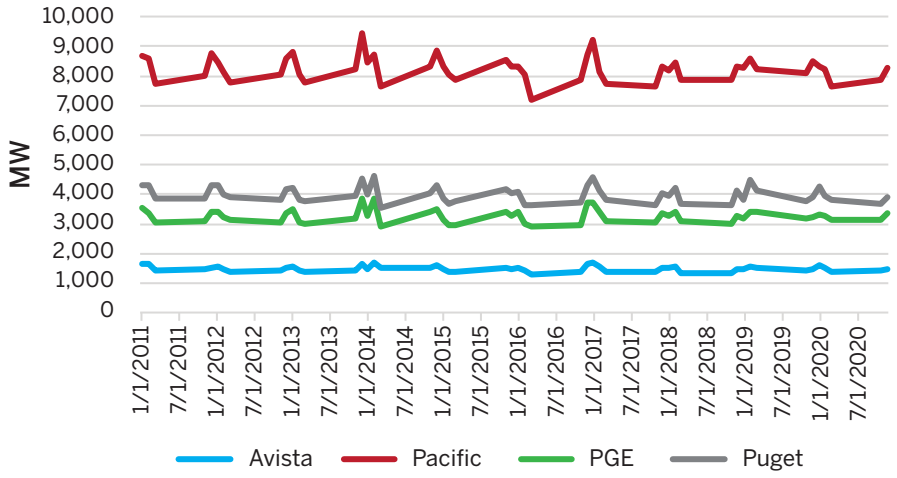


FIGURE 30. Winter Peaks By Month



E.2
The Costs of Serving Hourly and Seasonal Peak Loads

The hydroelectric system is used to serve peak loads because output from dams can be increased and decreased instantaneously by increasing or decreasing the amount of water going through the turbines.

In the Columbia River hydropower system, as is customary in most power systems, transmission and distribution lines were built to serve the highest peak load (the maximum amount of electric energy required during certain periods of time). Peak usage occurs infrequently and for short periods of time. Yet more than 25% of all capital in place, including generation capacity, transmission, and distribution is there to serve loads that occur about 6% of the time. **FIGURE 31** and **FIGURE 32** show the infrequent occurrence of the highest peak loads.

Proponents of using the hydropower system to follow peak loads argue that it is the lowest-cost option and that the fish killed in the process are an acceptable tradeoff. However, this argument ignores many of the costs to meet peak loads. For example, average-cost pricing of transmission and distribution systems obscures the true costs because all loads pay the same price for transmission and distribution, regardless of whether the transmission and distribution system is partially or fully loaded at time of use. Serving peak loads from any central station, distant plant (including hydropower) is expensive; it is far more expensive than other similarly reliable ways to meet peak loads.

FIGURE 31. Hourly Loads as a Percentage of Peak

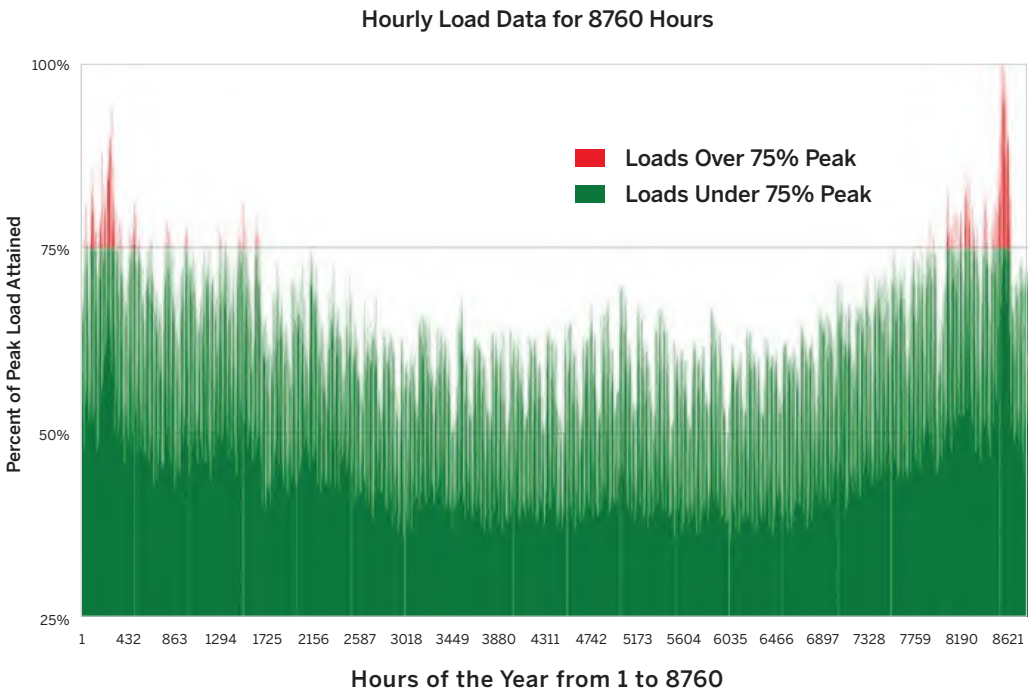
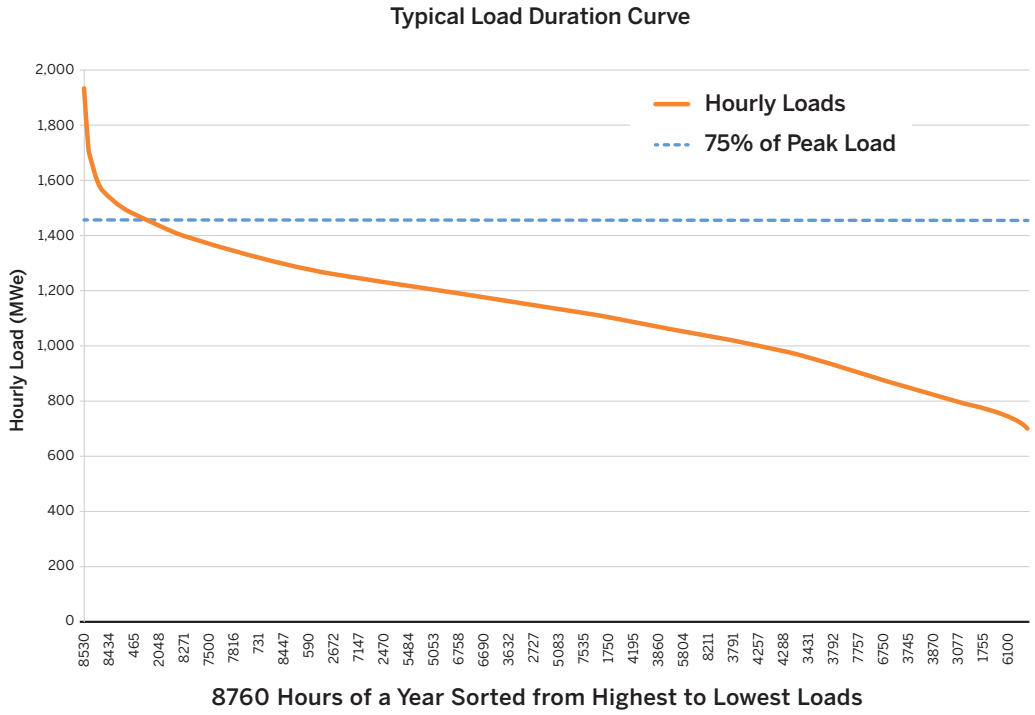


FIGURE 32. Hourly Load Duration Curve



Consider **FIGURE 32**, which contains a load duration curve for a typical northwest utility. The load duration curve is a simple structure that plots peak loads for each of the 8,760 hours in a year.[174] The loads, shown along the vertical axis, are sorted from highest to lowest-load hour; shown along the horizontal axis, the hour with the highest load is at the left of the horizontal axis and the hour with the lowest load is at the right of the horizontal axis. An arbitrary line has been drawn horizontally at 75% of the highest peak hourly load. To serve power needs in a conventional power system, a utility has to build or contract for transmission to serve its highest load, and it also must have an adequate distribution system to meet that peak load. An average rate for transmission in this region is $31 per kilowatt per year and the average distribution cost is $26 per kilowatt year.[175] That is, if a utility needs to transmit a kilowatt from a generator to load, it pays $31 per year, regardless of how many hours the kilowatt is transmitted. If transmitted for only one hour, the cost is $24 to $30 per kilowatt-hour!

Distribution costs are estimated to be three times transmission costs. Thus, the total cost of transmission and distribution can range from $80-$120 per kilowatt per year. Given this information, consider the line in **FIGURE 32** at 75% of peak load. Loads at this level and above occur about 600 hours per year. If the cost of transmission and distribution to simply deliver energy to that portion of load at 75% of peak is $80–$120; the per-kilowatt cost is

[174] For purposes of understanding, a sample load duration curve is derived in the Appendix.

[175] Northwest Power and Conservation Council memorandum *Updated Transmission and Distribution Deferral Value for the 2021 Power Plan,* March 5, 2019.

13 to 20 cents![176] The peak hour of the year (1 hour at 100% of peak—the extreme left edge of the graph) has a delivery cost of $80–$120 per kWh![177]

TABLE 12 shows the delivery costs per kWh for other loads that occur in the range of one to 600 hours per year. For example, loads at 85% of peak or higher, occur only 101 hours in a year, at a delivery cost of $.79 to $1.18 per kilowatt-hour.[178]

TABLE 12. Costs of Transmission and Distribution to Serve Infrequent Loads

Number of Hours	Percentage of Peak Yearly Load	Range of Transmission and Distribution Costs	
		$80/kWh	$120/kWh
1	100	$80.00	$120.00
21	95	$3.81	$5.71
43	90	$1.86	$2.79
101	85	$0.79	$1.19
209	80	$0.38	$0.57
600	75	$0.13	$0.20

The book value of transmission in the region is roughly $10 billion.[179] Thus, over $2.5 billion (25% of $10 billion) worth of transmission is being employed less than 6% of the time. Using the 3 to 1 ratio of distribution investments to transmission investments we used above, this means that over $7.5 billion worth of distribution is being used less than 6% of the time. Or, in sum, over $10 billion worth of capital invested in transmission and distribution sits idle for over 8100 hours per year.

Serving peak loads (*e.g.*, those above 75% of peak load) with any resource is extremely costly to the power system and serving peak with hydroelectric power is devastating to salmonids and the aquatic environment on which salmon and other species depend. Even without considering the huge costs imposed on fish and wildlife from raising and lowering river levels to serve peak loads, alternative means of serving these loads are cheaper than buying power and transmitting it from distant generators.

It is important to note that the current transmission and distribution costs are embedded costs—reductions in peak loads will not make them go away. However, reductions in peak loads may allow the current system to defer or eliminate future expansions. For example, BPA plans to spend $730 million to expand its transmission system over the next five years. These avoided costs should be considered in evaluating the cost effectiveness of energy efficiency, demand response, and other actions to reduce peak demand.

There are a number of benefits associated with controlling demand at peak. For the electrical system, lower demand on peaks translates into fewer capital resources that are needed to serve

[176] $80-$120 kW/year divided by 600 hours per year equals 13–20 cents.

[177] Some will argue that T&D costs are sunk (the capital cost has been made and cannot be recovered) and the variable cost of more throughput (*e.g.*, more power sold) is zero. There are two reasons why this is not the case. First, in the short term for non-transmission owning utilities, transmission costs are not sunk; they simply "rent" space on the lines. Second, in the long term, all T&D owners have planned expenditures at some time in the future. The planned expenditures have not been occurred, and delaying them, perhaps indefinitely, is worth a lot of money.

[178] Note that these costs do not include the cost of energy, which has been over $1,000 per megawatt hour on peak as recently ago as 2001. Costs have come down dramatically since then to a range of $30–$50 per megawatt hour

[179] The book value of BPA's transmission is about $5.5 billion (BPA Annual Reports), up from about $4.5 billion in 2001. Avista, Idaho Power Company, Montana Power Company, PacifiCorp, and Puget Energy Services combined had about $3.8 billion of book value in their transmission systems in 2001 (See FERC Form 1 data for 2000.) In 2003, we estimated that other utilities in the region not under FERC's jurisdiction make up another $.15 billion to get us to our estimate of $8.5 billion. Adding the additional $1 billion of BPA investment to the estimate used in the 2003 *Energy Vision* would total $9.5 billion. Other utilities have made investments also. Because the analysis here is only used to show the order of magnitude of transmission costs on partially filled lines, we have rounded up to $10 billion, to reflect other investments that have been made.

loads. The grid can serve the same total energy needs with fewer generating plants and a smaller investment in transmission and distribution lines over time if peaks are lowered. Line losses and ancillary services can be reduced with lower demand, as well.

Importantly, lower peak demands also help fish in the river. The river is ramped up and down to follow peak loads, and in so doing, smolts (juvenile fish) have been stranded on banks along the river, and redds (where salmon lay their eggs) have been dried out. Reducing peak loads will limit the number of hours in a year when the rivers have to be ramped up to meet peak demand, thereby, saving fish.

Looking forward, as we acquire the general ability to control loads, we can envision a time when loads can be shaped at all times to allow appropriate levels of spill and flow for fish migration through the river system. And, we should be able to get to this point at costs that are considerably less to the power system than in the past.

The Lawrence Berkeley National Laboratory has prepared a report entitled: *Grid-Interactive Efficient Buildings: An Introduction for State and Local Governments*[180] which describes grid-interactive efficient buildings, highlights trends, challenges, and opportunities for demand flexibility; provides an overview of valuation and performance assessments for demand flexibility; and outlines actions that state and local governments can take, in concert with utilities, regional grid operators, and building owners, to advance demand flexibility. This report also provides a sense of the potential for DERs coupled with controls to offset the need for conventional generation, transmission and distribution system solutions to meeting loads.

E.2.1 Capital Cost Savings Identified

Suppose future peak loads could be lowered, for example to 75% of current peak load[181]. These loads would not have to be eliminated overnight because the transmission system, albeit stressed, has and can continue to serve regional loads at today's levels. Peak loads could be reduced on the transmission system gradually by using the resource options described below. The peak load reduction could be designed to avoid planned transmission investment upgrades that are being driven by the need to serve growing peak loads. This schedule would allow the region to ensure that these actions are carefully planned and implemented correctly.[182]

With peaks at 75% of today's peaks, the capital earmarked for new transmission and distribution upgrades to serve peak load growth could be available to invest in alternative technologies to serve peak loads. The savings would be committed to load management, conservation, clean distributed generators to serve those loads, utility scale batteries, solar rooftop systems with batteries, and resources sited strategically within the transmission and distribution system. These energy plants and strategies would be used to serve peak loads and to serve off-peak loads whenever market prices exceeded the variable costs of operating the specific plants and implementing the load management strategies.

The magnitude of planned transmission and distribution investments that could be

[180] https://emp.lbl.gov/publications/grid-interactive-efficient-buildings

[181] In keeping with the theme of this report, this is not a prediction of what might happen soon, but rather a vision of what could be done with a regional focus.

[182] This is the goal of BPA as it revamps its transmission planning function, using the Round Table as an advisory group. The Round Table did not meet for several years, but reconvened in April 2011.

eliminated or delayed is significant. As previously mentioned, a rough estimate of the book value of transmission used to serve regional load is about $10 billion. Because the book value has been depreciated and was funded by low-cost government debt for the most part, the replacement cost of the transmission system would be much higher. In the 2003 *Energy Vision for the Columbia River* we assumed it would be $17 billion dollars. An inflation rate of 2% over the last 10 years would bring replacement value to about $20 billion.

Since the region's transmission system is now constrained during many hours, new investment will be needed to serve loads if load shapes do not change. The region would need to invest about 1% of the total value of the system per year to keep up with load growth.[183] Thus, about $200 million per year will have to be invested in transmission to serve peak load growth.[184]

Book value and replacement value of distribution systems in the region has been estimated at roughly three times that of transmission. Many of the actions we include in our plan will also save distribution investments. Distribution investments are also often very costly from a social perspective because they may entail digging up city streets. Large capital costs are incurred along with social costs and economic losses associated with time lost in traffic jams and other even greater displacements.[185] The savings from deferring investments would be great and would allow for even more generation to be built, if necessary. If the region were to do away with transmission investments to meet load growth, it could also do away with the corresponding investment in distribution systems. Thus, an additional $600 million savings per year (three times that of transmission) could be realized through forgone investment in distribution.

E.2.2 Energy Costs

Historically, energy costs have fluctuated widely. In 2001, not long before we published the initial draft of the Energy Vision, prices in the Northwest spiked to as high as $1,000 per megawatt hour ($10 per kilowatt hour). In the spring of 2001, futures for summer power were selling for 50 cents/kWh. Utilities and BPA were buying power at 20–50 cents per kilowatt hour and selling power to end users at less than 2.5 cents per kilowatt hour. That reality left BPA with an acute financial problem, which had implications for the protection of fish and wildlife.

The risk of fluctuating prices still exists from a range of catalysts, such as disruptions in power production or the transmission system. The 2013 *Energy Vision for the Columbia River* has been designed with the recognition that we cannot predict future price excursions, and that prices could spike again; however, the recommendations in this report should help constrain future price volatility.

[183] Based on an assumption of a 2% growth in peak loads. BPA had scheduled over $2 billion between 2002 and 2006. Only about $1 billion of that amount appears to have been spent.

[184] Of course, there will also be capital investment to maintain existing wires. This will be true for the distribution system also. That investment is separate from the investments to serve new load growth and generation interconnections addressed here.

[185] Reduced access to commercial ventures is an example.

E.2.3 Transmission and Distribution Costs

Transmission and distribution costs have several components.[186] One is the capital cost of the installations, and a second is the cost imposed by congestion on the grid. At many times of the day, season, and year, constraints exist on parts of the transmission and distribution system. Historically, BPA and other utilities have dispatched resources to move power around these constraints. The costs of doing this have been melded into average costs that in turn have been included in an average total power cost. The value of the resources used to get around transmission constraints is not transparent.

The end user has not paid the true cost of using either the transmission or distribution systems. As we noted previously, the cost of transmission and distribution to serve peak loads is enormous, but these costs are spread over all utility customers and all hours of the year. If the true costs of transmission capital and congestion were charged to end users, much of the crisis experienced in 2001 would have been averted because peak loads would have been lowered.[187] From an economic perspective, too much transmission is built to serve peak loads that are greater than they would have been if users paid the true price of the delivered peak power.

Today there are still calls for more transmission construction.[188] If one assumes that the trend toward deregulated markets continues, investors who build additional transmission will be at risk. Higher prices for energy and delivery at peak would drive users to look for other innovative ways to serve their peak loads, including shifting those loads to off-peak times when the prices of energy and delivery are lower. The advent of Smart Grid technologies and strategies that will enable devices behind customers' meters to compete with generation and transmission will exacerbate this movement. If this occurs, which we think it will, much of that new investment could easily be stranded.

The Lawrence Berkeley National Laboratory has also prepared a report entitled: *Determining Utility System Value of Demand Flexibility from Grid-Interactive Efficient Buildings.*[189] This report describes how current methods and practices that establish value to the electric utility system of investments in energy efficiency and other distributed energy resources (DERs) including demand response measures that reduce generation costs, and/or reduce delivery (transmission and distribution) costs can be enhanced to more accurately determine the value of grid services they provide. It contains seven recommendations for improving the methods used by utilities (and others) to determine the "avoided cost" of grid services so that DERs are fairly valued compared to conventional generation, transmission and distribution alternatives.

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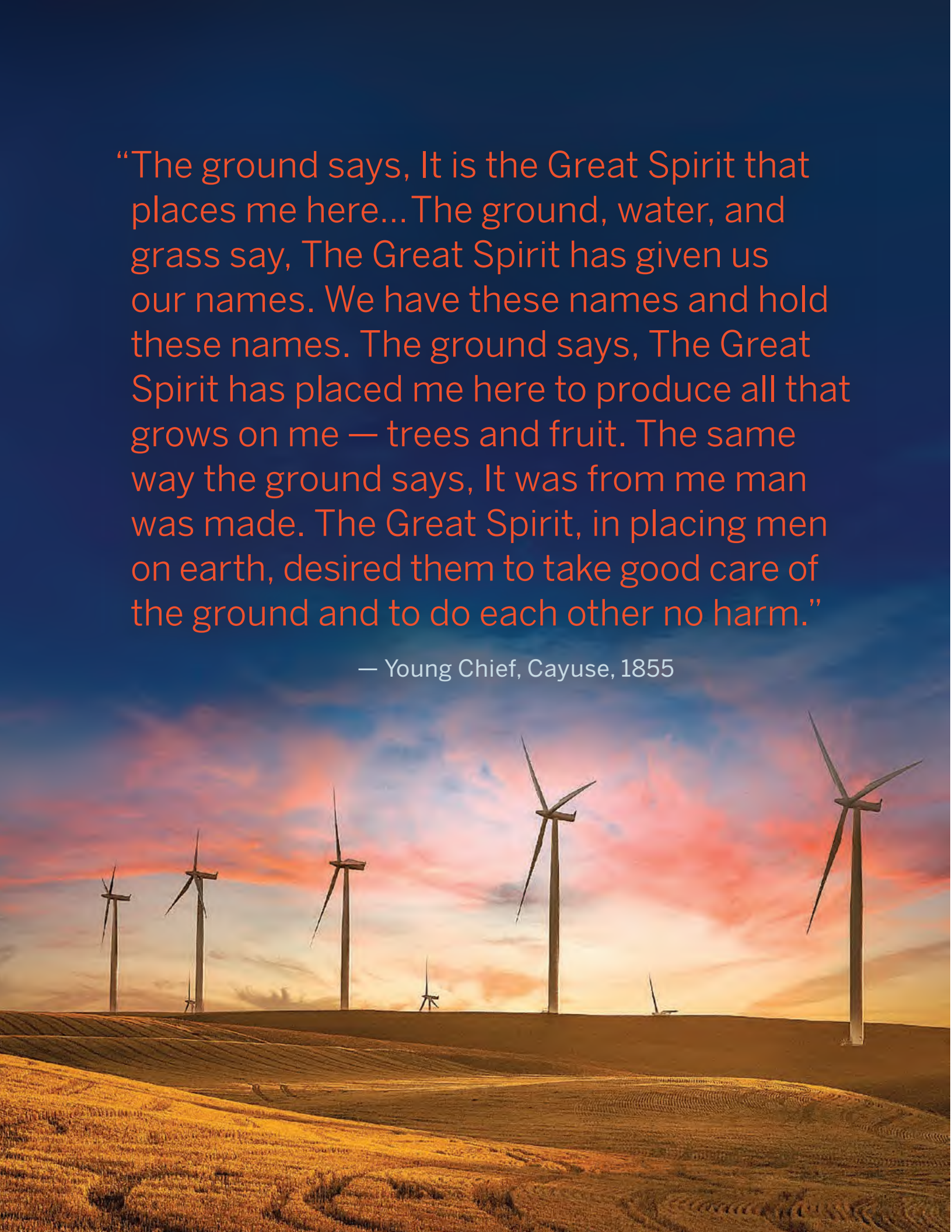
[186] Here we ignore line losses associated with T&D.

[187] Prices shot up because during peak loads generation was not always available to meet loads. This had the effect not only of increasing prices, but also led to rolling brown outs in parts of the West.

[188] BPA's book value of transmission was $5.5B in 2013 versus $4.5 in 2001.

[189] https://emp.lbl.gov/publications/determining-utility-system-value.



"The ground says, It is the Great Spirit that places me here... The ground, water, and grass say, The Great Spirit has given us our names. We have these names and hold these names. The ground says, The Great Spirit has placed me here to produce all that grows on me — trees and fruit. The same way the ground says, It was from me man was made. The Great Spirit, in placing men on earth, desired them to take good care of the ground and to do each other no harm."

— Young Chief, Cayuse, 1855

APPENDIX F:

Sample Criteria for Siting Renewable Resources

Introduction

SECTION 3.4 of the Energy Vision identifies criteria to address tribal resources in the Pacific Northwest. This appendix provides examples of other criteria that were identified by the Department of the Interior for the southwest

In October 2012, the Department of the Interior completed such a plan for development of solar energy on public lands in six western states. The Programmatic Environmental Impact Statement (PEIS) for solar energy development provides a blueprint for utility-scale solar energy permitting in Arizona, California, Colorado, Nevada, New Mexico and Utah by establishing solar energy zones with access to existing or planned transmission, incentives for development within those zones, and a process through which to consider additional zones and solar projects.

The Solar PEIS establishes an initial set of 17 Solar Energy Zones (SEZs), totaling about 285,000 acres of public lands, that will serve as priority areas for commercial-scale solar development, with the potential for additional zones through ongoing and future regional planning processes. If fully built out, projects in the designated areas could produce as much as 23,700 megawatts of solar energy, enough to power approximately 7 million American homes. The program also includes a framework for regional mitigation plans, and to protect key natural and cultural resources the program excludes approximately 79 million acres that would be inappropriate for solar development based on currently available information.

In January of 2013, the Department of the Interior completed a plan for renewable resource development in Arizona. The Restoration Design Energy Project (RDEP) is an initiative to identify lands that may be suitable for the development of renewable energy. The RDEP Record of Decision and Approved Resource Management Plan Amendments establish 192,100 acres of renewable energy development areas on BLM land throughout Arizona. These areas are near transmission lines or designated corridors, close to population centers or industrial areas, and in areas where impacts on water usage would be moderate. These lands also have few known resource impacts or have been previously disturbed, such as retired agriculture properties. These areas are available for solar or wind energy development. In addition, the Plan establishes the Agua Caliente Solar Energy Zone on 2,550 acres in western Arizona.

Sample Criteria for Siting Renewable Resources

The BLM PEIS for solar development had some similar criteria for solar development in the desert SW. These criteria (listed on the following pages) were developed to address the potentially affected interests in the desert Southwest. Some of them may be suited to the Columbia Basin.

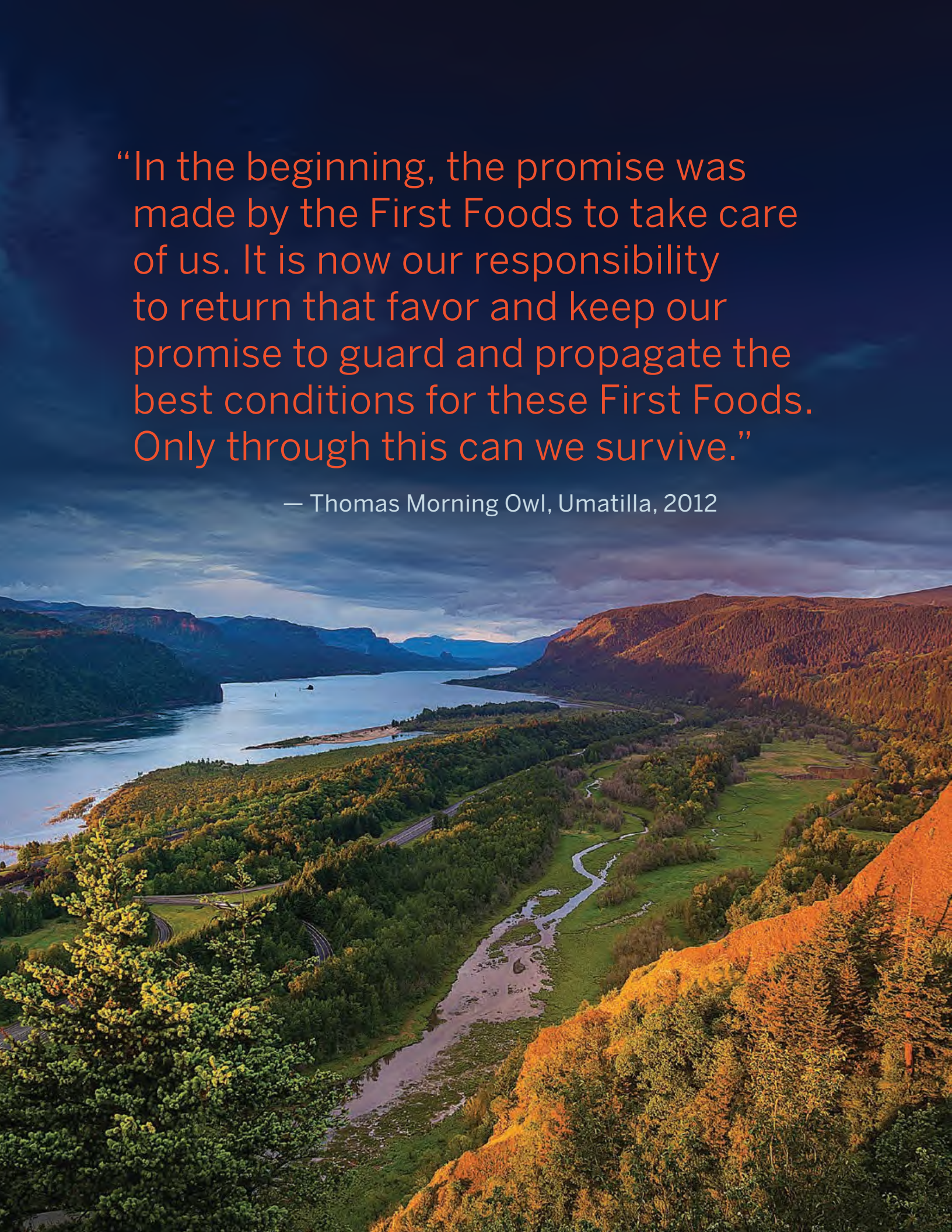
Exclusions under BLM's Solar Energy Development Program Alternative[190]

1. Lands with slopes greater than 5% determined through geographical information system (GIS) analysis using digital elevation models.
2. Lands with solar insolation levels less than 6.5 kWh/m^2/day determined through National Renewable Energy Laboratory solar radiation GIS data (http://www.nrel.gov/rredc/solar_data.html).
3. All Areas of Critical Environmental Concern (ACECs) identified in applicable land use plans (including Desert Wildlife Management Areas [DWMAs] in the California Desert District planning area).
4. All designated and proposed critical habitat areas for species protected under the Endangered Species Act (ESA) of 1973 (as amended) as identified in respective recovery plans (http://ecos.fws.gov/tess_public/TESSWebpageRecovery?sort=1).
5. All areas for which an applicable land use plan establishes protection for lands with wilderness characteristics.
6. Developed recreational facilities, special-use permit recreation sites (*e.g.*, ski resorts and camps), and all Special Recreation Management Areas (SRMAs) identified in applicable land use plans, except for those in the State of Nevada and a portion of the Yuma East SRMA in Arizona.
7. All areas where the BLM has made a commitment to state agency partners and other entities to manage sensitive species habitat, including but not limited to sage-grouse core areas, nesting habitat, and winter habitat; Mohave ground squirrel habitat; flat-tailed horned lizard habitat; and fringe-toed lizard habitat.
8. Greater sage-grouse habitat (currently occupied, brooding, and winter habitat) as identified by the BLM in California, Nevada, and Utah, and Gunnison's sage-grouse habitat (currently occupied, brooding, and winter habitat) as identified by the BLM in Utah.
9. All areas designated as no surface occupancy (NSO) in applicable land use plans
10. All right-of-way (ROW) exclusion areas identified in applicable land use plans.
11. All ROW avoidance areas identified in applicable land use plans.
12. In California, lands classified as Class C in the California Desert Conservation Area (CDCA) planning area.
13. In California and Nevada, lands in the Ivanpah Valley.
14. In Nevada, lands in Coal Valley and Garden Valley.
15. All Desert Tortoise translocation sites identified in applicable land use plans, project-level mitigation plans or Biological Opinions.
16. All Big Game Migratory Corridors identified in applicable land use plans.
17. 1ll Big Game Winter Ranges identified in applicable land use plans.
18. Research Natural Areas identified in applicable land use plans.
19. Lands classified as Visual Resource Management (VRM) Class I or II (and, in Utah, Class III) in applicable land use plans.
20. Secretarially designated National Recreation, Water, or Side and Connecting Trails and National Back Country Byways (BLM State Director approved) identified in applicable

[190] https://solareis.anl.gov/documents/fpeis/Solar_FPEIS_Volume_1.pdf#page=46

BLM and local land use plans (available at http://www.americantrails.org/NRTDatabase), including any associated corridor or lands identified for protection through an applicable land use plan.

21. All units of the BLM National Landscape Conservation System, congressionally designated National Scenic and Historic Trails (National Trails System Act [NTSA], P.L. 90-543, as amended), and trails recommended as suitable for designation through a congressionally authorized National Trail Feasibility Study, or such qualifying trails identified as additional routes in law (*e.g.*, West Fork of the Old Spanish National Historic Trail), including any trail management corridors identified for protection through an applicable land use plan. Trails undergoing a congressionally authorized National Trail Feasibility Study will also be excluded pending the outcome of the study.
22. National Historic and Natural Landmarks identified in applicable land use plans, including any associated lands identified for protection through an applicable land use plan.
23. Lands within the boundaries of properties listed in the National Register of Historic Places (NRHP) and any additional lands outside the designated boundaries identified for protection through an applicable land use plan.
24. Traditional cultural properties and Native American sacred sites as identified through consultation with tribes and recognized by the BLM.
25. Wild, Scenic, and Recreational Rivers designated by Congress, including any associated corridor or lands identified for protection through an applicable river corridor plan.
26. Segments of rivers determined to be eligible or suitable for Wild or Scenic River status identified in applicable land use plans, including any associated corridor or lands identified for protection through an applicable land use plan.
27. Old Growth Forest identified in applicable land use plans.
28. Lands within a solar energy development application area found to be inappropriate for solar energy development through an environmental review process that occurred prior to finalization of the Draft Solar PEIS.
29. Lands previously proposed for inclusion in SEZs that were determined to be inappropriate for development through the NEPA process for the Solar PEIS (limited to parts of the Brenda SEZ in Arizona; the previously proposed Iron Mountain SEZ area and parts of the Pisgah and Riverside East SEZs in California; parts of the De Tilla Gulch, Fourmile East, and Los Mogotes East SEZs in Colorado; and parts of the Amargosa Valley SEZ in Nevada).
30. In California, all lands within the proposed Mojave Trails National Monument and all conservation lands acquired outside of the proposed Monument through donations or use of Land and Water Conservation Funds.
31. In California, BLM-administered lands proposed for transfer to the National Park Service with the concurrence of the BLM.
32. Specific areas identified since the publication of the Supplement to the Draft Solar PEIS by the BLM based on continued consultation with cooperating agencies and tribes to protect sensitive natural, visual, and cultural resources (total of 1,066,497 acres [4,316 km^2]. Note there are some overlapping exclusions). Data and finer scale maps will be made available through the Solar PEIS project Web site (http://solareis.anl.gov). Note that in some cases, the description of these areas will be withheld from the public to ensure protection of the resource.


“In the beginning, the promise was made by the First Foods to take care of us. It is now our responsibility to return that favor and keep our promise to guard and propagate the best conditions for these First Foods. Only through this can we survive.”
— Thomas Morning Owl, Umatilla, 2012

APPENDIX G:

Tribal Cultural Resources

In the past, non-Indian archaeologists had control of how tribal cultural resources were managed on tribal, federal, state, and private lands. Management decisions, often based on values other than protection of the resources, resulted in the destruction of sites important to tribes. The CRITFC member tribes each have cultural resources programs established to protect these important tribal resources.[191]

For instance, the cultural resources program of the Nez Perce Tribe has the following mission:

> *The mission of the Cultural Resource Program (CRP) is to promote the understanding and use of nimíipuu'neewit (traditional Nez Perce life-ways) as integral components of Tribal culture and regional management. The CRP fulfills its programmatic purpose by:*
>
> - *Assisting Tribal Leadership in treaty rights protection,*
> - *Documenting traditional and ancestral knowledge,*
> - *Integrating **nimíipuutimpt** within our Tribal community and infrastructure, and*
> - *Protecting sites, landscapes, and associated knowledge integral to the perpetuation of **nimíipu'neewit** through meaningful consultation*
> - *The Cultural Resource Program consists of 4 major areas that work to fulfill these goals: Archaeology/Tribal Historic Preservation Office (THPO), Ethnography, NAGPRA, Language, and Hanford Cultural.*

The following sections of this appendix provide a brief overview of tribal viewpoints concerning cultural resources and how they are recognized and valued.

Differences Between Tribal and Non-Tribal Viewpoints Concerning Cultural Resources

This holistic, interconnected view of the world and all the resources in it is sometimes hard for nonnative people to understand. It is from the view that the Nez Perce interpretation of cultural resources arises. Federal and State legislation is designed to protect "Historic Properties". Historic properties are narrowly defined in federal law as "any prehistoric or historic district, site, building, structure, or object included in, or eligible for inclusion on the National Register including artifacts, records, and material remains related to such a property or resource". This definition differs greatly from the holistic belief of the tribes that water, air, animals, soil, rock, fish, birds along with those items included in the Federal definition should be considered

[191] https://www.nezpercecultural.org/what-we-do; https://ctuir.org/departments/natural-resources/cultural-resources-protection/ https://warmsprings-nsn.gov/program/cultural-resources/; https://www.yakama.com/programs/

cultural resources. While many of these items in themselves may not be adequately considered historic properties by narrow interpretations of federal law, they certainly contribute to the reasons that individual locations or items can be considered historic properties. They often provide the contextual link to the landform and the overall tribal cultural environment, which is vital to understanding a property's significance.

This context often divides the native and nonnative view of cultural resource protection. Tribal people believe that this holistic viewpoint is extremely important when addressing cultural resources. In fact, this was so important that the tribes protected key cultural activities such as fishing, hunting, and gathering in the treaties of 1855. This context is especially significant when dealing with the prehistoric cultural manifestations remaining on the landscape within the tribal traditional area.

It bears repeating that Tribes look at cultural resources differently than archaeologists do. Most generally, the tribes note that a cultural resource is any place that is valued by a tribe because of some sort of association with the tribe's ancestors. The tribes also point out that cultural resources can be either places or practices. The practices are centered around people's actions which may or may not require a special place. It is the 'action' that is special to the cultural tradition or lifeway. The places are physical locations on the land that are important because something special is done there (vision questing, medicine gathering), because special things are located there (important plants, herbs, animals), because people did something there in the past (lived, buried the dead, etc.), or because they are associated with traditions (origin places, etc.). These places are generally considered under the archaeologist's term "site" or "Traditional Cultural Property" (TCP).

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Another important point is that cultural resources may be places where plants, animals, or minerals are found that are needed to maintain the ways of life passed down from the ancestors. Cultural resources significant to the tribes world-view include such things as the Indian people themselves, their communities, and their way of life; native elders with their unique information regarding their personal histories as well as tribal histories; clean air; clean water where salmon and other fish, eels, and other riverine resources so highly prized by the tribes for their traditional subsistence live; the root grounds providing a multitude of edible roots traditional to their dietary needs; and the berry patches, especially huckleberries.

Clearly, a crucial cultural resource for the Columbia River treaty tribes as well as other Northwest tribes, is the salmon. Many of the archaeological sites along the Columbia and Snake rivers show evidence of the antiquity of the relationship between tribal members and these fish. Should this relationship be broken by the extinction of the salmon, the loss to the tribes' culture would be immeasurable.

Cultural Dimensions of Socioecological Systems

The following analysis and the italicized language is adapted from: *Cultural Dimensions of Socioecological Systems: Key Connections and Guiding Principles for Conservation in Coastal Environments*, Melissa R. Poe, Karma C. Norman, & Phillip S. Levin. 2013 NOAA Fisheries, Northwest Fisheries Science Center, 2725 Montlake Blvd East, Seattle, WA 98112-2097, USA. This report describes five categories of sociocultural values. Following each italicized bullet is an expression of the cultural context in from a tribal viewpoint.

1. **Cultural connections to ecosystems are rooted in meanings, *values, and identity*. Cultural ecosystem meanings and values are deeply rooted and define a person or community; they are implicit in senses of place and often form the basis of community, individual, and professional identities.**

TRIBAL CONTEXT:

There is so much to this word or this way, this Tamanwit. It's how we live. It's our lifestyle. There is so much that we as Indian people are governed by, through our traditions, our culture, our religion, and most of all, by this land that we live on. We know through our oral histories, our religion, and our traditions how time began. We know the order of the food, when this world was created, and when those foods were created for us. We know of a time when the animals and foods could speak. Each of those foods spoke a promise. They spoke a law—how they would take care of the Indian people and the time of year when they would come. All of those foods got themselves ready for us—our Indian people who lived by the land. It was the land that made our lifestyle. The foods first directed our life. Today, we all have these traditions and customs that recognize our food: our first kill, first fish, first digging, the first picking of berries. All of those things are dictated to us because it was shown and it directed our ancestors before us.[192]

[192] CTUIR Comprehensive Plan, 2010. https://ctuir.org/system/files/FinalCompPlan/pdf (quoting Armand Minthorn, *As Days Go By*, 2006).

2. Cultural dimensions of ecosystems are embedded in *local ecological knowledge* (LEK) and practice. Local knowledge is not simply "passed down" through generations *per se*, but continually regenerated through practical engagements with ecosystem components, articulated through language, local meanings, methods, and cultural practices and frameworks.

TRIBAL CONTEXT:

When we were created we were given our ground to live on, and from that time these were our rights. This is all true. We had the fish before the missionaries came....This was the food on which we lived.... My strength is from the fish; my blood is from the fish, from the roots and the berries. The fish and the game are the essence of my life.... We never thought we would be troubled about these things, and I tell my people, and I believe it, it is not wrong for us to get this food. Whenever the seasons open, I raise my heart in thanks to the Creator for his bounty that this food has come.[193]

3. *Informal economics* must be considered in addressing negative impacts to tribal fisheries. Subsistence fishing and harvesting, for example, is a practice often motivated by food provisioning rather than catching or processing species for sale and income generation. Subsistence fishing includes personal or family-level consumption to meet or supplement household food needs, or procurement for others distributed through sharing, gifting, and bartering. Subsistence feeds bodily and spiritual nourishment and is linked to culture, LEK, social relations, and food traditions.

TRIBAL CONTEXT:

When God created Indians on the Earth, he gave us everything. Main thing was salmon and meat. And all the vegetables—the potatoes, celery—everything, you name it, that's what he gave to us. And that's what we were raised on.[194]

4. *Resource management and governance* institutions shape and are shaped by cultural dimensions of ecosystems. Mechanisms such as harvest controls (*e.g.*, timing, location, species, quantities, and techniques), formal and customary rules of access to resources, and decision-making processes constitute governance.

TRIBAL CONTEXT:

In addition, the Treaty of 1855 does not expressly state that the Yakima Nation relinquished its jurisdiction over matters pertaining to fishing rights. As the treaty constitutes a grant of rights from the Indians to the Government, Winans, supra, 198 U.S. at 381, 25 S.Ct. 662, 49 L.Ed. 1089, any rights not granted must be considered retained by the Tribe. Here, the Indians qualified their fishing right only to the extent of permitting citizens of the territory to fish 'in common' with them at 'usual and accustomed fishing

[193] Testimony of George Meninock before the Washington Supreme Court in 1913 at page 146 in Meyer Resources, Inc., "Tribal Circumstances and Impacts of the Lower Snake River Project on Nez Perce, Yakama, Umatilla, Warm Springs and Shoshone Bannock Tribes", April 1999 https://www.critfc.org/wp-content/uploads/2014/11/circum.pdf [hereinafter *Meyer Report*]

[194] *Meyer Report* at 374.

places' off the reservation. Given this fact and the vital role of fishing in the Yakima culture, we conclude that the Yakima Nation did reserve the authority to regulate Tribal fishing at 'all usual and accustomed places', whether on or off the reservation.[195]

5. *Sociocultural health* and ecosystem health are integrated. For a human community that is culturally attached to salmon changes to the trophic structure (or food web) within which salmon is embedded will have specific implications for cultural wellbeing in ways that aggregated ecological integrity measures may not reveal.

TRIBAL CONTEXT:

Traditional activities such as fishing, hunting, and gathering roots, berries and medicinal plants build self-esteem for Nez Perce peoples—and this has the capacity to reduce the level of death by accident, violence and suicide affecting our people. When you engage in cultural activities you build pride. You are helped to understand "what it is to be a Nez Perce"—as opposed to trying to be someone who is not a Nez Perce. In this way, the salmon, the game, the roots, the berries and the plants are the pillars of our world.

— Leroy Seth, Nez Perce Elder[196]

In sum, there's a huge connection between salmon and tribal health. Restoring salmon restores a way of life. It restores physical activity. It restores mental health. It improves nutrition and thus restores physical health. It restores a traditional food source, which we know isn't everything—but it's a big deal. It allows families to share time together and builds connections between family members. It passes on traditions that are being lost. If the salmon come back, these positive changes would start.

— Chris Walsh, Yakama Psycho-Social Nursing Specialist[197]

Conclusion

As can be seen from the foregoing, tribal cultural resources are broader in scope than the archeological resource focus that flows from federal laws such as the National Historic Preservation Act or the protection of human remains that is required by the Native America Graves Protection Act. Tribal cultural resources are sometimes thought of as the tangible representations of tribal history and culture that are a reminder of who tribal people are, where they came from and historic values.

[195] *Settler v. Lameer,* 507 F.2d 231, 237 (9th Cir. 1974)

[196] *Meyer Report* at 5.

[197] *Meyer Report* at 5-6.

"Our relationship to salmon and the First Foods is sacred and reciprocal. The First Foods nourish us and we protect them and the habitats that support them."

—Jeremy Takala. Yakama, 2022

APPENDIX H:

First Foods Appendix

Aligning environmental management with ecosystem resilience: a First Foods example from the Confederated Tribes of the Umatilla Indian Reservation, Oregon, USA

Quaempts, E. J., K. L. Jones, S. J. O'Daniel, T. J. Beechie, and G. C. Poole. 2018.

ABSTRACT

The concept of "reciprocity" between humans and other biota arises from the creation belief of the Confederated Tribes of the Umatilla Indian Reservation (CTUIR). The concept acknowledges a moral and practical obligation for humans and biota to care for and sustain one another, and arises from human gratitude and reverence for the contributions and sacrifices made by other biota to sustain human kind. Reciprocity has become a powerful organizing principle for the CTUIR Department of Natural Resources, fostering continuity across the actions and policies of environmental management programs at the CTUIR. Moreover, reciprocity is the foundation of the CTUIR "First Foods" management approach. We describe the cultural significance of First Foods, the First Foods management approach, a resulting management vision for resilient and functional river ecosystems, and subsequent shifts in management goals and planning among tribal environmental staff during the first decade of managing for First Foods. In presenting this management approach, we highlight how reciprocity has helped align human values and management goals with ecosystem resilience, yielding management decisions that benefit individuals and communities, indigenous and nonindigenous, as well as human and nonhuman. We further describe the broader applicability of reciprocity-based approaches to natural resource management.

Find full document at:

Aligning environmental management with ecosystem resilience: a First Foods example from the Confederated Tribes of the Umatilla Indian Reservation, Oregon, USA. Ecology and Society 23(2):29. https://doi.org/10.5751/ES-10080-230229

APPENDIX I:

COLUMBIA RIVER INTER-TRIBAL FISH COMMISSION

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March 26, 2021

Frank Afranji, President
Northwest Power Pool
7505 NE Ambassador Pl, #R
Portland, OR 97220
Via email frank.afranji@nwpp.org

Dear Mr. Afranji:

We have reviewed the Conceptual Design document for the Northwest Power Pool (NWPP) Resource Adequacy (RA) program. This document describes a collaborative effort by all 17 Balancing Authorities (BAs) in the greater Pacific Northwest (PNW) area to establish a region-wide approach to address resource adequacy issues in serving the region's electricity demands.

We are writing to ensure that your process addresses important fish and wildlife protection considerations.

Background

The Columbia River Inter-Tribal Fish Commission (CRITFC) is comprised of the Yakama, Nez Perce, Umatilla, and Warm Springs tribes. These four tribes signed treaties in 1855 with the United States. Among other things, the treaties reserved the tribes' rights to take fish that pass their usual and accustomed fishing places. Numerous federal court decisions have affirmed these rights.[1] For the tribes and CRITFC to accomplish their mission, salmon and Pacific lamprey populations need to be rebuilt. The operations of the dams on the Columbia and Snake rivers continue to be a main deterrent to anadromous fish restoration.

CRITFC developed an Energy Vision for the Columbia River in 2003 to reduce the pressures of the Pacific Northwest's electricity needs on the Columbia River and its ecosystem, particularly salmon. The Vision was prepared following the West Coast energy crisis of 2001 when many salmon protection measures on the Columbia River were curtailed.

CRITFC updated the Energy Vision in 2013. That document included recommendations on reducing peak demand, increasing energy efficiency and renewable resources, strategically siting resources, and strategies to address emergency dry years. The Energy Vision noted that

[1] E.g. Sohappy v. Smith, 302 F.Supp. 899 (D.Or. 1969), aff'd, United States v. Oregon, 529 F.2d 570 (9th Cir. 1976); Washington v. Washington State Commercial Passenger Fishing Vessel Ass'n, 443 U.S. 658 (1979); United States v. Winans, 198 U.S. 371 (1905); Confederated Tribes of the Umatilla Indian Reservation v. Alexander, 440 F.Supp. 553 (D.Or. 1977).

"Appropriate planning of regional resources can provide the Northwest with a robust energy system that withstands most unknown future events and keeps costs stable, while protecting fish and wildlife."

The 2013 *Energy Vision for the Columbia River* had four goals:

1. Reduce the stress of new and changing energy demands on the Columbia River's fish and wildlife resources.

2. Lessen the demand for fossil-fuel generation that contributes to climate change.

3. Serve the energy demands of consumers more cheaply than they are served today to better capture the value of the Columbia River for the Northwest.

4. Provide increased protection for ratepayers and fish and wildlife against unanticipated events, such as those the region faced in 2001.

The day-to-day and seasonal operations of the hydroelectric system to meet peak and seasonal electricity loads cause changes in river conditions that continue to kill salmon and other important species. While changes in operations have lessened the frequency and severity of these occurrences, their effects are still significant.

Hydropower is used to serve peak loads because dams can react to demand by quickly putting more or less water through the turbines that generate electricity. Serving peak loads with hydropower kills millions of juvenile salmon every year. During certain times of the year, so much water is drawn down to generate electricity that salmon redds (gravel nests where salmon lay eggs) are uncovered or dewatered and their eggs die. Daily fluctuations change river water levels and juvenile fish that feed and live near the shore can be stranded and die when water levels are reduced. Migration of fish is interrupted when flows decrease because there is less demand for electricity and therefore less water moving through the reservoirs behind the dams. Fluctuations in reservoirs hurt resident fish by dewatering habitat and food supplies and reducing nutrients in the reservoirs.

Water held behind storage dams for power generation would, under natural conditions, be in the river aiding the swift and timely downstream migration of young salmon. Saving this water for winter and summer energy production alters the natural (or normative) river conditions that aid juvenile salmon migration and would help in the restoration of fish to harvestable levels.

A lot has changed since our work in 2013. Electricity disruptions in California, Texas, and elsewhere have increased attention on resource adequacy and grid integration issues. CRITFC is in the process of updating the Energy Vision, which we hope to complete in 2021. We have sought comments from regional energy experts on the scope of the new document and would welcome your comments. We have attached a copy of the 2013 document.

The 2021 update will focus on ways to reduce the impacts of the electricity system on fish and wildlife, including:

- Ways to reduce greenhouse gases that cause global warming;
- Appropriate siting of new technologies to help assure that tribal resources, such as first foods and cultural resources are protected;
- Integration of electricity in the western United States and Canada, including transboundary issues with Canada;
- The potential to increase the availability of energy efficiency, renewable resources, distributed resources, and smart grid technology to meet future energy needs; and
- Ways to reduce the risk of grid-caused wildfires, which have ravaged the Western States.

The Power Pool Resource Adequacy Program

Based on the Resource Adequacy Program Conceptual Design dated August 2020, we understand that you are currently in the detailed design phase of your process. We also note that the resource adequacy project will focus on capacity. The 2013 Energy Vision included a number of recommendations on reducing peak demand and addressing capacity issues. We expect this will be a major focus of our 2021 update.

We further note that the draft Resource Adequacy Program suggests that "the capacity program will not initially focus on longer time-horizon of fuel-related issues (e.g., dry water years), though we understand those issues are important." The 2013 Energy Vision included recommendations on dry-year strategy to address the kinds of problems the region has experienced in the past. We urge the Power Pool to expand its scope to include an energy resource adequacy program to address dry years that can adversely affect the northwest economy and its important natural resources, including salmon.

It is our understanding that this effort is specifically designed to address PNW 2020 - 2030 capacity shortfalls. If successful, the Northwest Power Pool Resource Adequacy program will achieve electric system reliability while minimizing pressure on the FCRPS/existing PNW hydro system as the de facto fallback when the region is capacity short (with predictable adverse impacts on salmon). A principal feature of this program should establish a planning reserve margin (PRM), or reliability buffer, to guard against unanticipated reliability events and protect the region's natural and cultural resources. While individual utility PRMs have typically centered around 15 percent, the Resource Adequacy program should increase this buffer to 20 percent which would parallel what the CAISO has already recommended to help solve California's reliability problems. This single change could also provide measures for a dry water year strategy as described in section 3.5.2 of the attached CRITFC's 2013 Energy Vision.

CRITFC recognizes that many conditions have changed since 2013 and is in the process of updating the Energy Vision. There may be better ways to maintain the reliability of the electrical system while protecting anadromous fish.

The actions described in the forward showing program conceptual design (Section 2) and the operational program conceptual design (Section 3) appear to include the traditional techniques to track and address resource adequacy. As CRITFC works to prepare its 2021 update of the Energy Vision, we are struck by the significant improvements in the costs of renewable resources and energy efficiency and the advancements in storage, microgrids, and demand management.

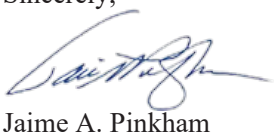
California's experiences have shown that these renewable and significant future distributed resources must be considered and addressed as resource adequacy programs are developed. There appear to be additional opportunities for interregional energy transfers. Given the importance of resource adequacy, the region's public utility commissions may also be willing to address time-of-use and other pricing techniques to address peak loads. We recommend the Power Pool expand its scope to address these additional ways to improve resource adequacy.

We believe it is important for the Northwest Power Pool to fully consider fish and wildlife protections as part of its resource adequacy program. We would like to see fish and wildlife protection incorporated into the goals and objectives and detailed analysis of your resource adequacy program. There may be ways to improve resource adequacy and also improve the survival of anadromous fish. There may be other alternatives that make things worse for these important tribal resources.

The Northwest Power Pool and its members have the expertise to evaluate these issues. We ask Pool's program to include a dry-year strategy, recognize new energy and policy opportunities, and address the effects on fish and wildlife in providing resource adequacy for the PNW.

We would also be willing to discuss ways to coordinate our update of the Energy Vision with the work you are doing. For questions and follow up, please contact Christine Golightly, Policy Analyst, via email at golc@critfc.org

Sincerely,



Jaime A. Pinkham
Executive Director

Cc: Bill Drummond, Board Chair, Northwest Power Pool, WKDrummond@comcast.net
Richard Devlin, Chair, Northwest Power and Conservation Council
John Hairston, Administrator, Bonneville Power Administration

Attachment

Columbia River Inter-Tribal Fish Commission (CRITFC)
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www.critfc.org/energy-vision