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.



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**.

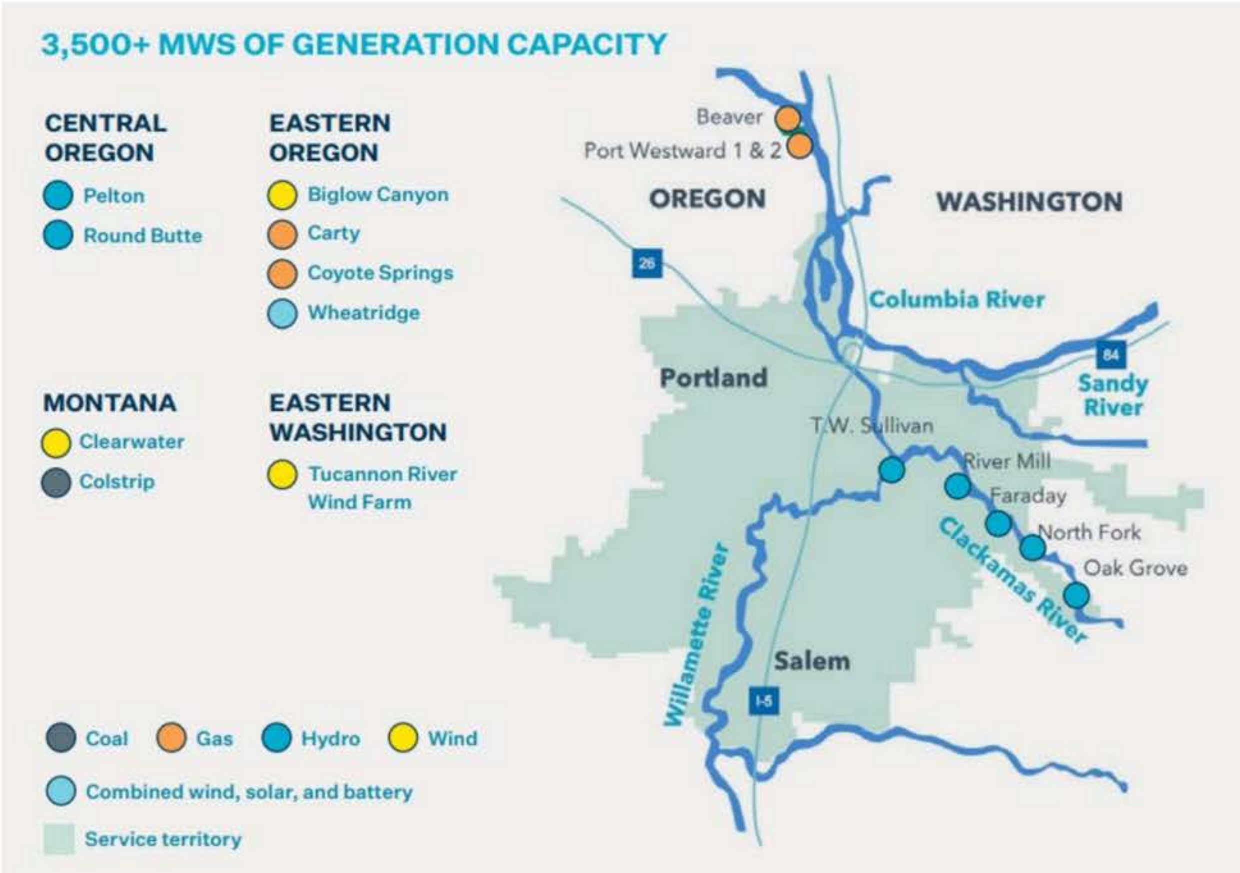
## 1.2 Historical emissions trends and resource mix

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**

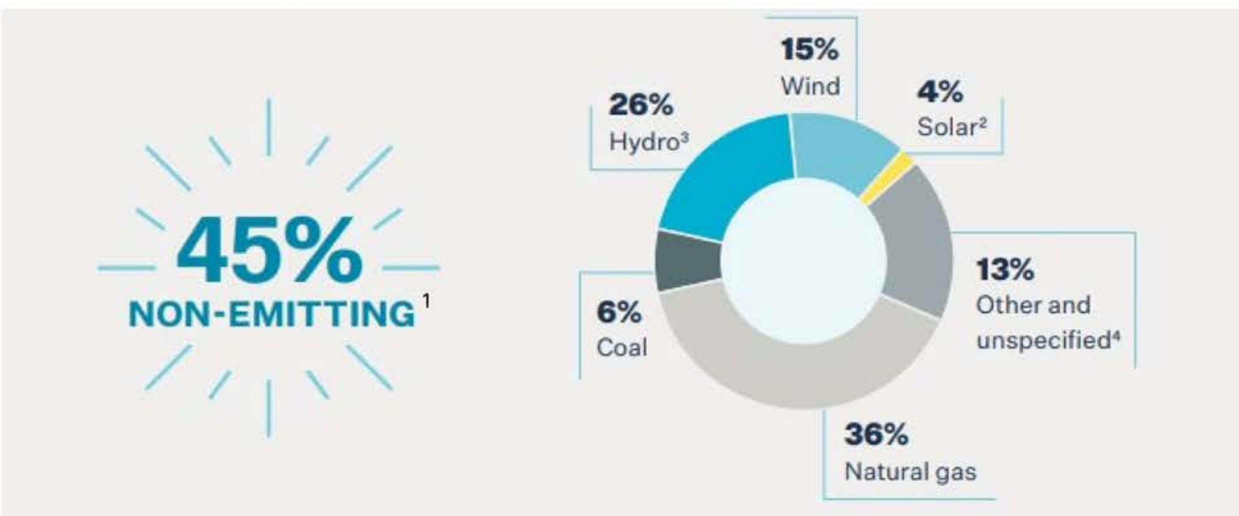



Customer-sited resources, including rooftop solar, batteries and standby generation play an increasingly critical role in the resource portfolio. For example, customer-sited rooftop solar generation contributed an additional 264,826 MWh of non-emitting energy in PGE service territory in 2024. PGE manages 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**

## CLEAN ENERGY ADDITIONS*

**Achieving emissions reduction requires steadily adding renewable energy, battery storage, energy efficiency and demand response to our portfolio, so we can reliably and affordably reduce fossil fuel generation.**

**Since PGE implemented its emission targets in 2021, PGE and its customers have committed to adding 2,900+ MW of clean energy.**

### Clean energy additions since 2021

**Wind**
- Clearwater 2024: 311 MW

**Utility scale solar**
- Wheatridge Solar 2022: 50 MW
- Patchwayit Solar** 2023: 162 MW
- Tower Solar** 2026: 120 MW
- Daybreak Solar** 2026: 138 MW
- Bakeoven Solar** 2026: 60 MW

**Batteries**
- Wheatridge Battery 2022: 30 MW
- Constable 2024: 75 MW
- Sundial 2024: 200 MW
- Coffee Creek 2024: 17 MW
- Seaside 2025: 200 MW
- Other BESS facilities: 8 MW

**Small-scale solar**
- Community Solar & QFs: 96 MW
- Rooftop Solar: 172 MW

**Hydro contracts**
- Mid-C PPA 2023 (2024-2025): 76 MW
- Mid-C PPA 2023 (2024-2026): 434 MW
- Douglas PUD 2024 (2026-2030): 79 MW

**Customer programs**
- Energy Efficiency***: 122 aMW
- Demand Response****: 603 MW

### Next steps:

**PGE received Commission acknowledgement to pursue over 1,600 MWs of renewable energy and storage from its 2023 All-Source RFP final short list.**

**PGE will solicit the market through RFPs for renewable energy resources and storage, starting again in 2025.**

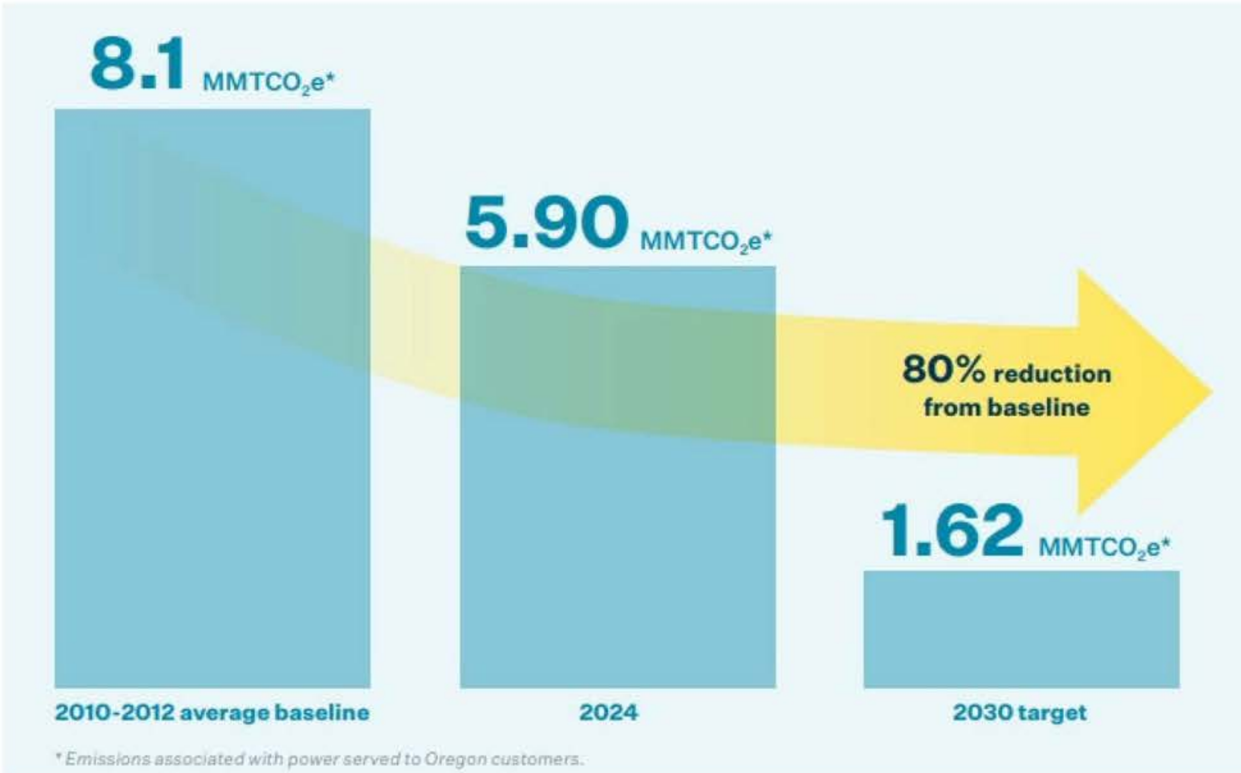
**PGE is executing on plans to shift up to 25% of peak energy demand through distributed resources and customer programs coordinated through our virtual power plant.**

** Through ownership, PPA, contract or customer participation in programs.*
*** Procured by customers through Green Future Impact program.*
**** Preliminary numbers as provided by ETO. Numbers are subject to change from this report to the final filed report, which will occur later in the year.*
***** Cumulative capacity deployed in summer and winter seasons over time period. Total DR capacity in Summer 2024 is 105 MW.*

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.

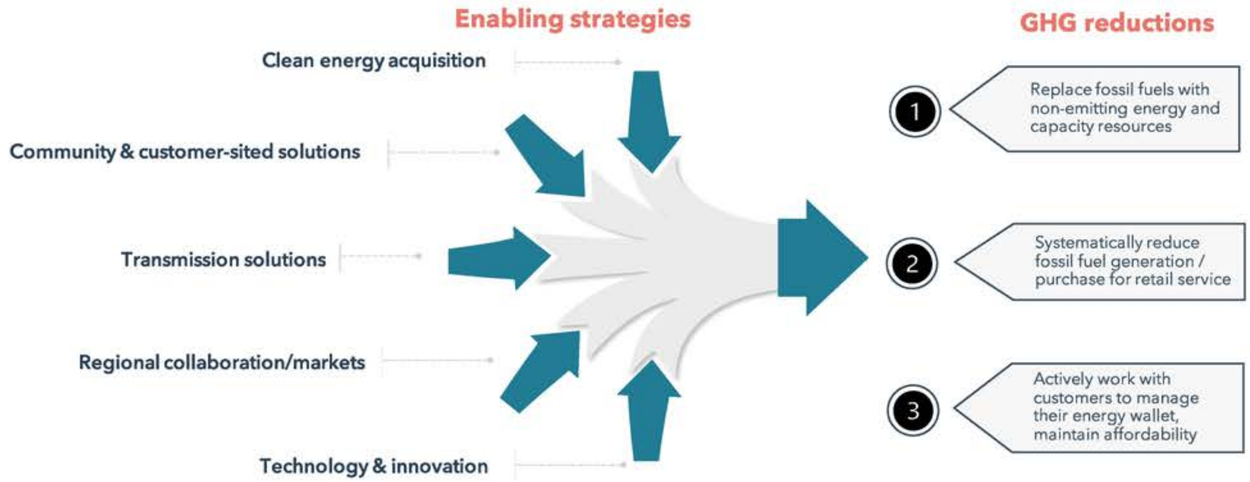
This CEP/IRP Update reflects a significant increase in need for procurement of new generation and storage capacity to keep pace with new customer demand as well as to make progress toward emissions targets. The utility is also considering ways to allocate relevant costs fairly to customers that have 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**



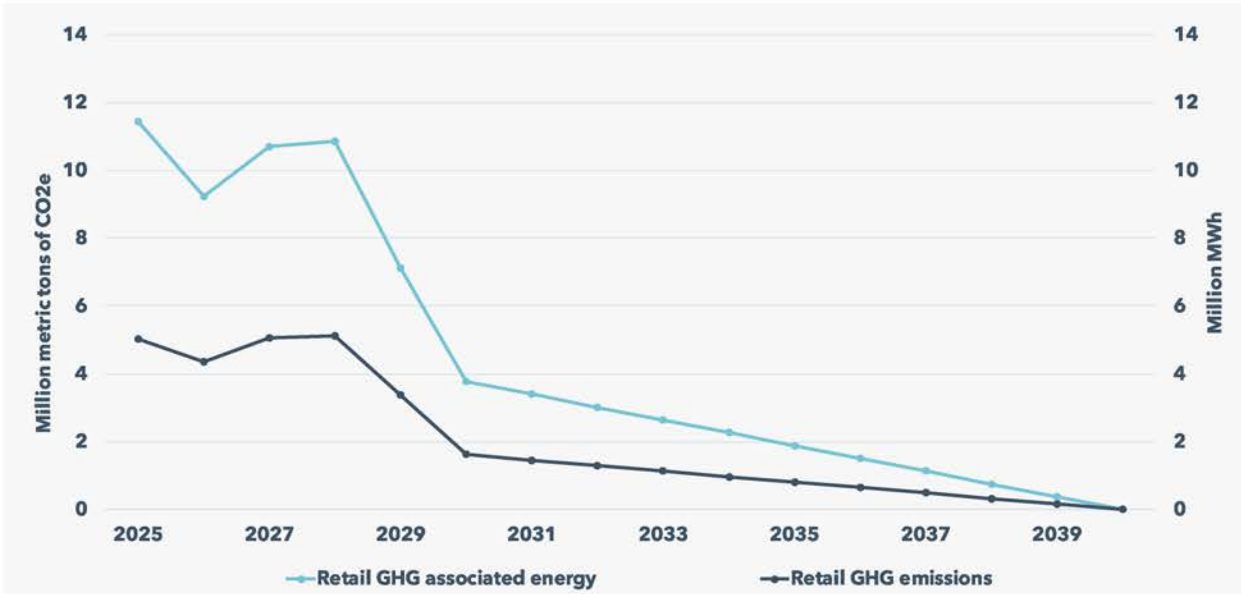

This high-level approach to decarbonization involves gradually reducing fossil fuel generation and purchases for Oregon retail customers and replacing it with non-emitting energy resources and capacity, as well as key enabling strategies to facilitate a reliable and affordable transition. The IRP estimates 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**

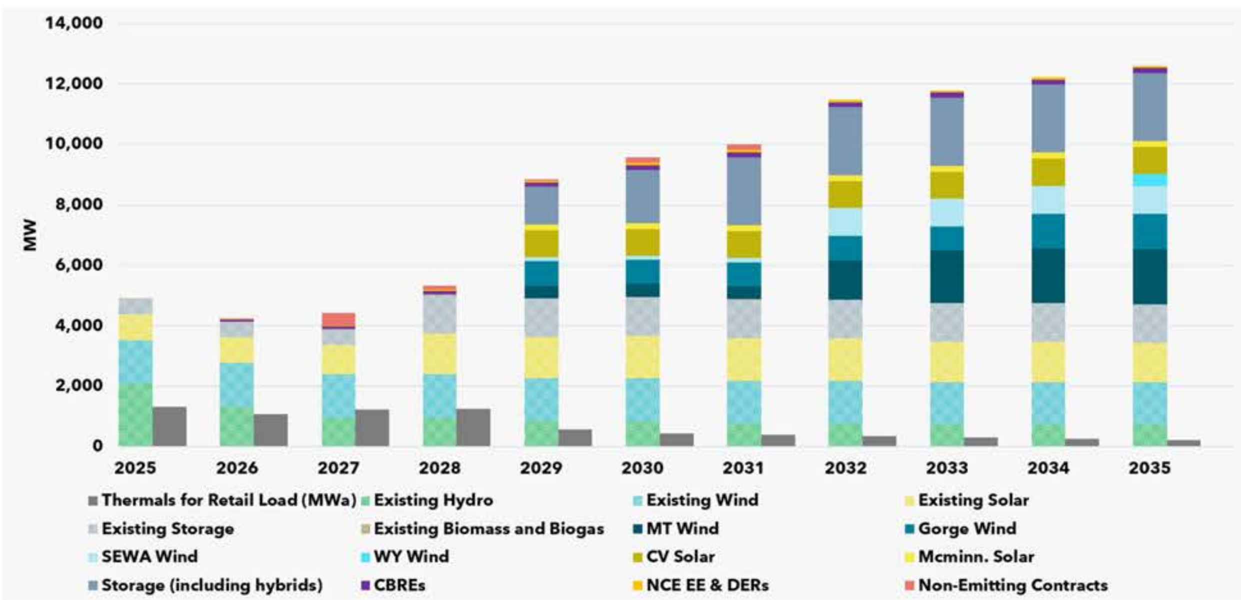



**Figure 8** shows the Preferred Portfolio incremental resource additions through 2030 along with changes to PGE's existing portfolio of resources for a view of total generating capacity. The capacity of existing thermals shown in **Figure 8** does not reflect emissions target-driven reductions in emitting 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**

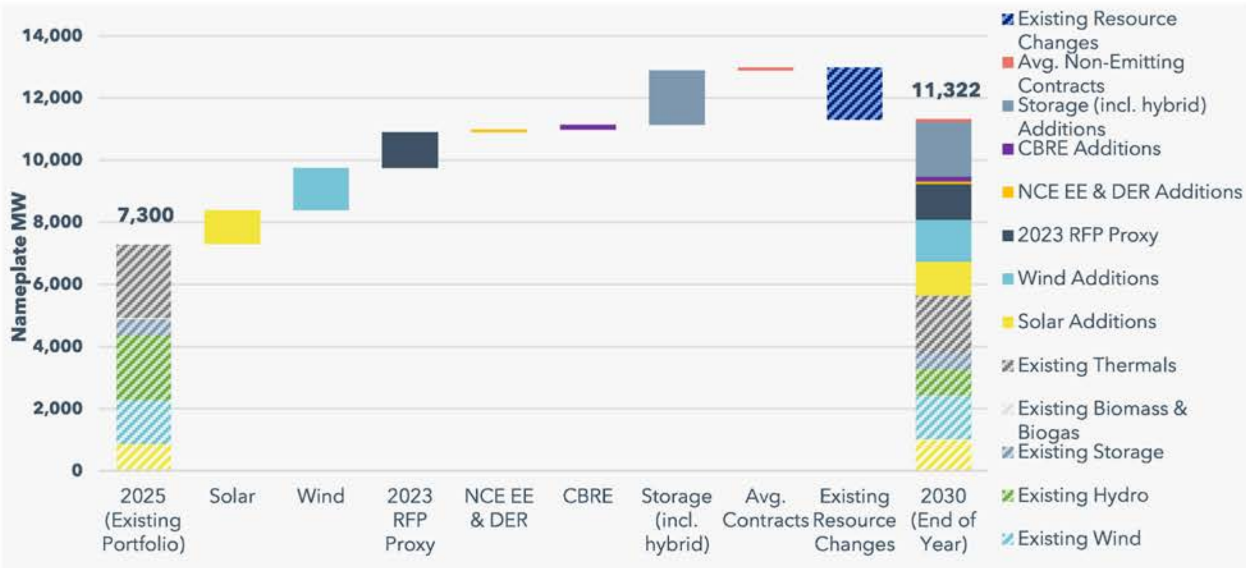



**Table 1** provides a summary of total resource actions from 2025 through 2030 as cumulative buildout within this timeframe. The analysis demonstrates the ability to meet the 2030 target using resources that are currently known and have been commercially available. Between now and 2030, PGE's thermal 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.

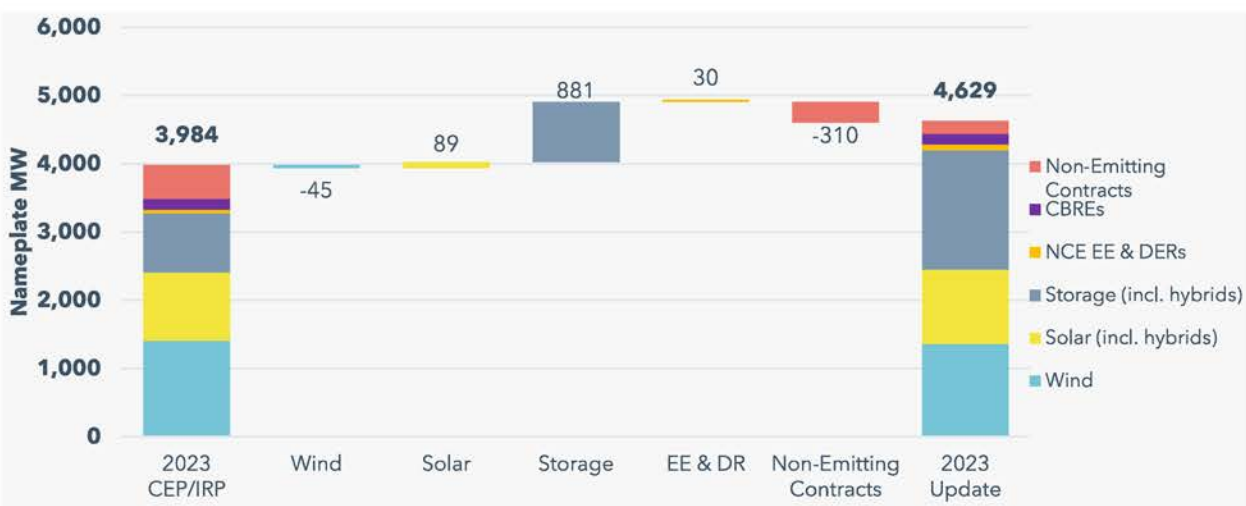
PGE's 2023 CEP/IRP Action Plan remains robust, and therefore, PGE is not requesting modifications or seeking acknowledgment of this Update. Updated analysis described throughout this report suggests resource need has increased, driven mainly by growing demand and the need to maintain resource adequacy. 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.

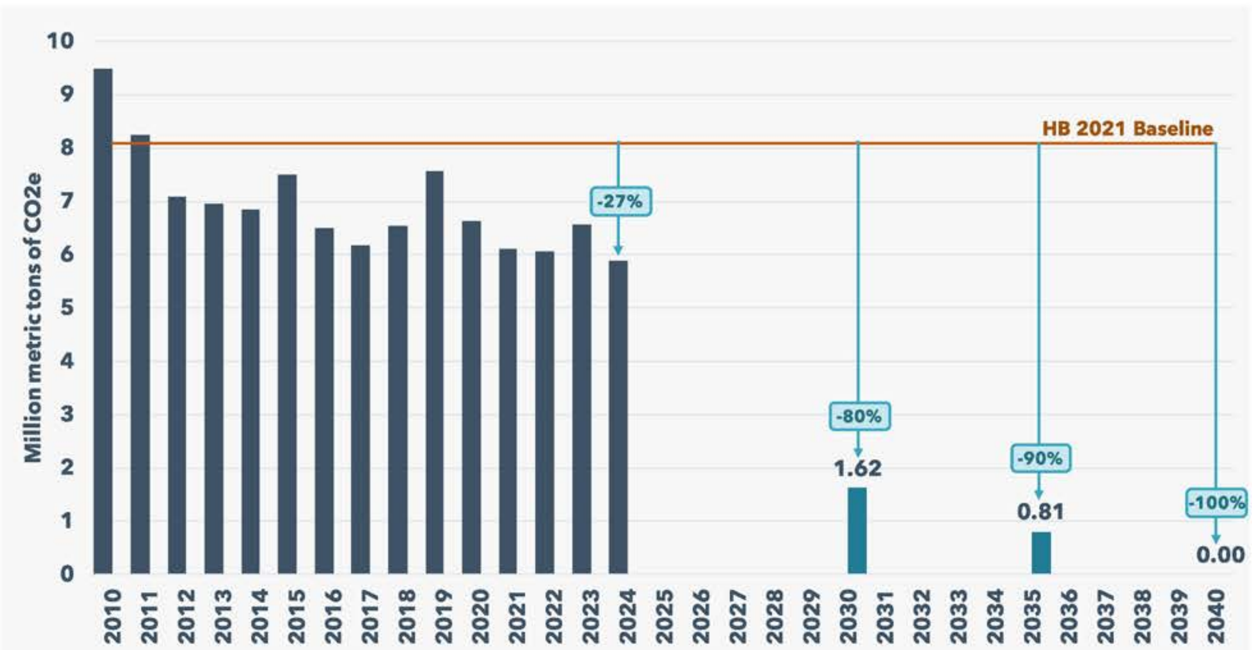
To examine the optimal progress toward the 2030 emissions target in portfolio analysis, PGE analyzed various GHG glidepaths in the 2023 CEP/IRP. Ultimately, the Preferred Portfolio that informed the Action Plan was constructed in a way that minimized the costs and risk of new resource acquisitions and 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.

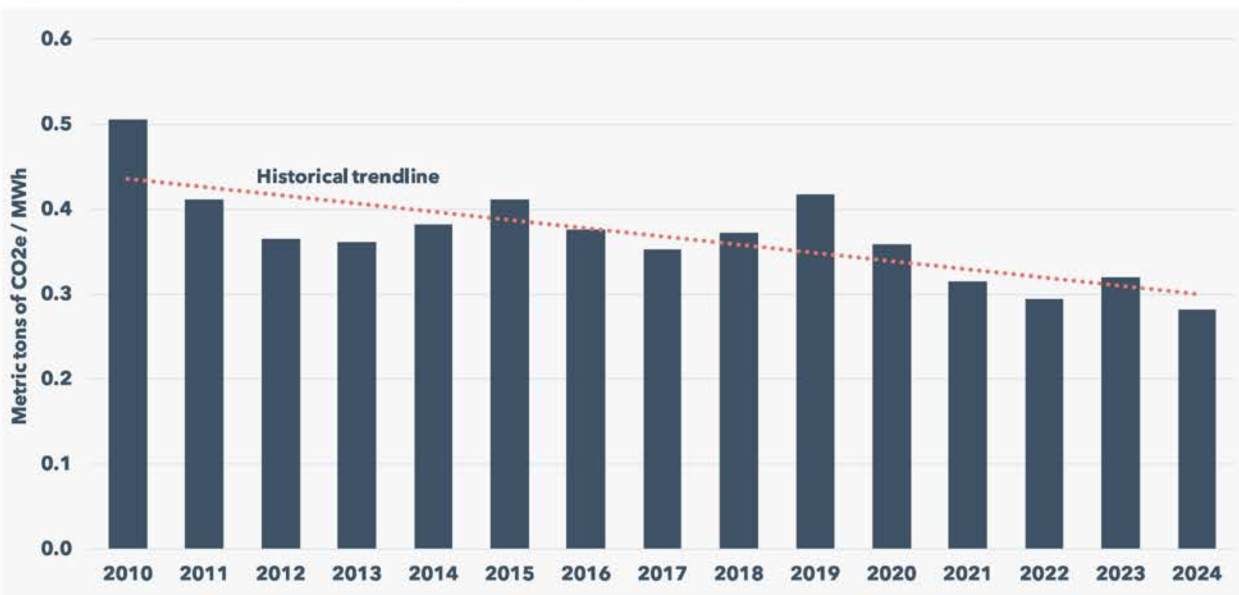
[8] In the Matter of Public Utility Commission of Oregon, House Bill 2021 Investigation into Clean Energy Plans, Docket No. UM 2225, Order No. 22-390 (Oct 25, 2022), Attachment #1 at Topic #8, available at https://apps.puc.state.or.us/orders/2022ords/22-390.pdf.

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<br>…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:<br>• 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.<br>• 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.<br>**Section 6.2.2** discusses hourly energy and emissions accounting results.<br>PGE resubmitted the forecast for DEQ review in June 2025 prior to the filing date for this Update. |
| Transmission Analysis and Alternatives<br>…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<br>…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<br>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<br>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:<br>…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:<br>…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:<br>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:<br>…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

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[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.

[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<br>Other Residential<br>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**

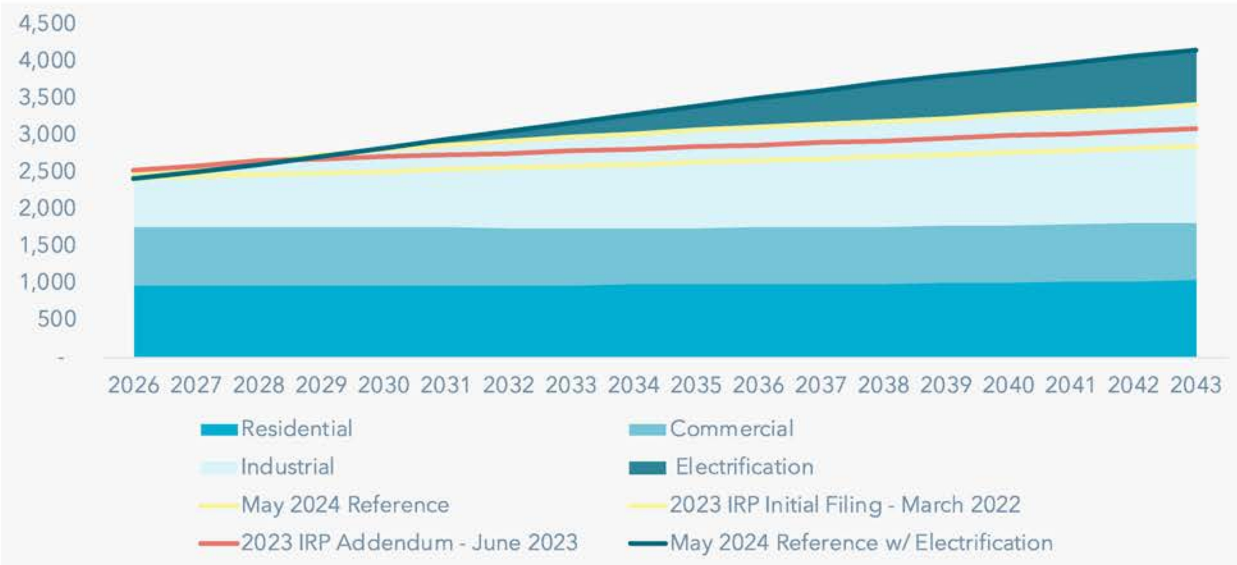



**Table 7** presents a tabular growth rate summary comparison of the forecast vintages.

**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.

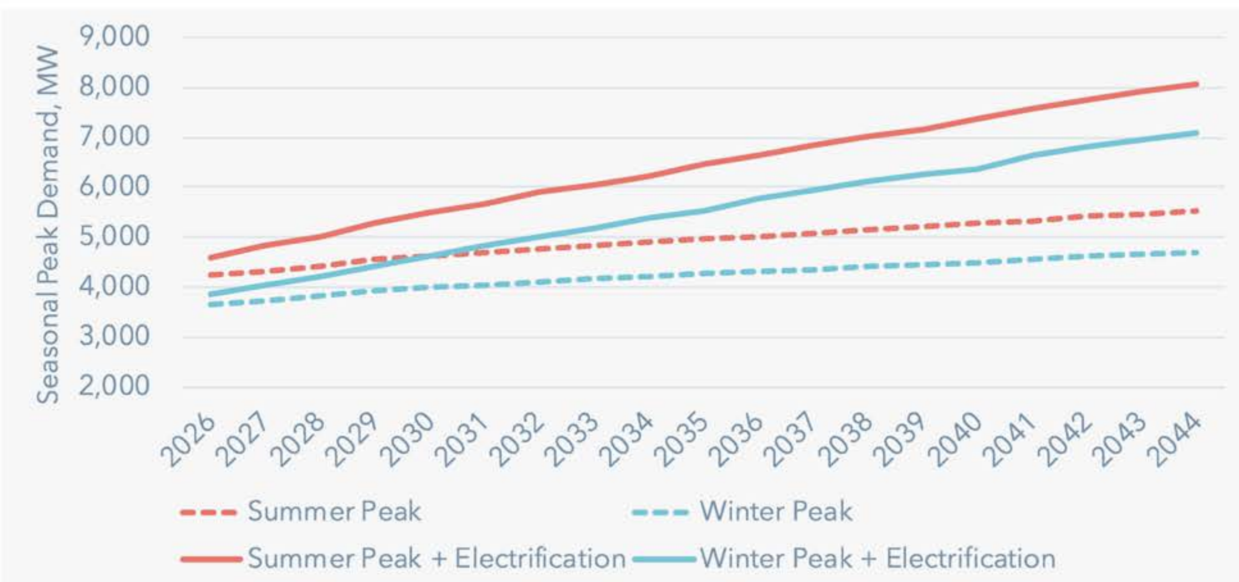
For the May 2024 forecast, PGE updated its peak demand model with a focus on better capturing recent response to warm summer temperatures. The updated peak demand model uses hourly data by customer class – residential, commercial, and industrial – for 2019-2023 to better capture current usage trends 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**.

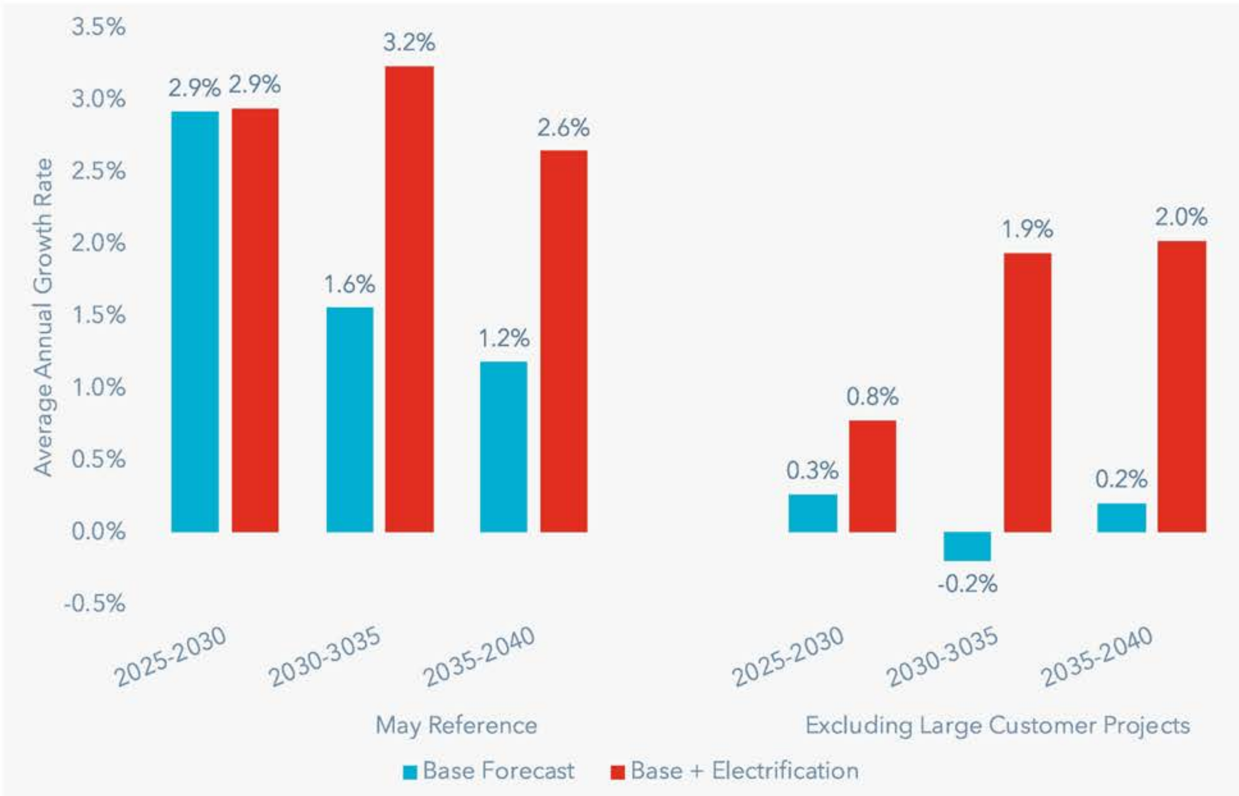
**Table 10. Twenty-year average annual growth rate comparison, Excluding Large Customer Projects**

| | 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**



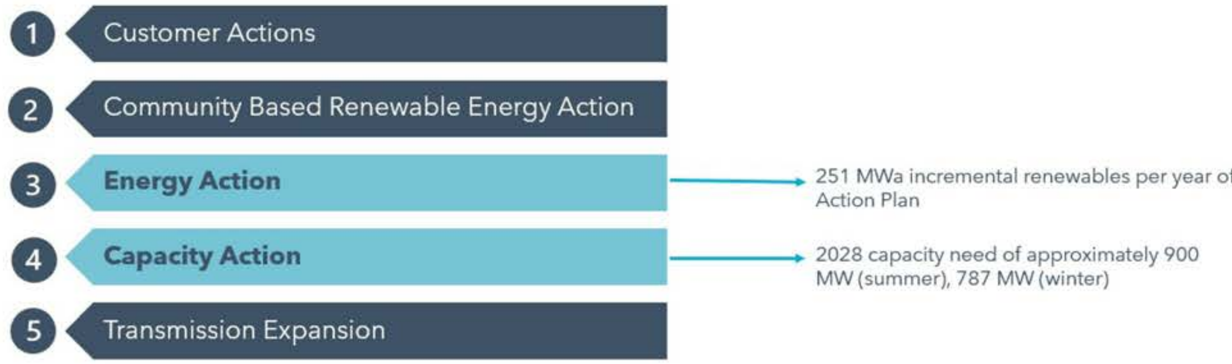

## 3.2 2023 RFP results

### 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**

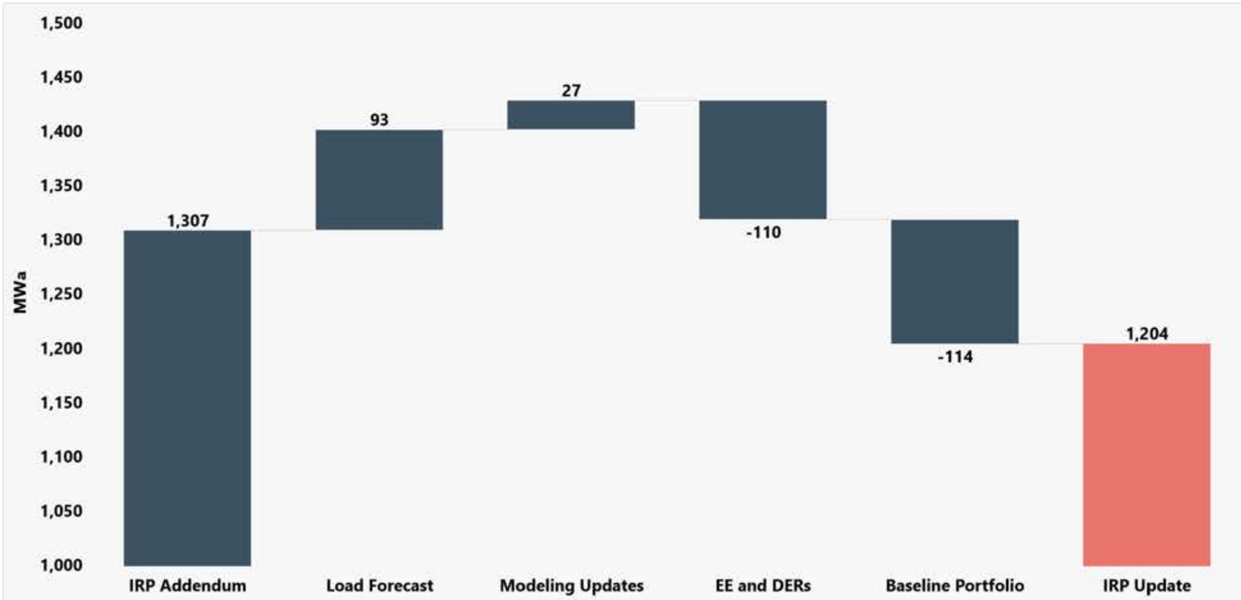
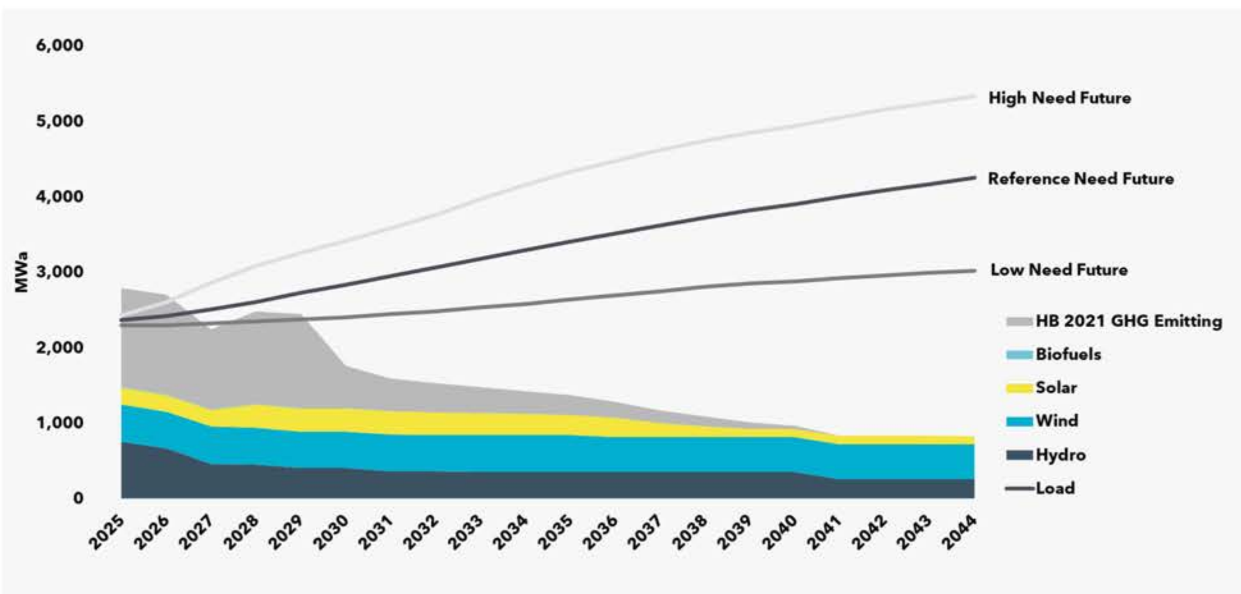


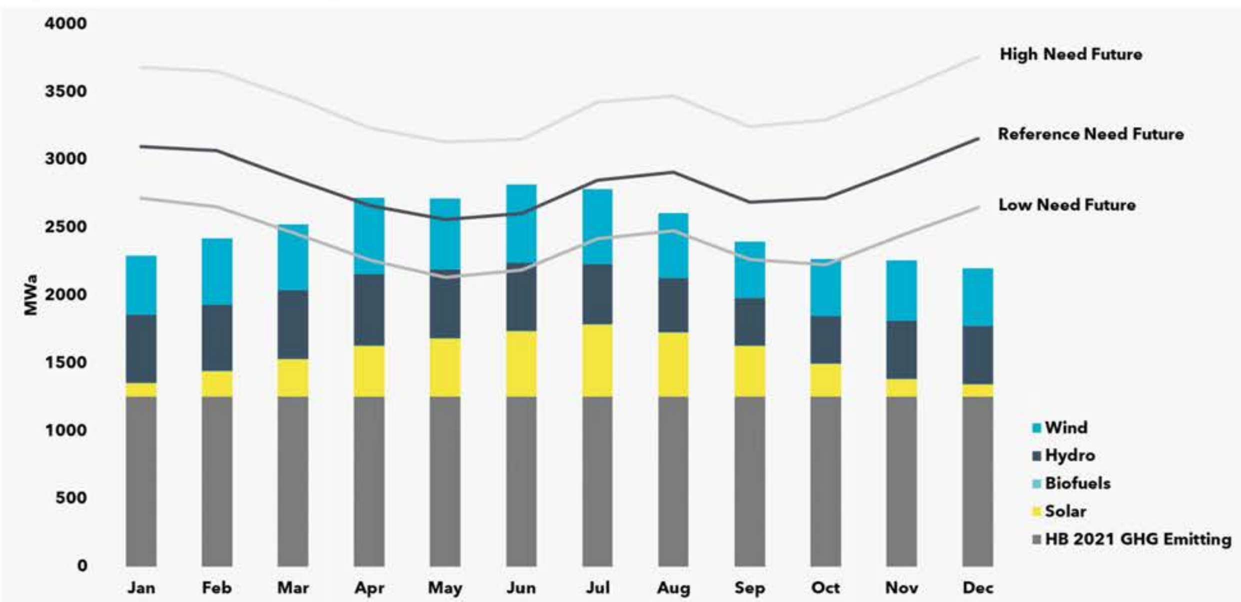

**Figure 20. Annual energy-load resource balance from 2025 through 2044**




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**

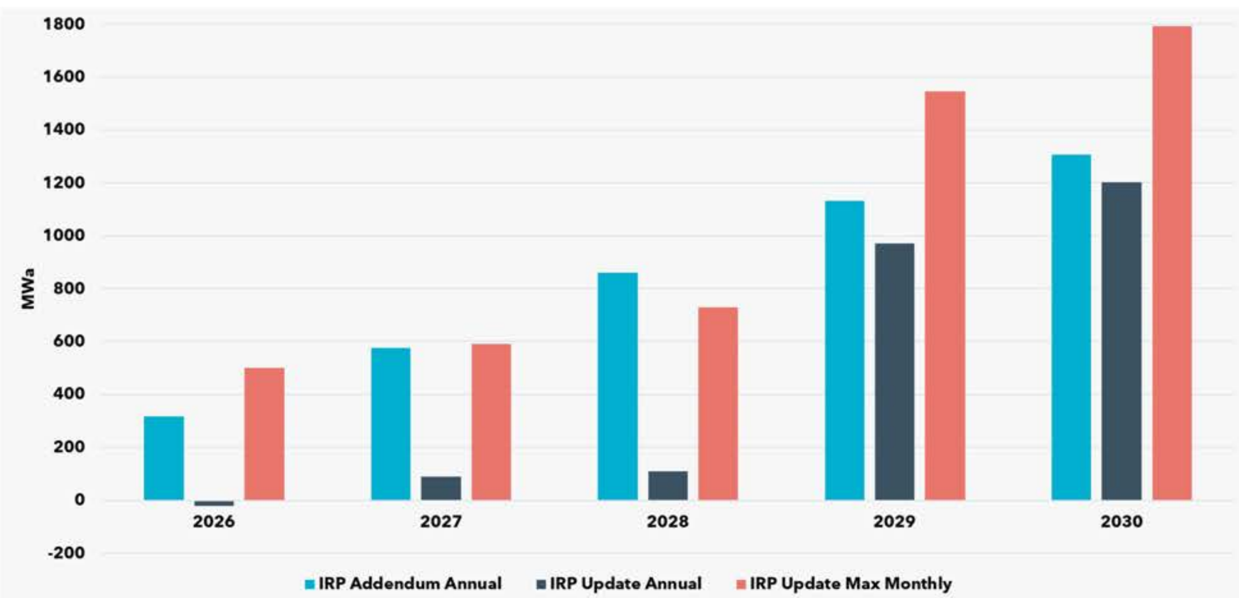



Seasonal dynamics can have important implications for resource planning and influence the optimal quantity and mix of resources in the portfolio. The magnitude of energy need in a given month may exceed the energy need on average across the year, increasing the quantity of resources needed. The timing 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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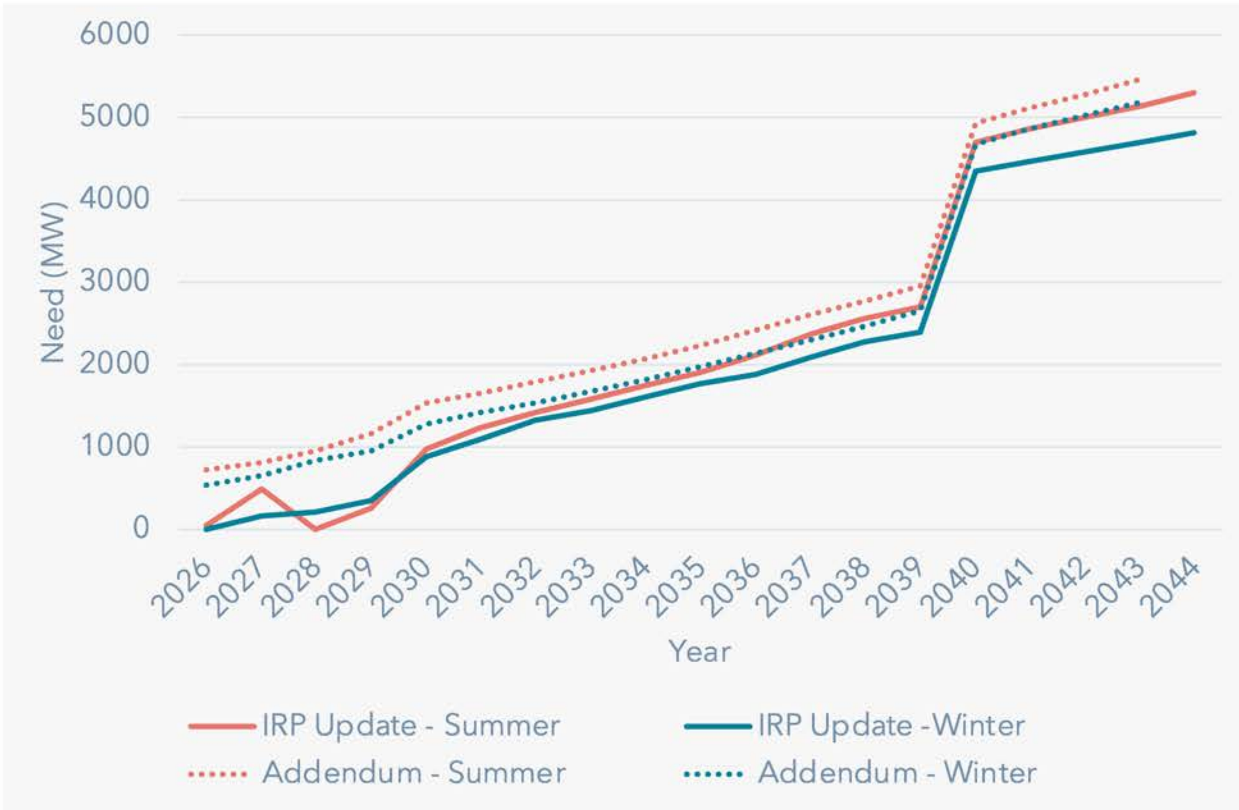
[61] The following resources provide descriptions of Sequoia from past roundtables and filings: 2019 IRP Update Sequoia overview - Appendix K; 2023 CEP/IRP Sequoia overview – Appendix H.3; May 2021 CEP/IRP Roundtable; March 2022 CEP/IRP Roundtable; January 2023 CEP/IRP Roundtable; August 2024 CEP/IRP 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**

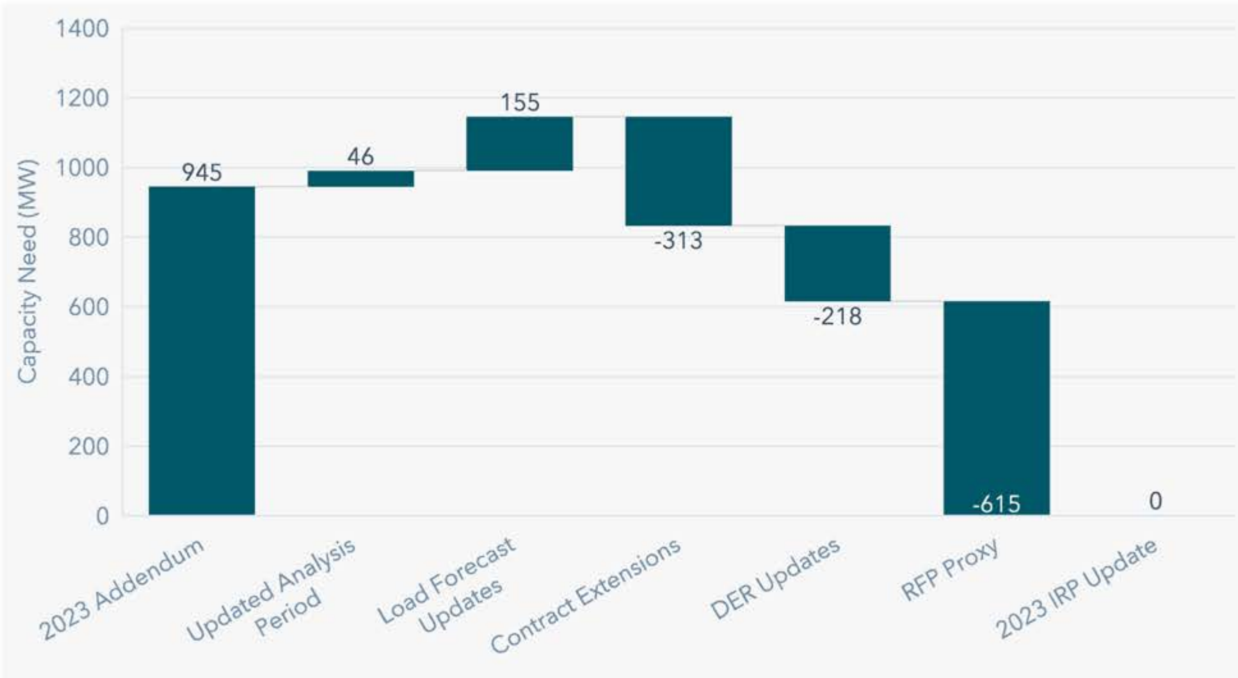
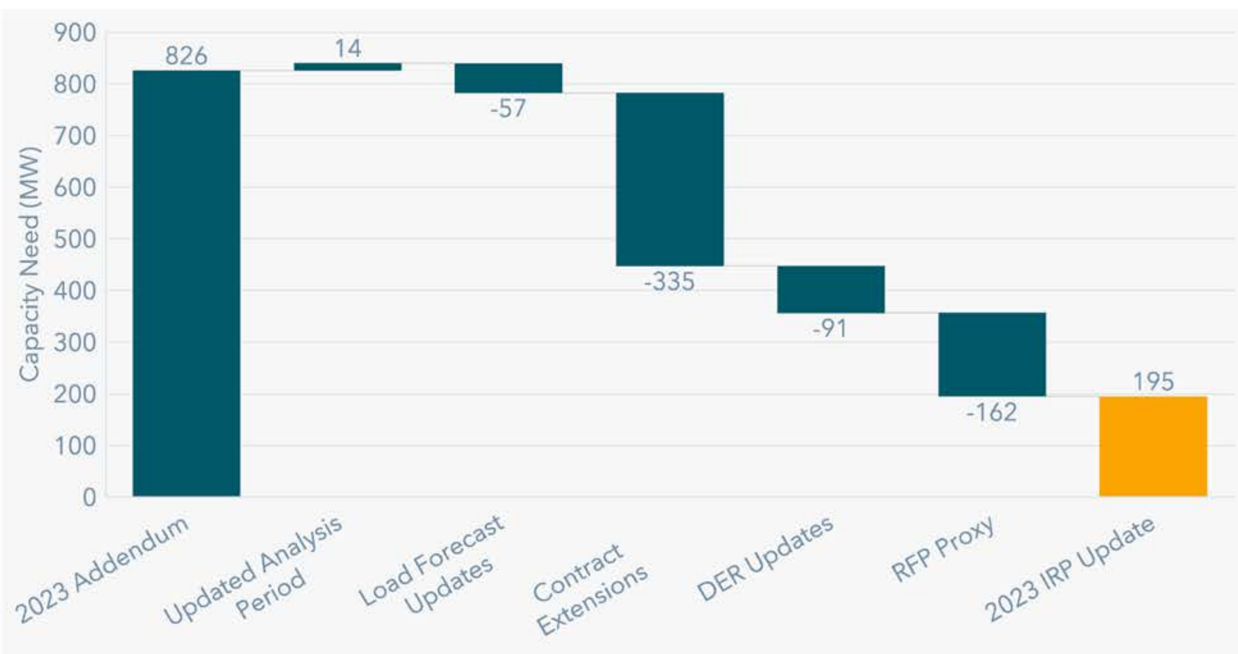


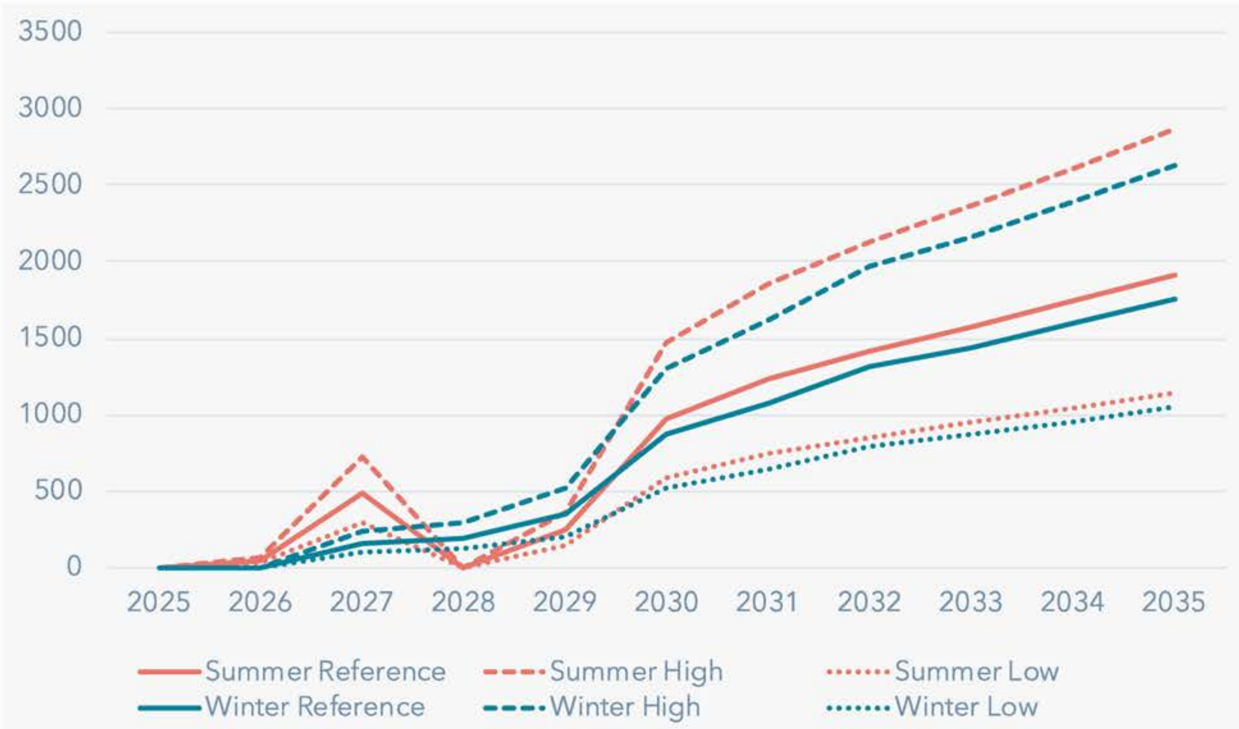

**Figure 25. Incremental Changes to Capacity Need - Winter 2028 Reference Case**




### 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

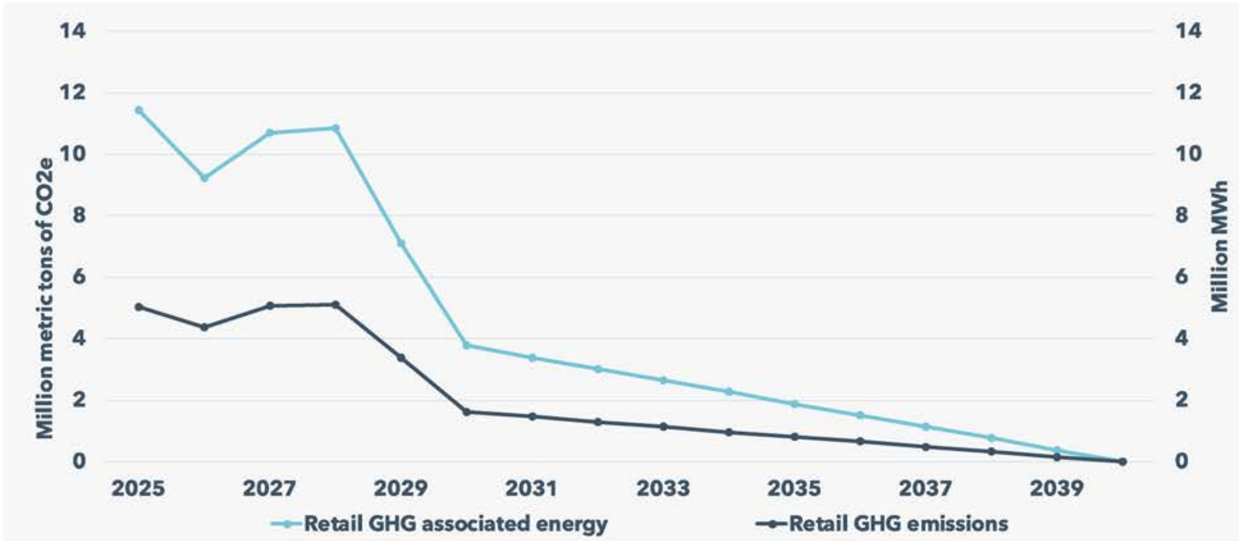
This section describes how State policy requirements are imposed through the utility regulatory framework and updates PGE made to reflect these constraints as part of the 2023 CEP/IRP Update.

### 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)**

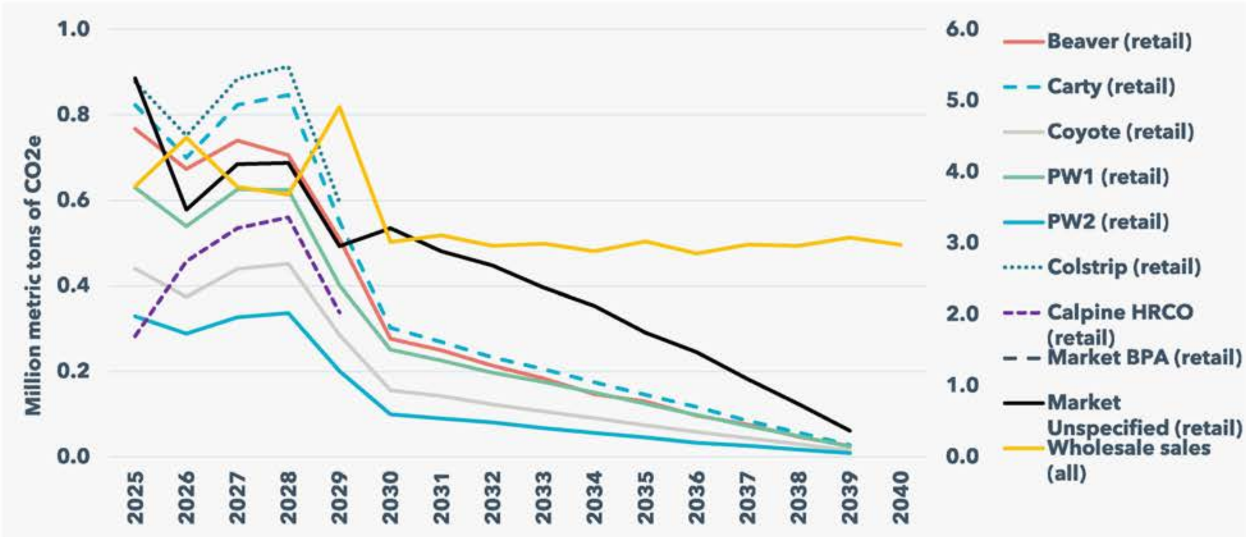



**Figure 28** reflects GHG emissions projections from thermal generation and market purchases under the updated decarbonization glidepath. The lines specific to individual resources show retail GHG emissions. The specified wholesale sales category captures GHG emissions from sales from all sources not 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.

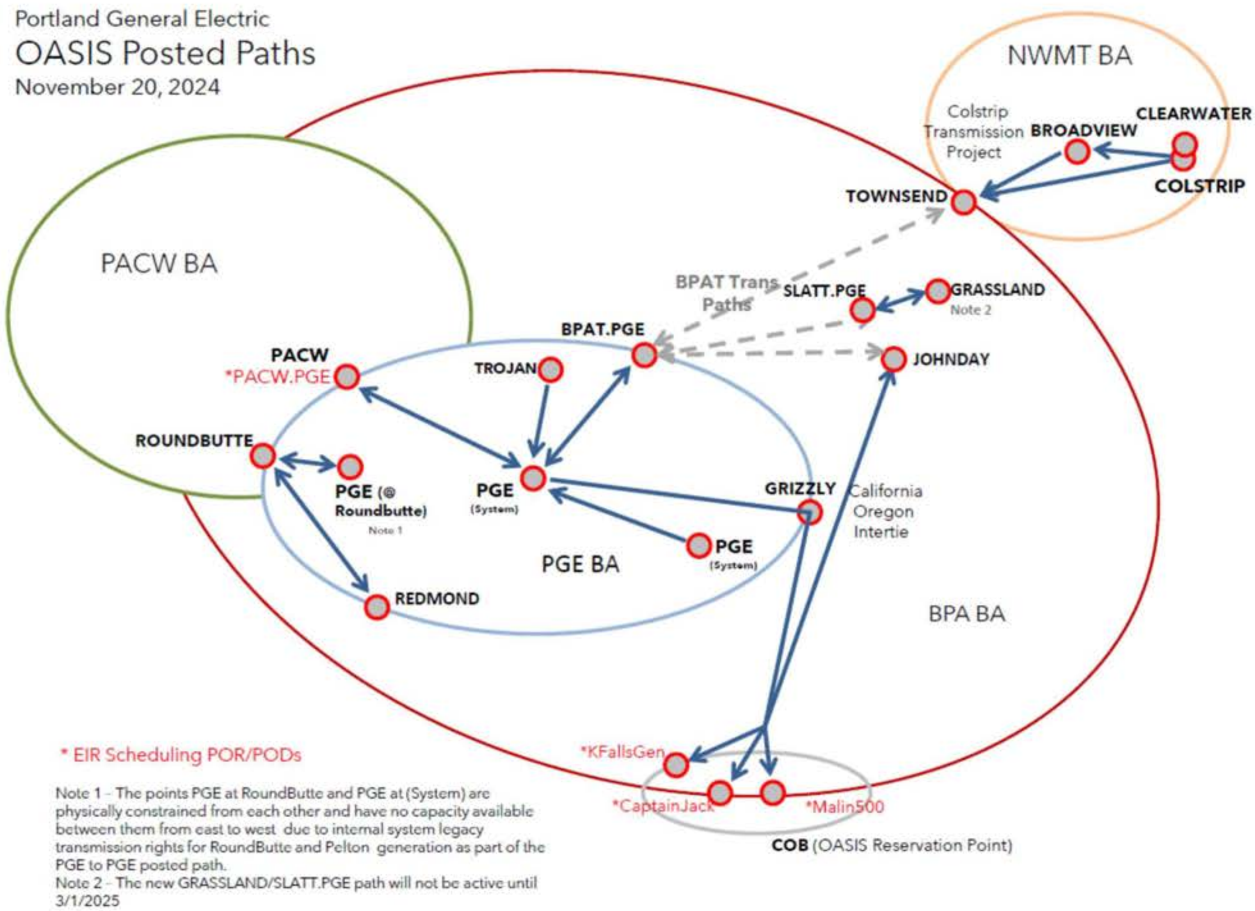
The PGE transmission system has 268 miles of 500 kV, 334 miles of 230 kV, and 559 miles of 115 kV lines, 454 circuit miles of 57 kV lines, and includes 176 substations and switching stations.[70]

### 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.

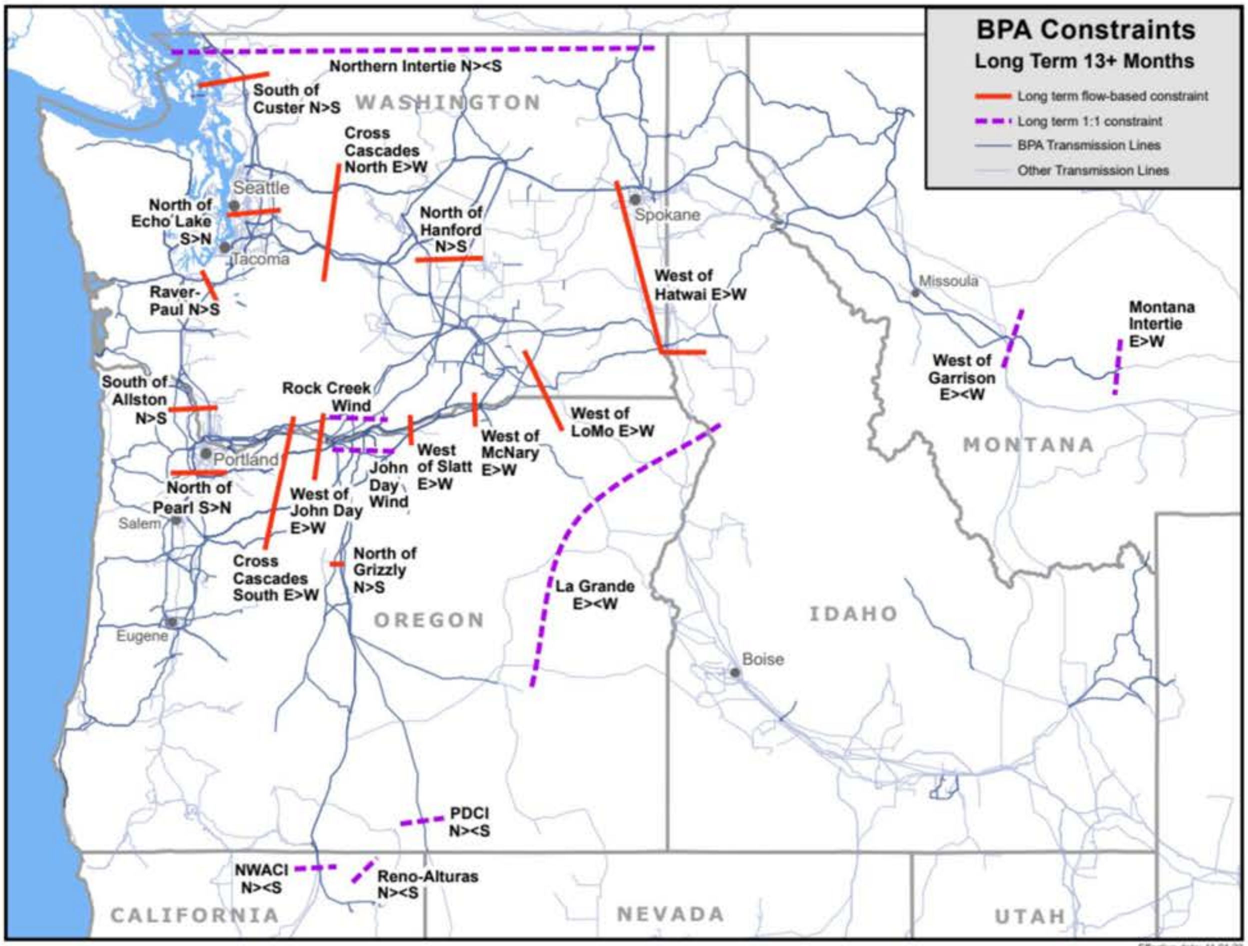
#### 4.1.3.3 Paths and flowgates

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 |

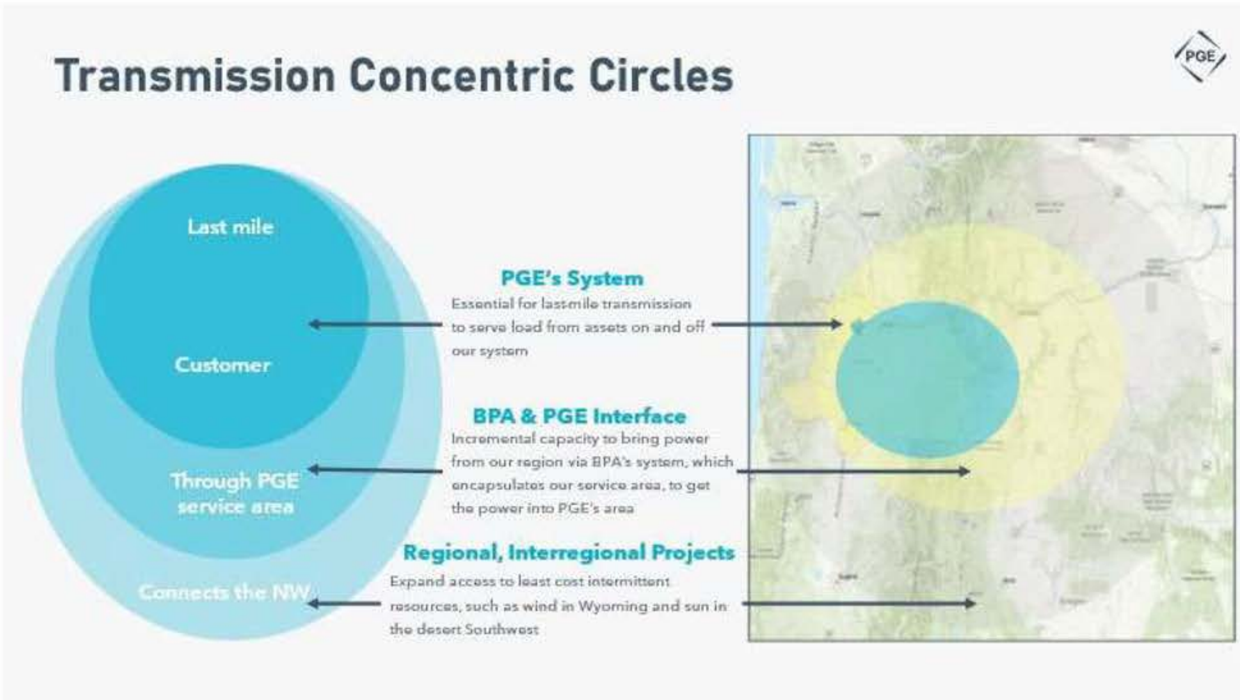
## 4.3 Transmission strategy/outlook

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**

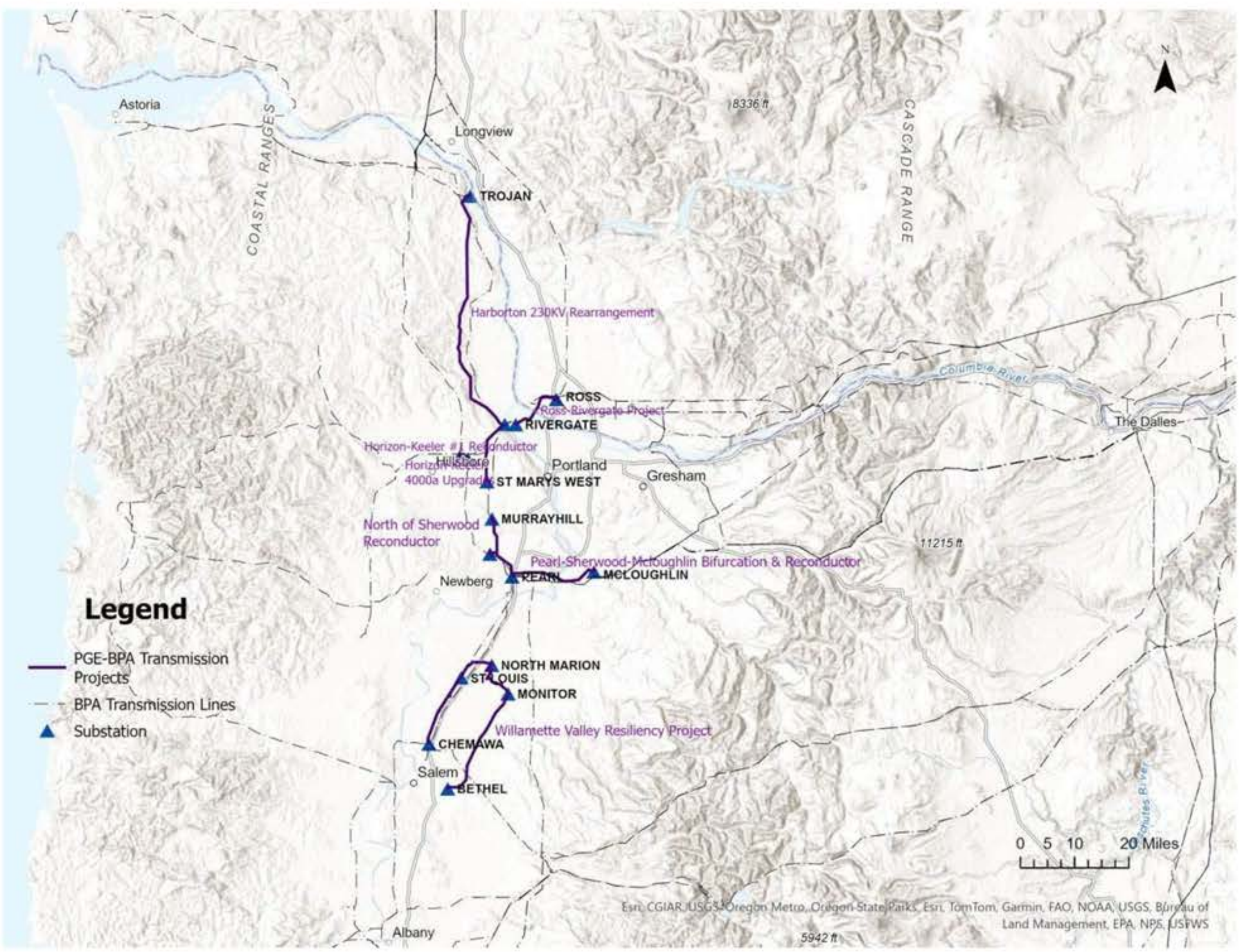
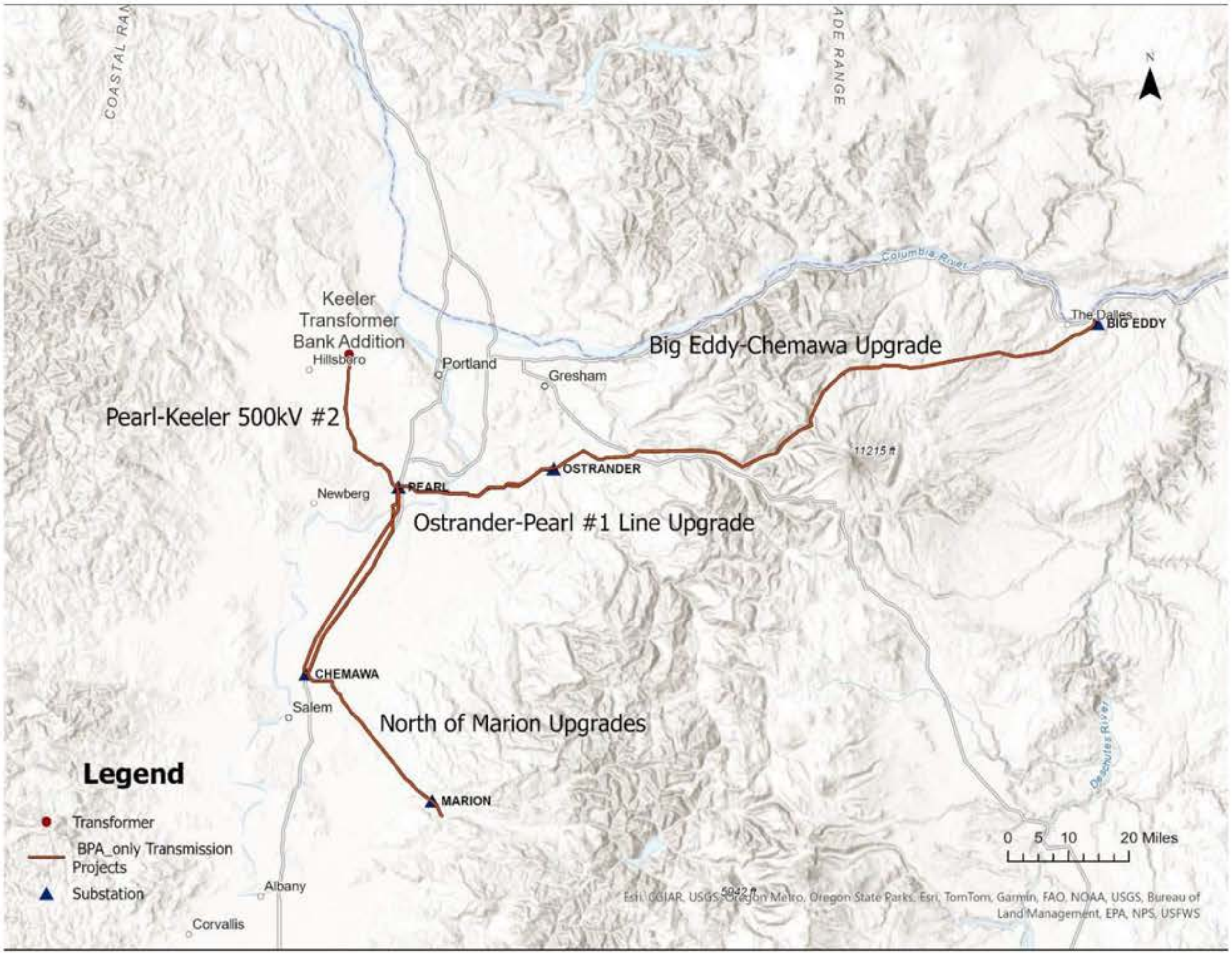


**Figure 33. BPA-only transmission projects**




## 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<br>Christmas Valley Hybrids |
| **Gorge** | Gorge Wind<br>Wasco Solar |
| **McMinnville** | McMinnville Solar<br>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

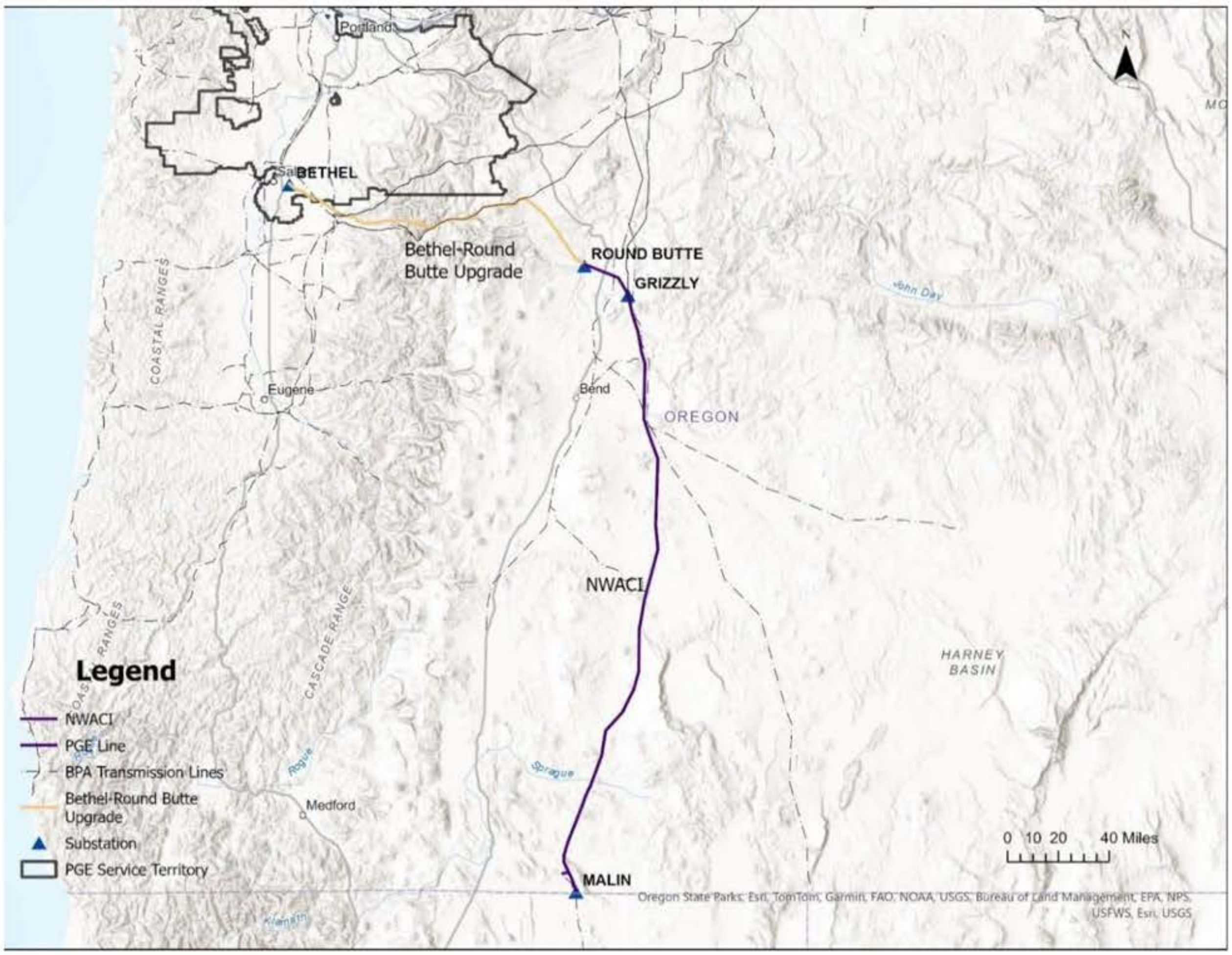
Bethel-Round Butte transmission project is a 98-mile 230 kV line upgrade running between PGE's Bethel and Round-Butte substations at the south-east edge of PGE's service territory. The project plans to rebuild the existing transmission line from 230 kV to 500 kV and build a second 500 kV line, enabling 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.

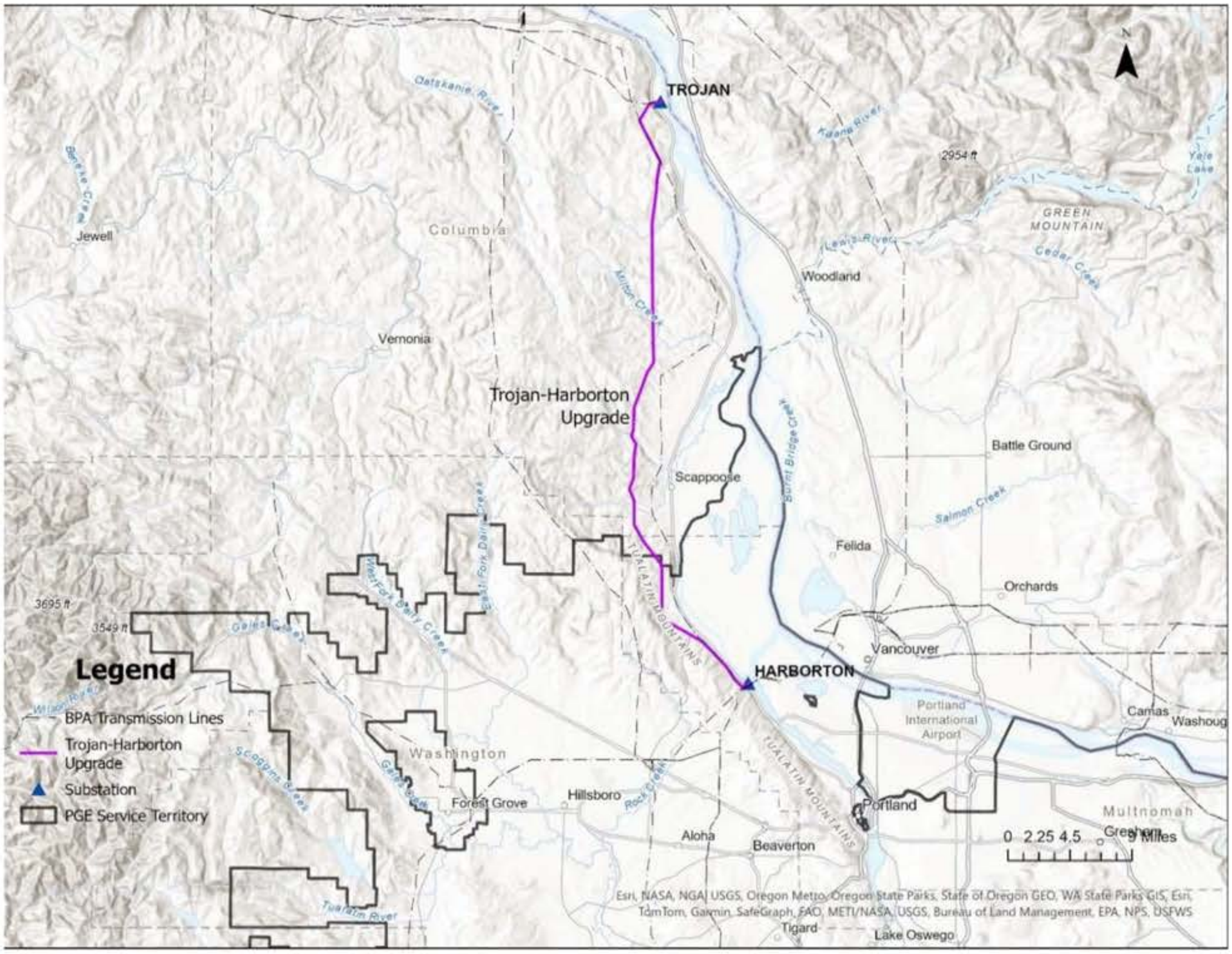
**Figure 35. Bethel-Round Butte Upgrade**




## 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**



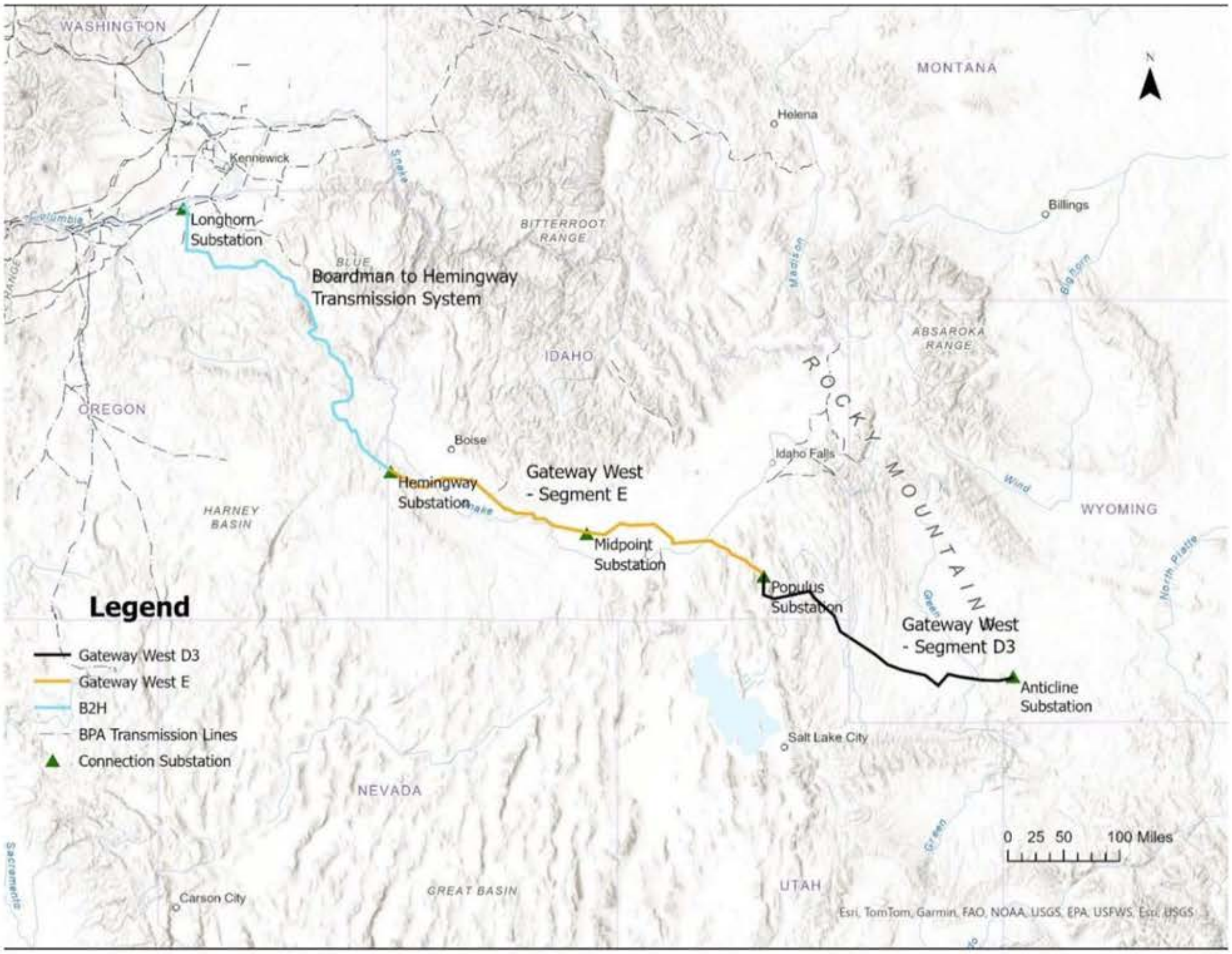

## 4.6.3 Gateway + B2H + Longhorn (Gateway)

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**



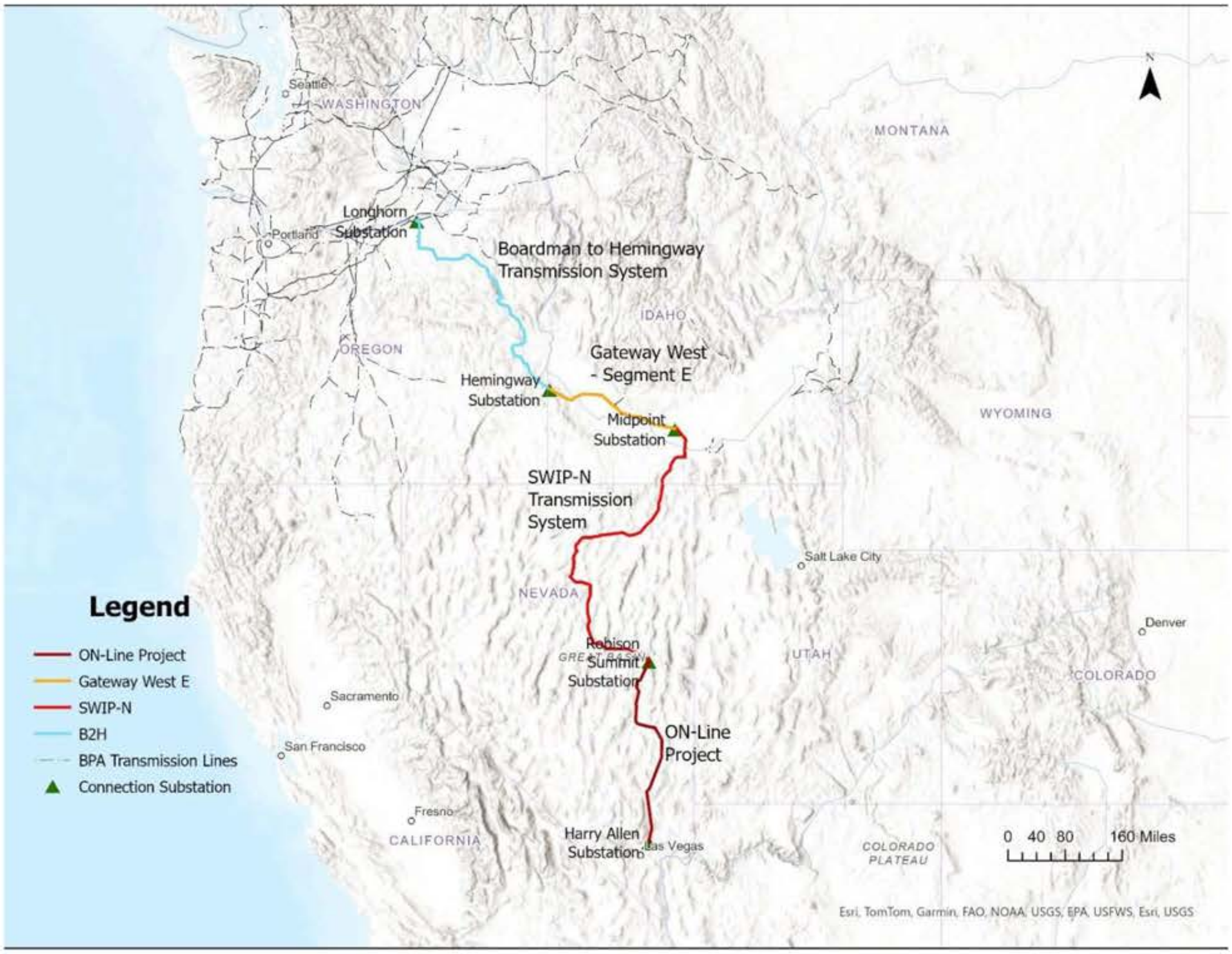

## 4.6.4 NVE + SWIP-N + Gateway + B2H + Longhorn (SWIP-N)

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.

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[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.

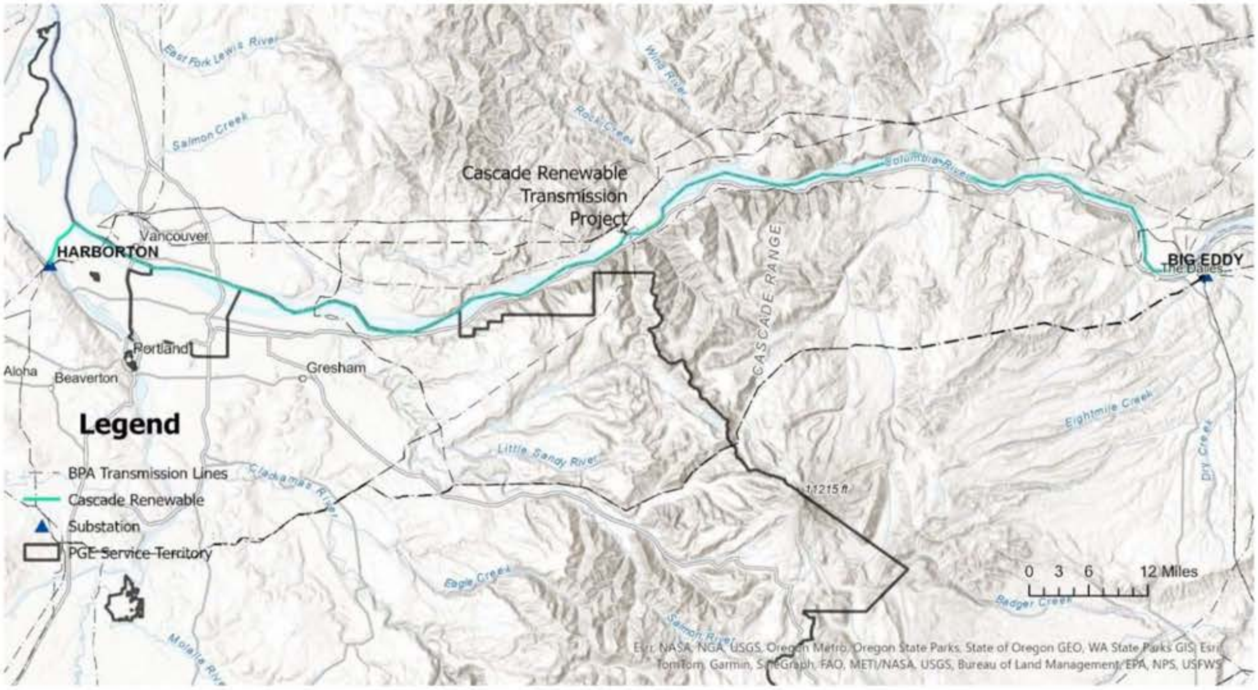
**Figure 40. Greenlink Transmission Option**


## 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] ($/kW) IRP | Update | Fixed Costs[99] ($/kW-yr) | LCOE[100] ($/MWh) 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] ($/kW) IRP | Update | Fixed Costs[99] ($/kW-yr) | LCOE[100] ($/MWh) IRP | 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

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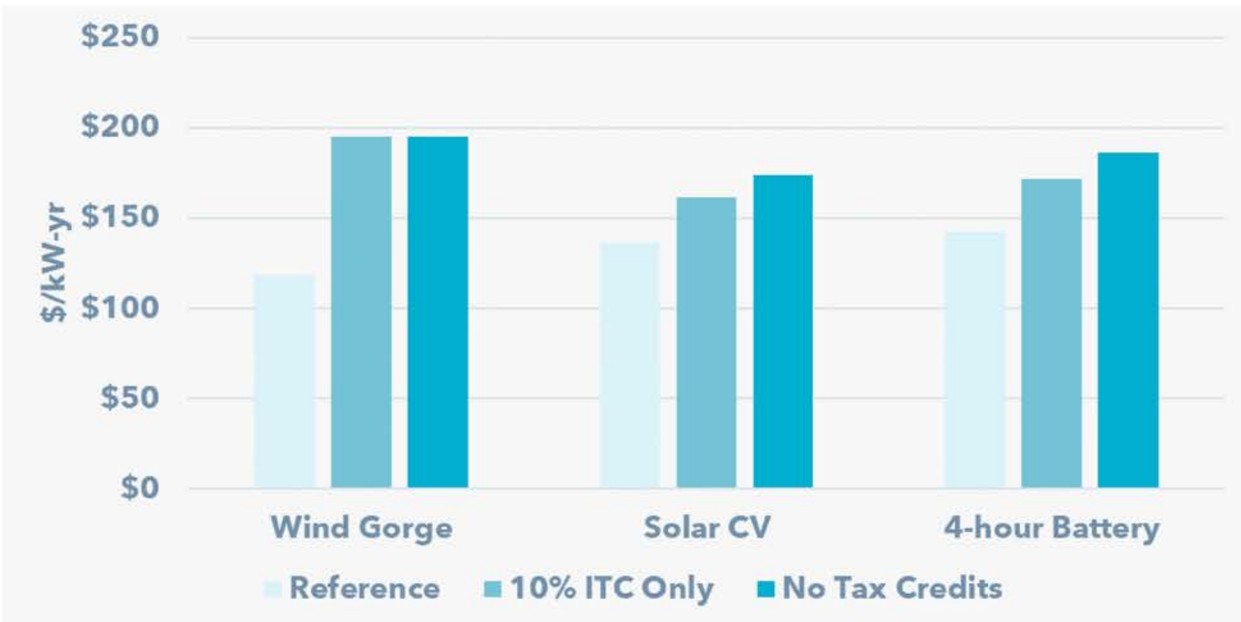
[104] https://www.boem.gov/newsroom/press-releases/boem-postpones-oregon-offshore-wind-energy-auction.
[105] Tax credits are discussed in Section 2.1 and 8.1.6 of the 2023 CEP/IRP (see pages 42 and 173).

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.

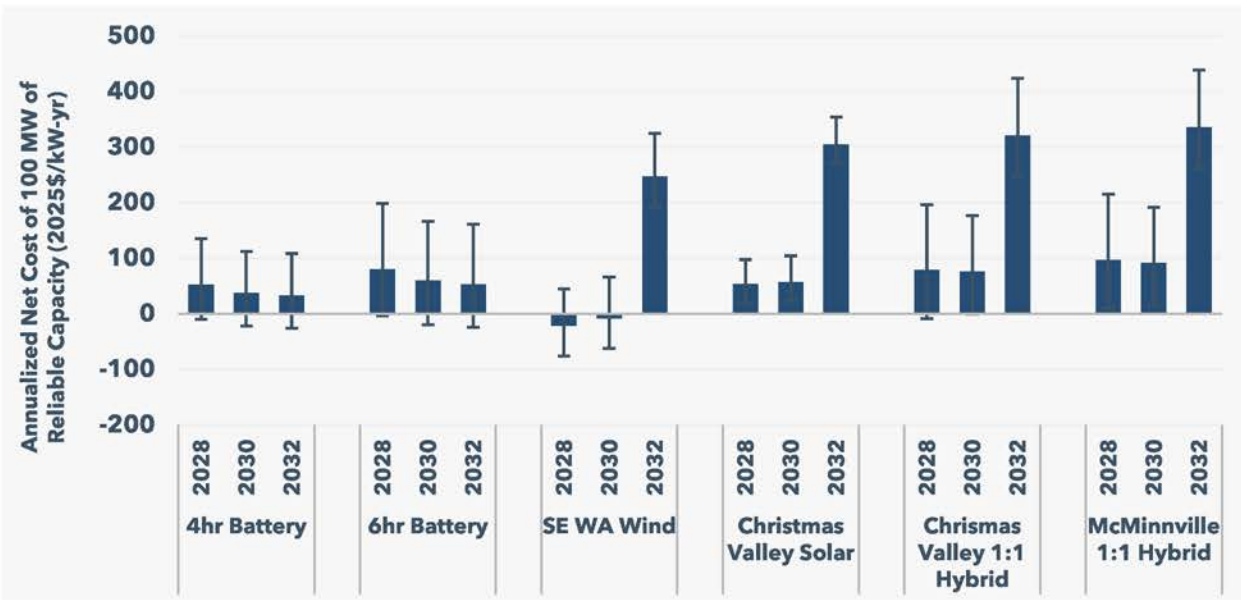
#### 5.1.9.1 Net cost – capacity resources

**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.

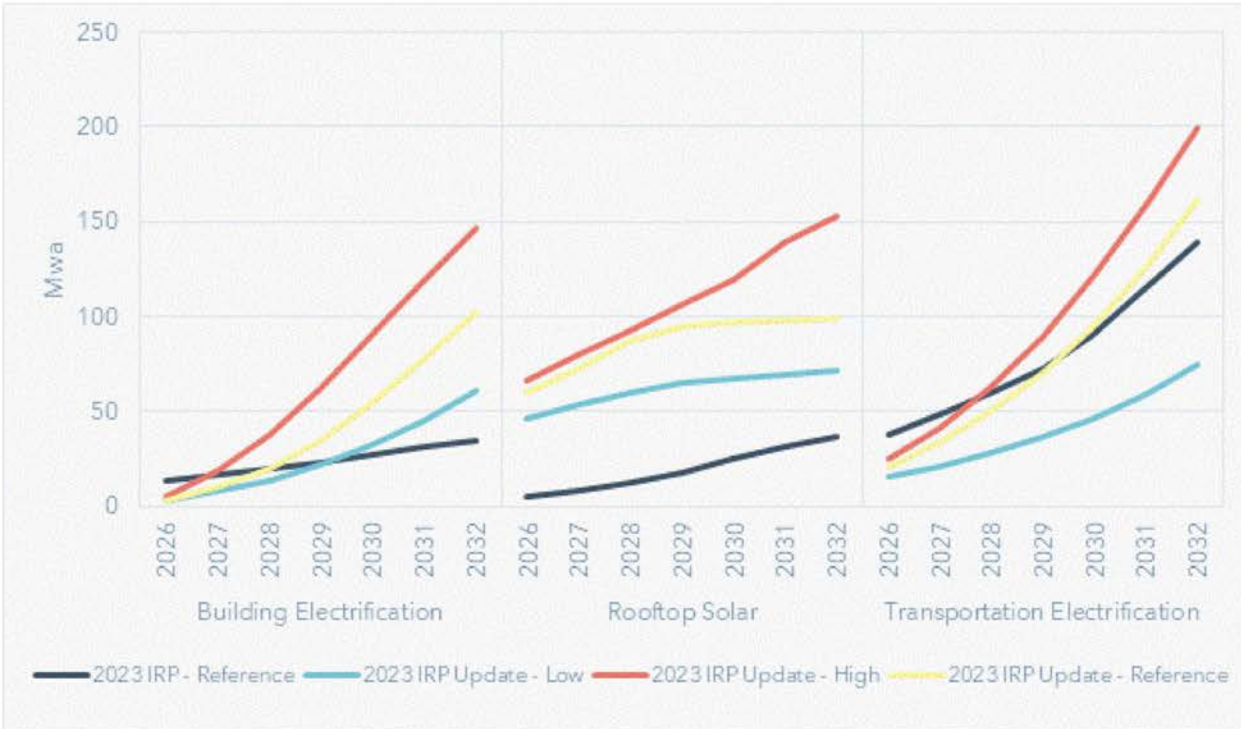
AdopDER calculates cost-effectiveness metrics for each demand response resource and modeling of these resources in the IRP is handled in distinct ways depending on whether a resource is deemed to be cost-effective, or non-cost-effective, in AdopDER. Cost-effective measures are assumed to be adopted, 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

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[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.

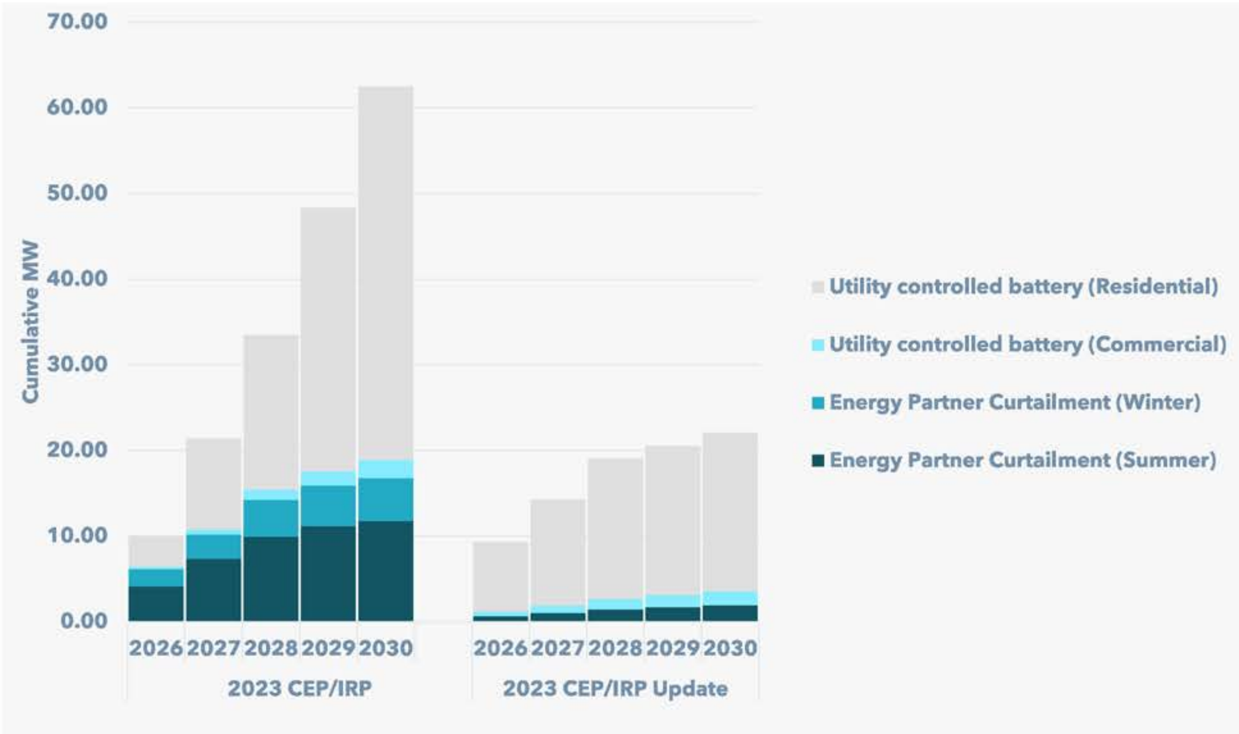
[117] PGE Rate Schedule 200

[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)

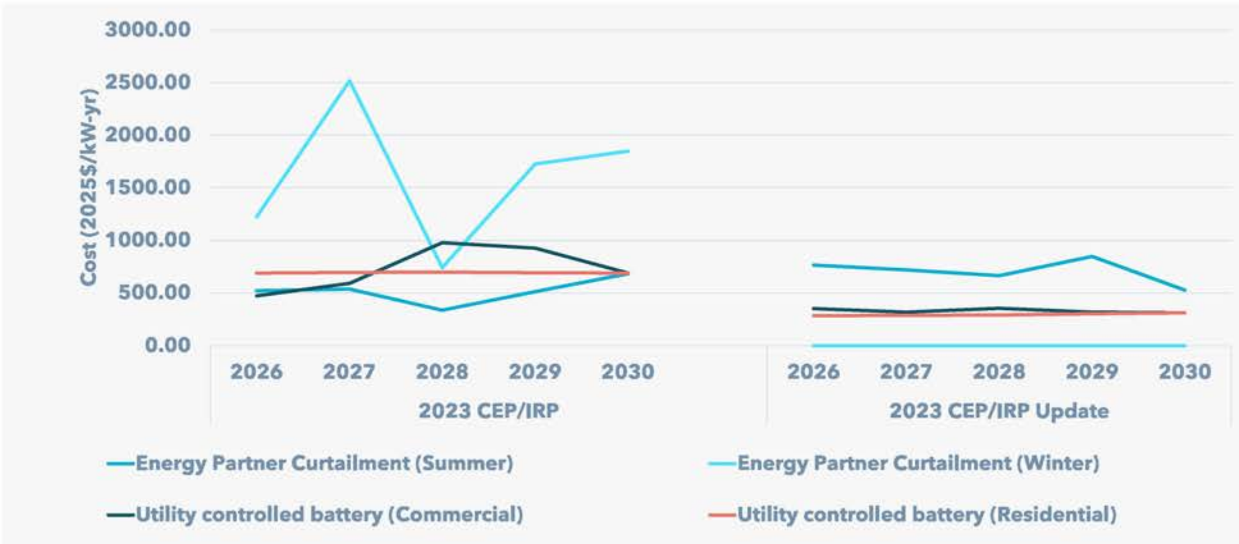
AdopDER run. Further, capacity from winter NCE Energy Partner Curtailment resources is non-existent in the 2024 AdopDER run, as the smart thermostat and cold storage curtailment programs previously bundled within are now considered cost-effective.

**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

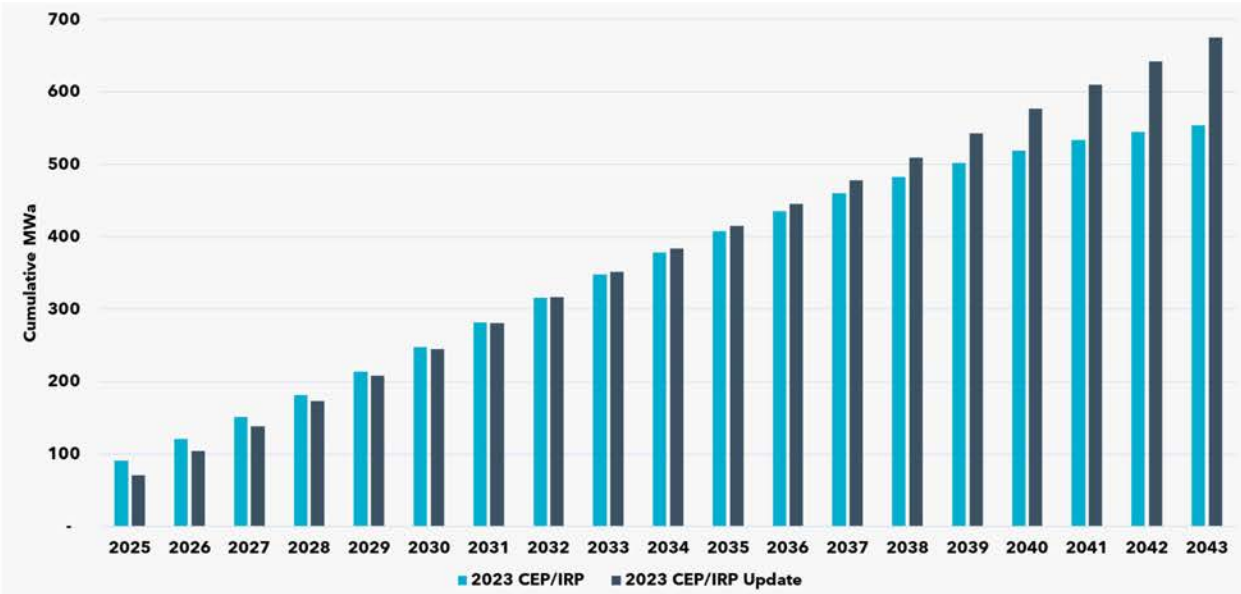
PGE receives a list of Cost-Effective (CE) Energy Efficiency measures that the ETO has found to pass its cost-effectiveness screening. The screening involves using a benefit-cost ratio to determine if the present value of benefits is equal to or exceeds the present value of the costs of the measure being 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

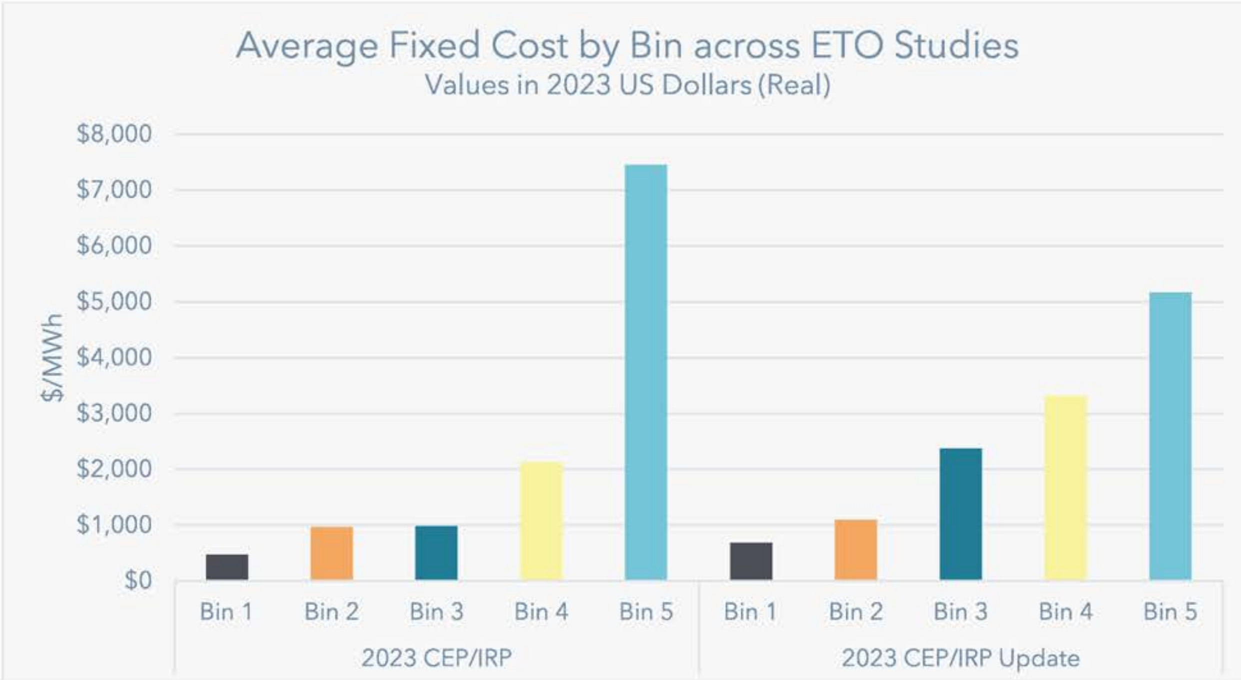
The total cumulative megawatt-average of NCE energy efficiency expected by 2030 changes little between the 2023 CEP/IRP and the 2023 CEP/IRP Update, falling from 70 megawatt-average to 68.1 megawatt-average across all five bins, as summarized in **Figure 52**. The bin sizes differ between filings as 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.

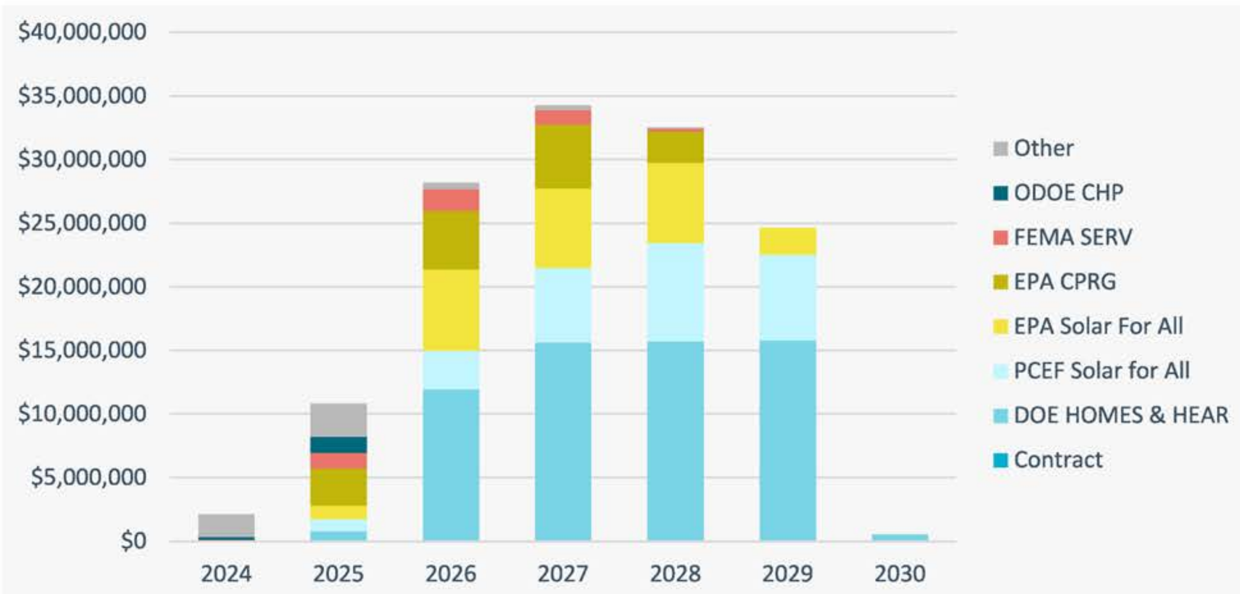
**Guiding principles for leveraging funds**

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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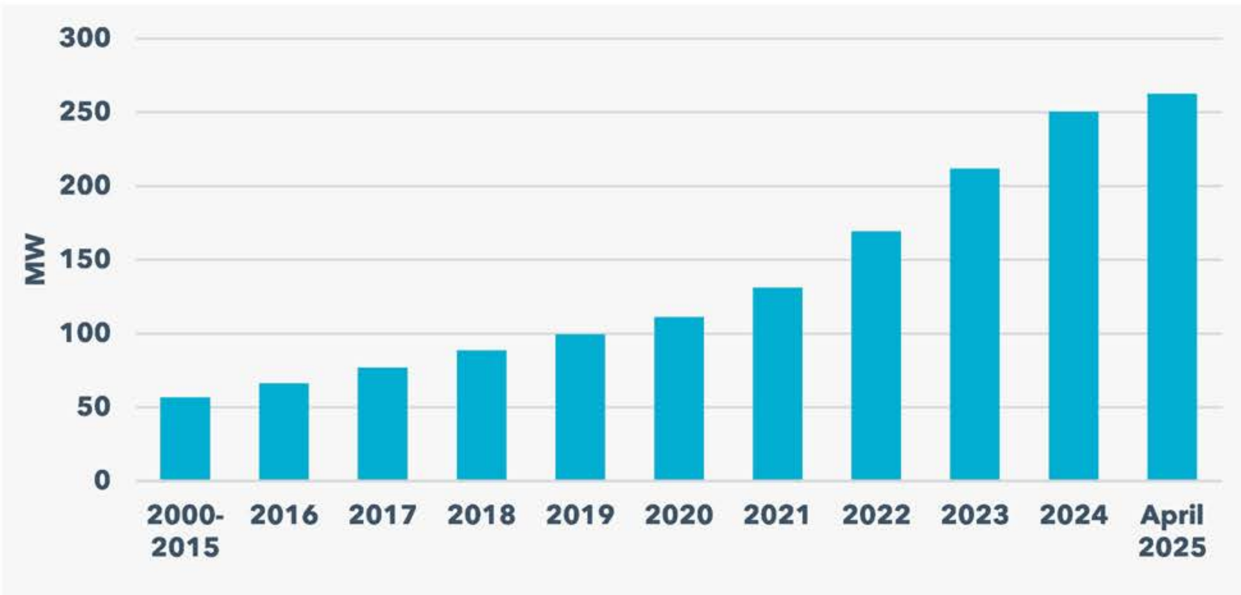
[123] While SSR resources can be CBRE's, they are not required to provide the community benefits that distinguish CBRE's from other small-scale resources. The SSR proxy resource therefore does not include any assumption of provision of community benefits beyond what would be provided by larger utility-scale 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]

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[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.

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[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**<br>**Economic Impacts** | Economic development, increased access to jobs, economic well-being, increased productivity |
| **pCBI 2**<br>**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**<br>**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**<br>**Resilience / Reliability** | Improved grid resiliency; increased resilience/reliability in environmental justice communities, including reduced recovery time and frequency of outages |
| **pCBI 5**<br>**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)**

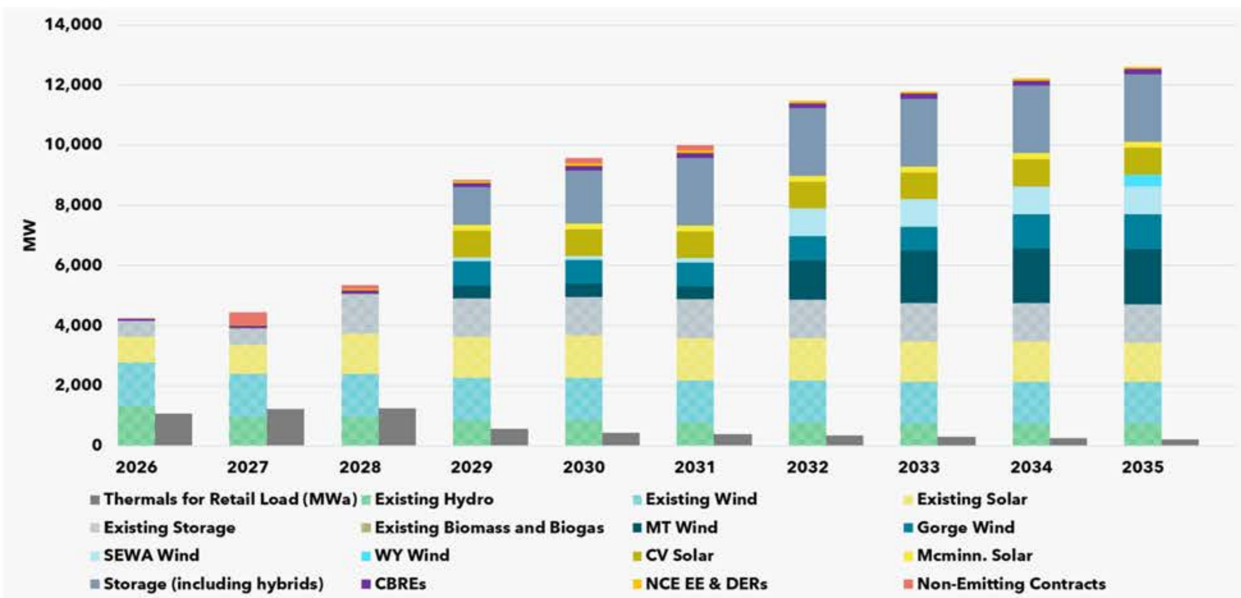
| Resource | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 |
|---|---|---|---|---|---|---|---|---|
| **Wind** | 1362 | 2989 | 3420 | 3844 | 4274 | 4761 | 5352 | 5947 |
| **Solar (including hybrids)** | 1089 | 1089 | 1089 | 1089 | 1089 | 1089 | 1089 | 1089 |
| **Storage (including hybrids)** | 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

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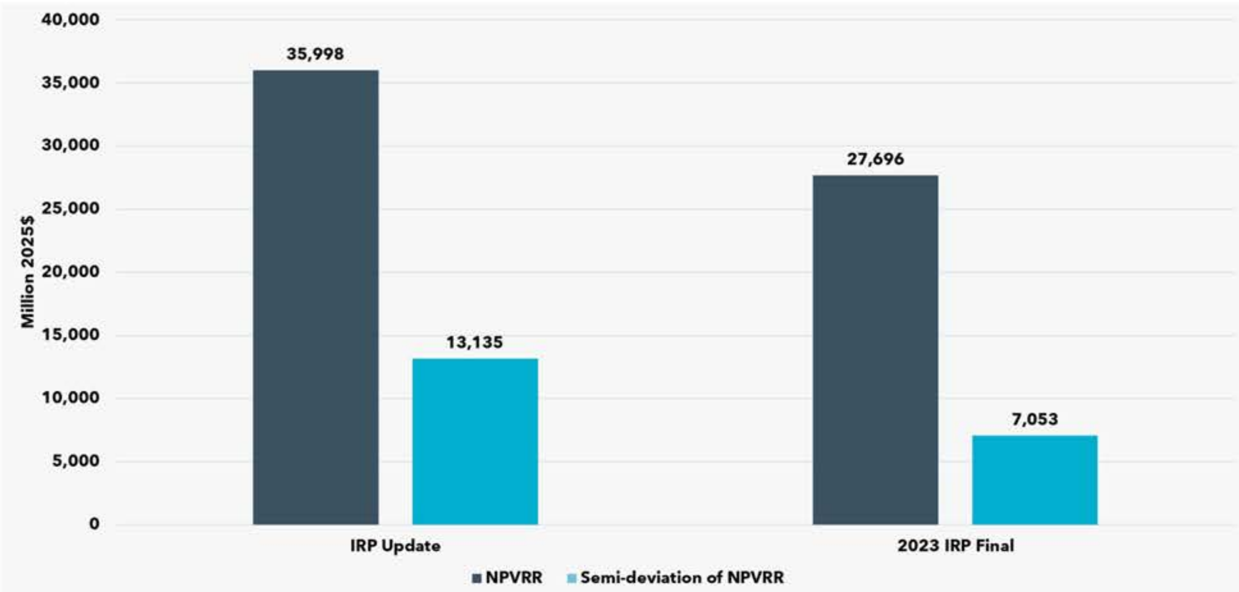
140 Existing resource quantities include 2023 RFP Proxy.
141 The final Preferred Portfolio from the 2023 CEP/IRP was published in PGE's response to Staff Round 2 Comments. Available here: https://edocs.puc.state.or.us/efdocs/HAC/lc80hac154444.pdf
142 Portfolio costs in the 2023 CEP/IRP were reported 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**.

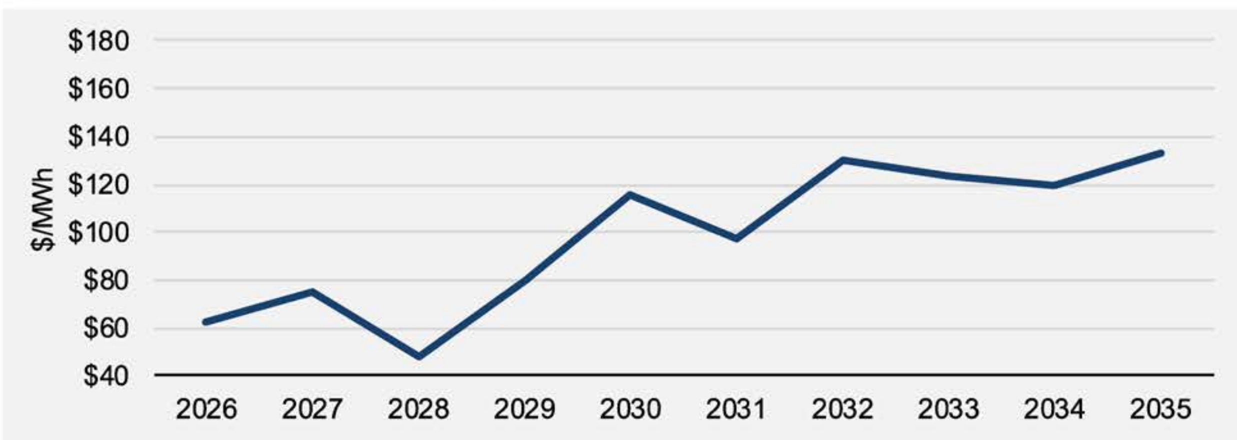
The model incorporates the impact of market sales on an annual basis and can evaluate different combinations of ownership structures and tax incentives for each portfolio.[143] Market purchases and thermal sales are calculated on an annual basis within the Intermediary GHG (IGHG) model and imported to 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**.

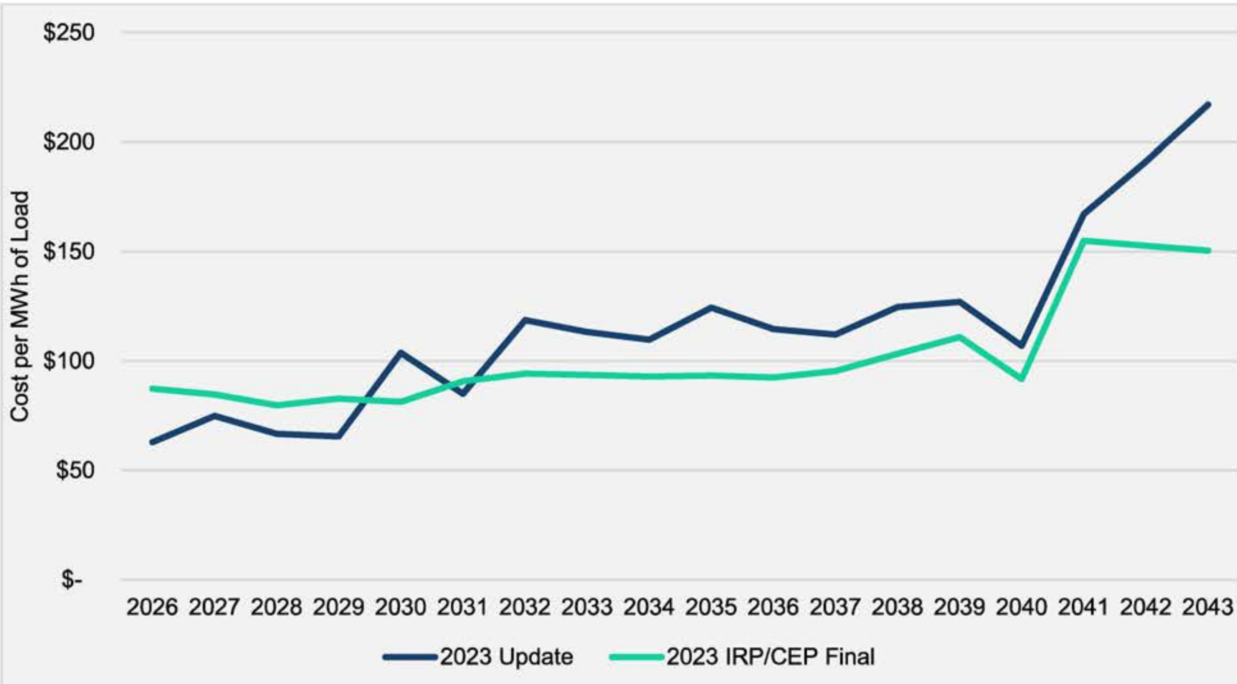
The price impacts can still be indicative for evaluating options to decarbonize reliably. Through an extensive analysis of resource additions amongst a variety of portfolios, PGE finds that while the incremental resource additions included in these estimates represent the least cost and risk manner to 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.

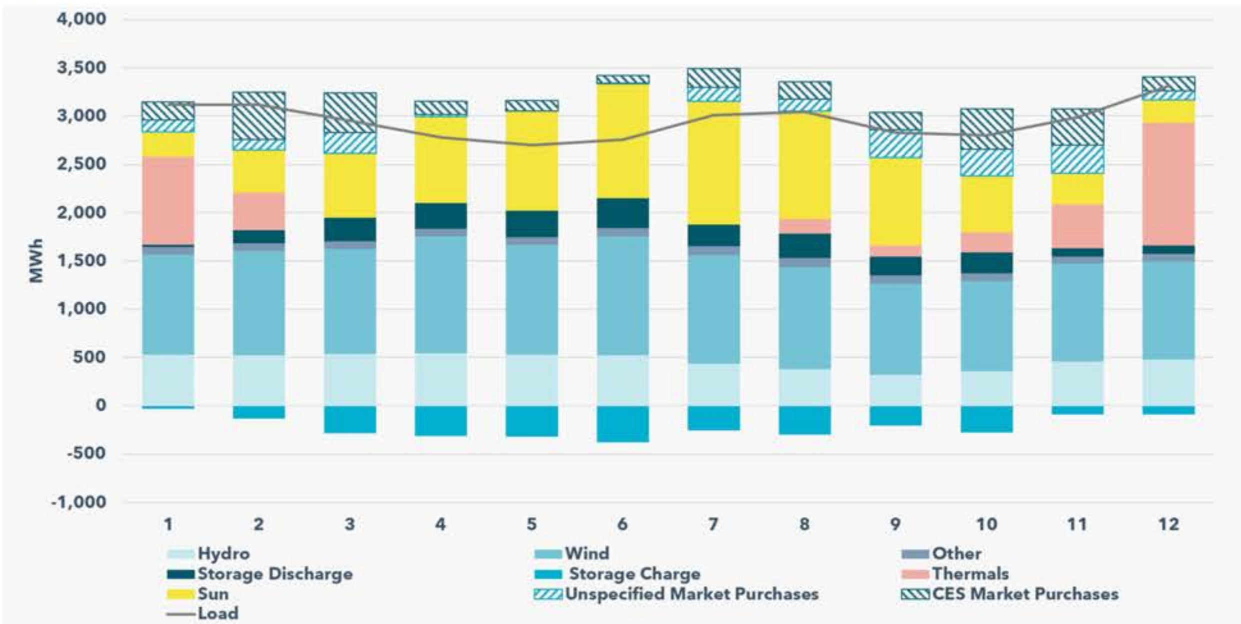
The following sections provide the results of this hourly mPZM analysis. First, a summary of monthly results demonstrates how emissions compliance is achieved; next, assumptions regarding market availability are detailed; generation from thermal resources are summarized; finally, example weeks in June 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

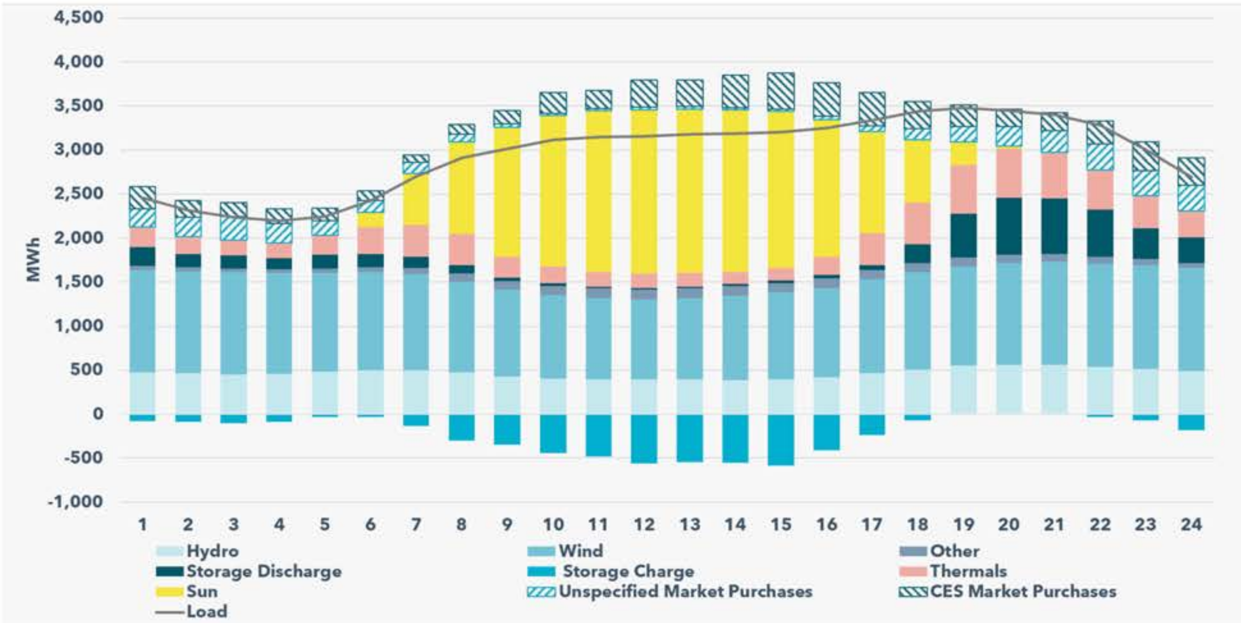
**Figure 61** demonstrates the composition of supply used to meet demand for each month in 2030. Thermal generation is concentrated in the winter when non-emitting energy is scarce. Storage charging and discharging occurs in the spring, when storage opportunities to levelize net demand across the day 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**

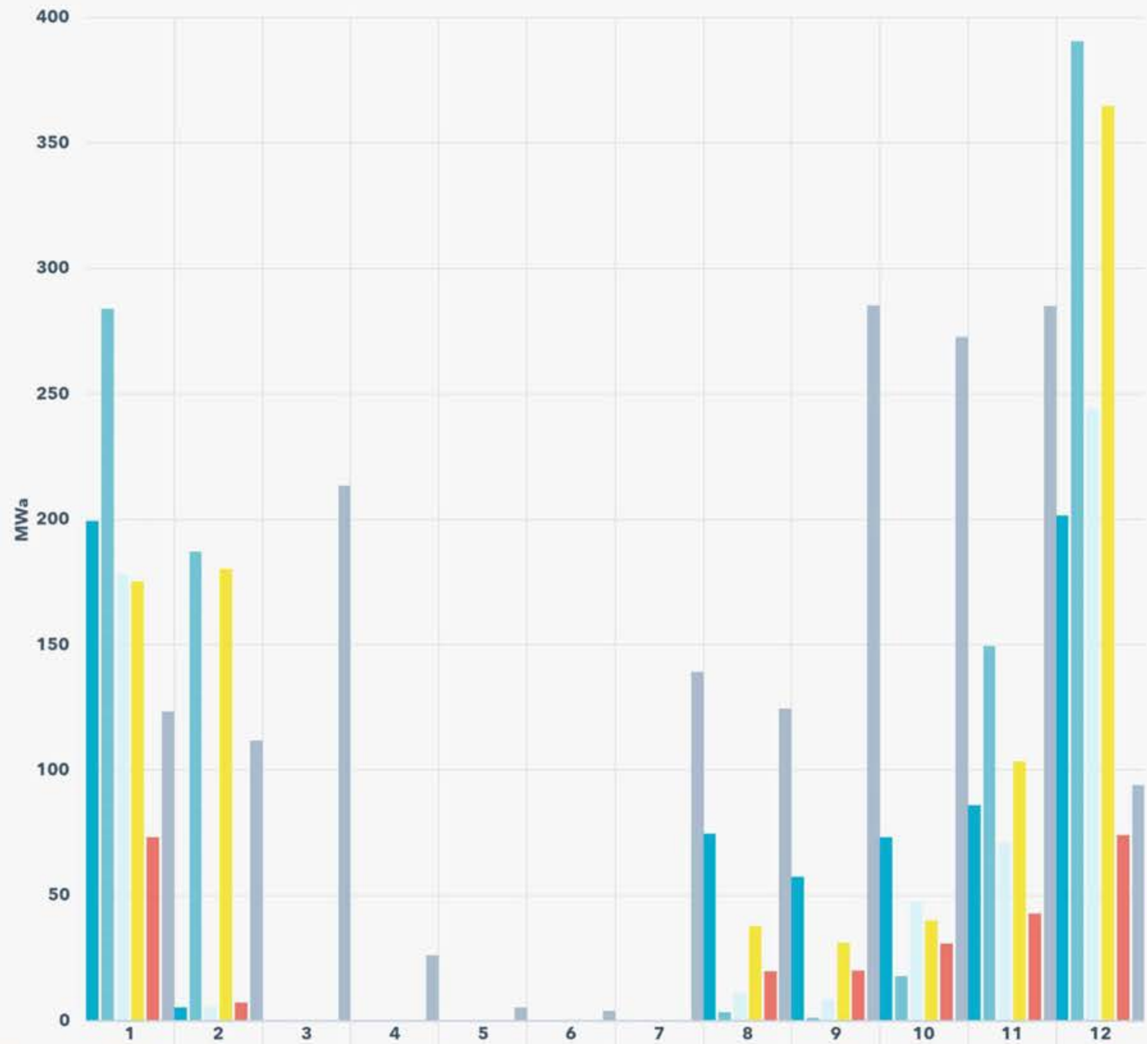

**Figure 64** shows the timing of both unspecified and clean energy surplus market purchases in the mPZM simulation; the price of clean energy surplus market purchases includes the additional premium for clean energy. The methodology first assigns unspecified market purchases to hours with the highest 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.

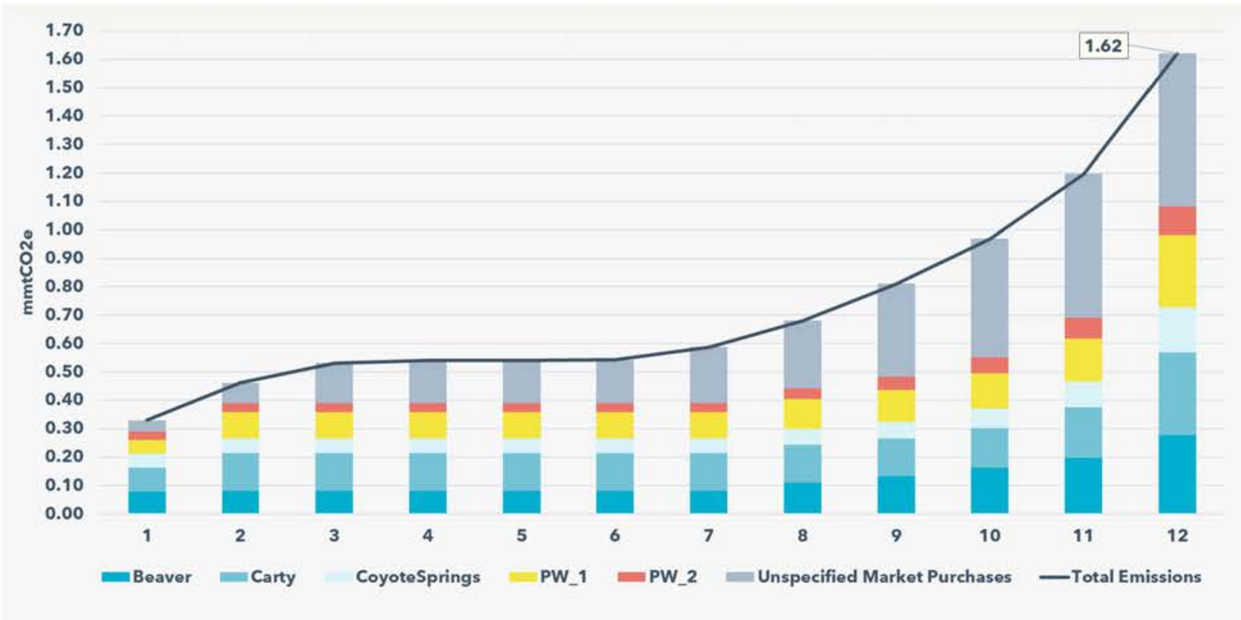
**Figure 65. Monthly generation (MWa) by emission source across 2030 forecast**




| | 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 $CO_2$ (mmt$CO_2$e). 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.

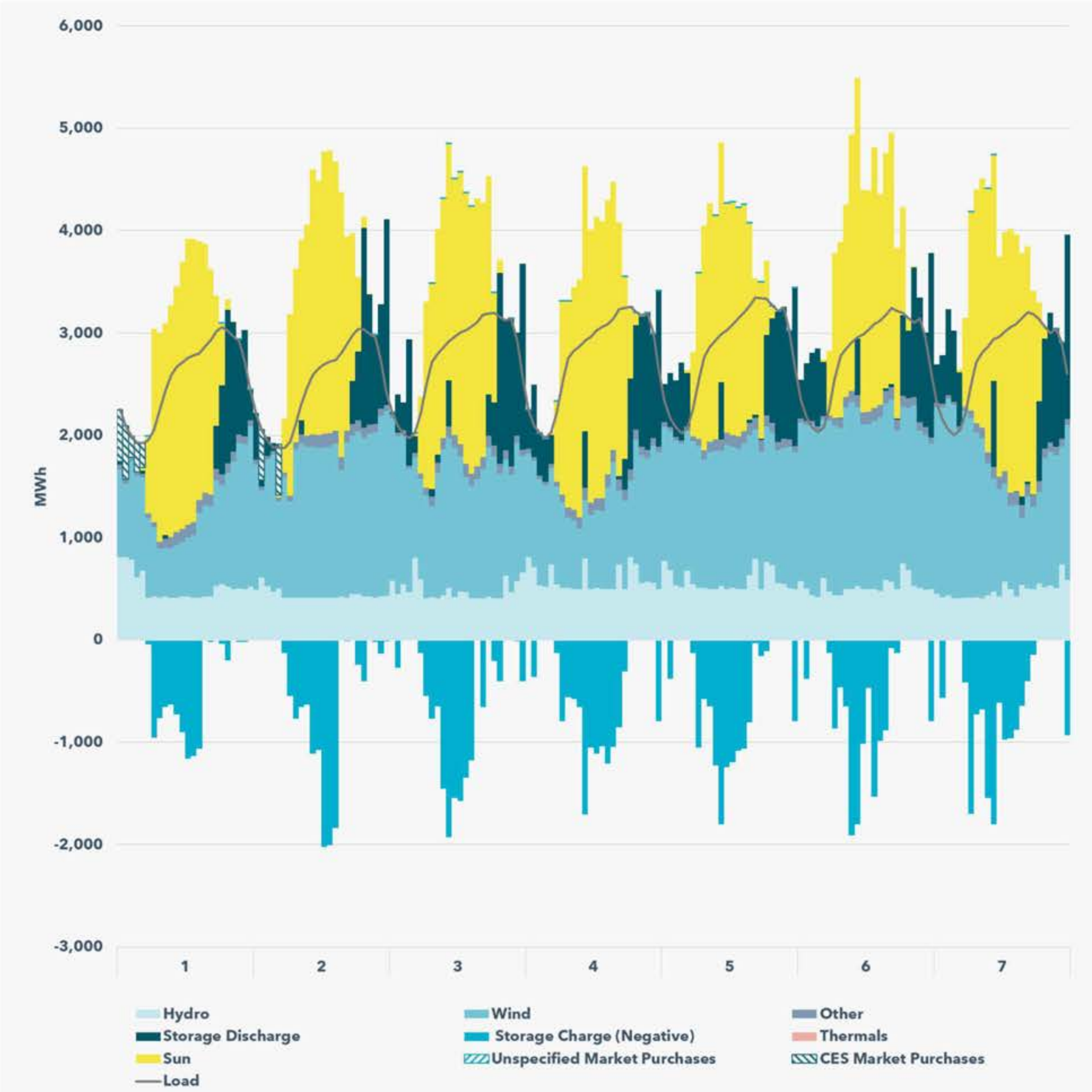
**Figure 66. mPZM simulated 2030 monthly cumulative emissions (mmtCO2e) by source**




### 6.2.2.1 Hourly generation snapshots

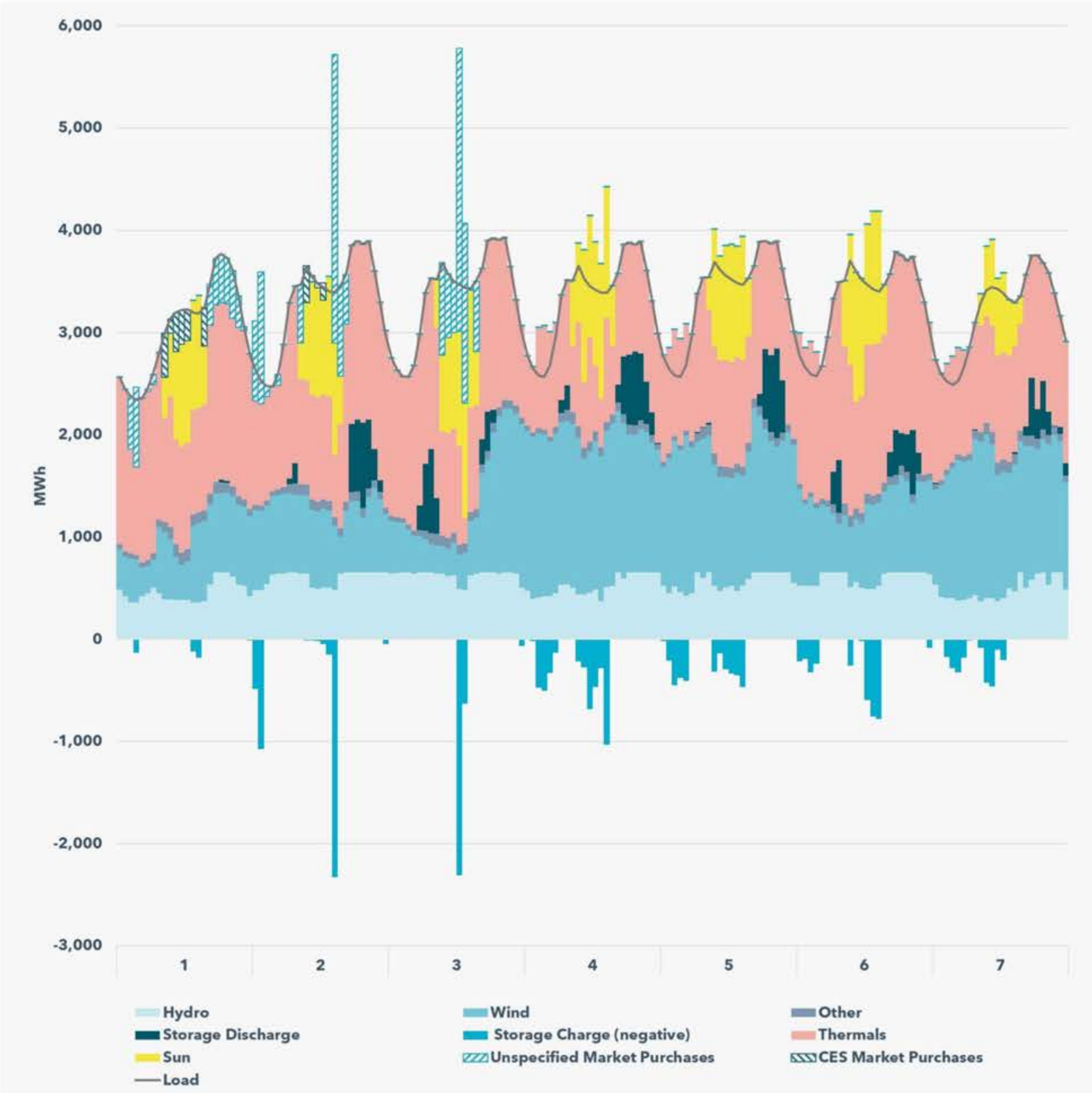
To demonstrate more granular representations of the mPZM results, sample weeks with hourly values by resource type are provided (**Figure 67**). The results include the first seven days of the month for June and December 2030 to demonstrate seasonal variation. June is punctuated by solar and wind generation 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**

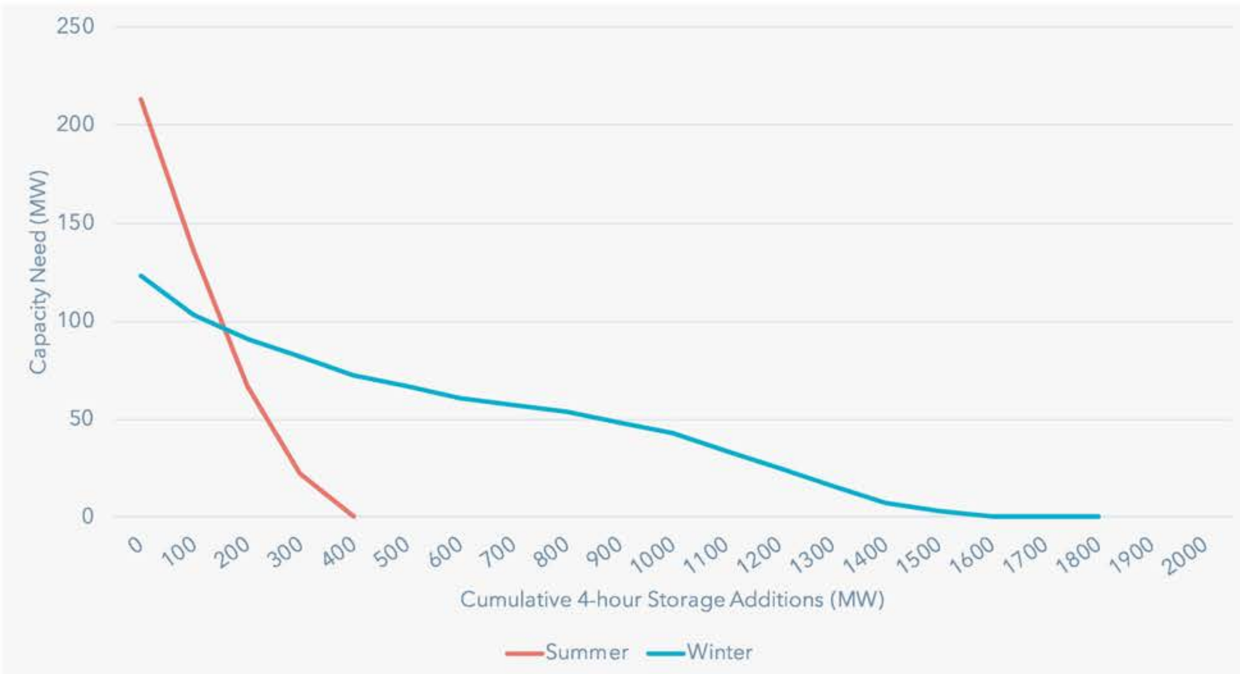
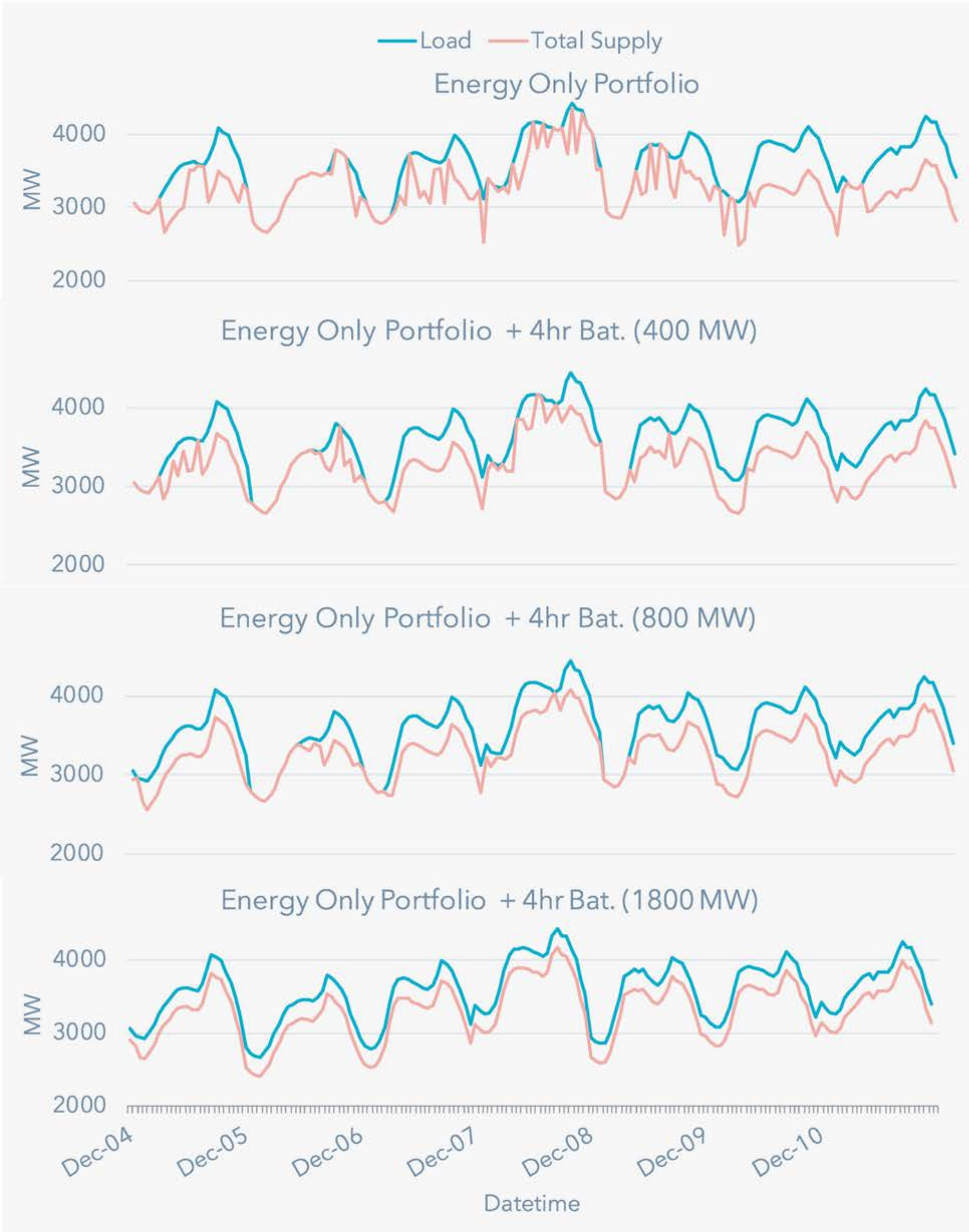



**Figure 70** shows a Sequoia simulation of load and supply during a week in December 2030. This image highlights the challenge of trying to meet load in winter with short-duration storage resources. The first panel shows load and total supply in the base system with the Energy Only Portfolio, where 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**



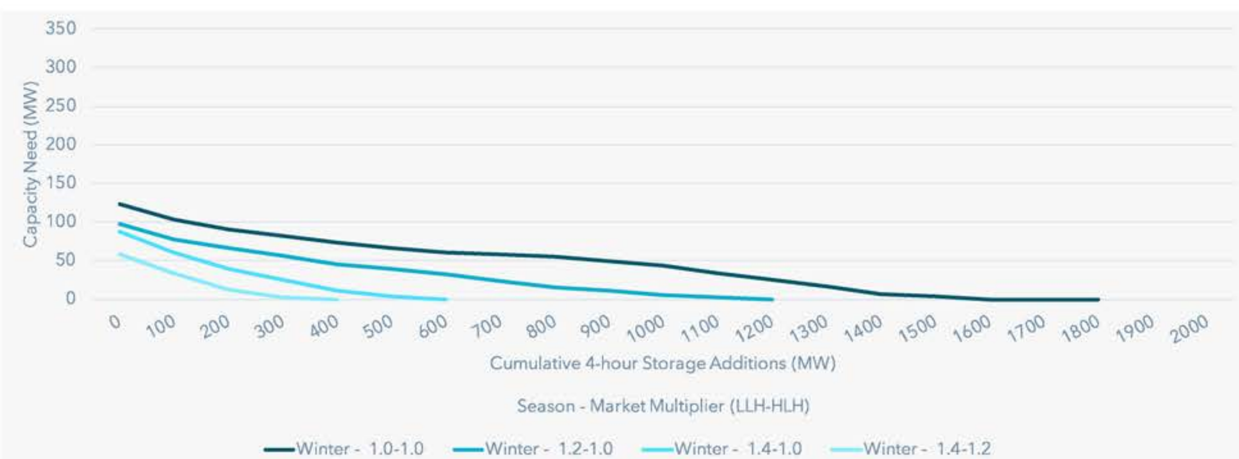

Previous regional resource adequacy studies have also reported on the challenges of meeting adequacy needs in the Pacific Northwest with short-duration storage. Energy and Environmental

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**

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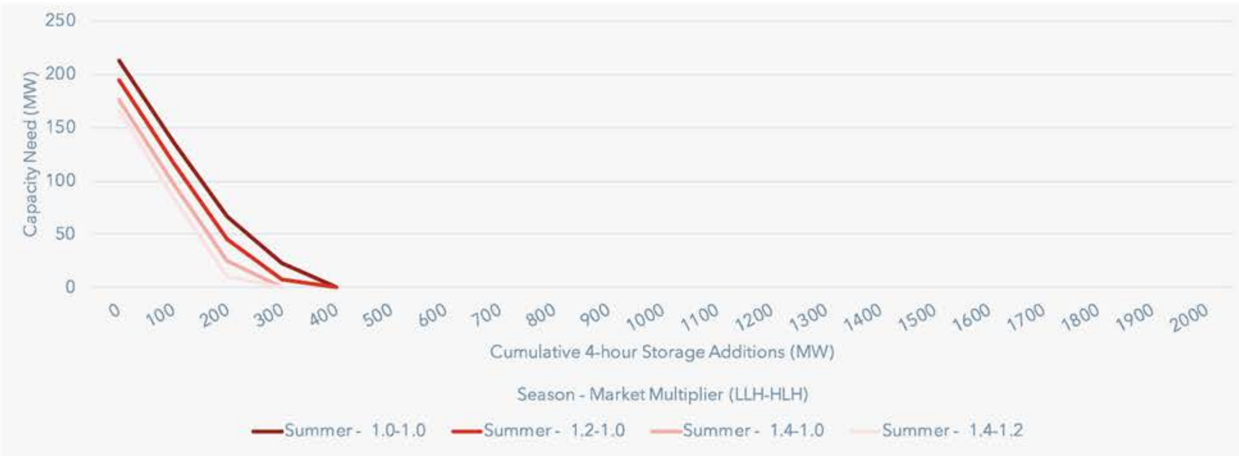
[150] Energy and Environmental Economics. 2019. Resource Adequacy in the Pacific Northwest. San Francisco, CA.

[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



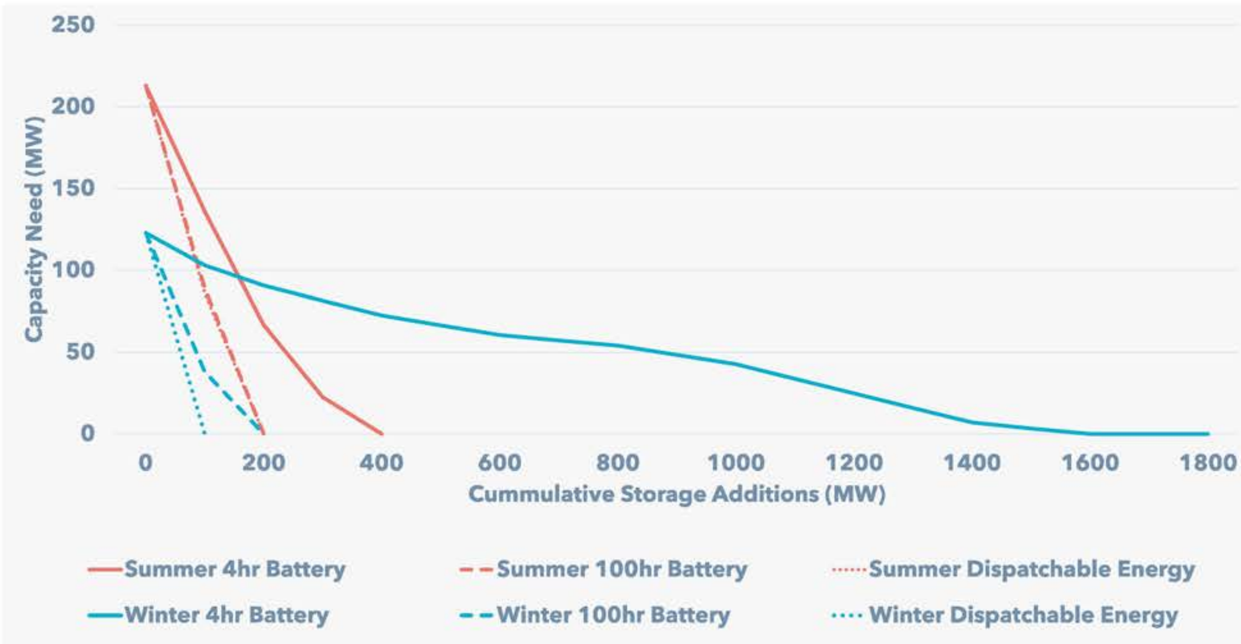

The above results highlight the sensitivity of the Preferred Portfolio to PGE's assumptions of access to regional markets. An estimated 66 percent of the 1800 MW of storage in the Preferred Portfolio is offset with approximately 400 MW of additional energy in LLH. Changing market access assumptions to 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)**

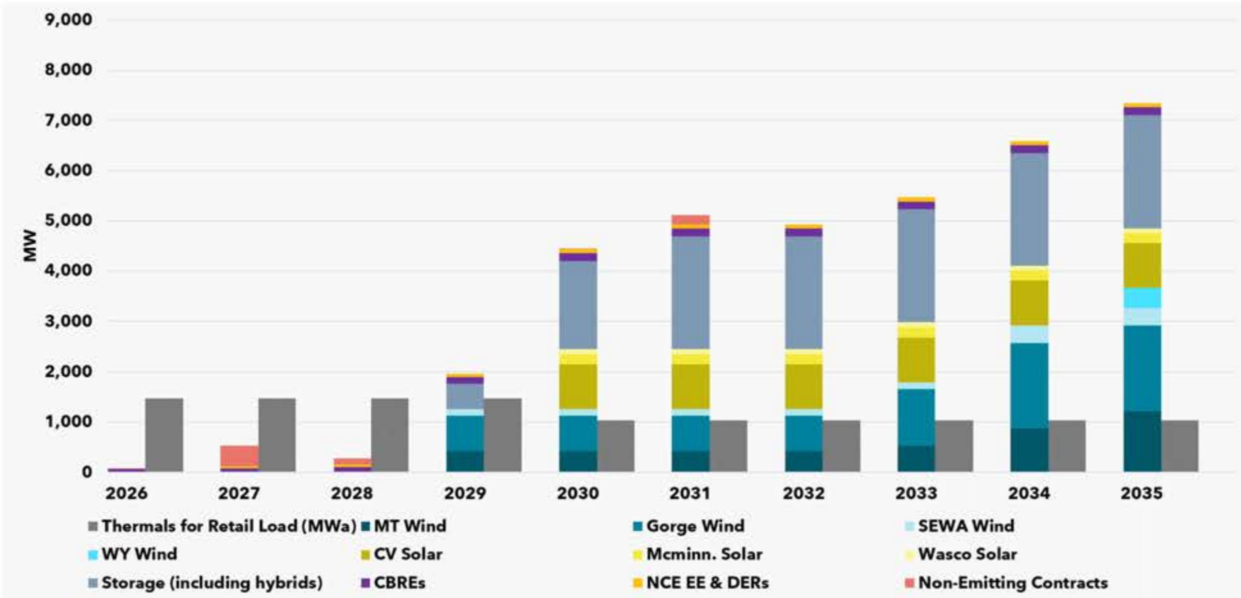
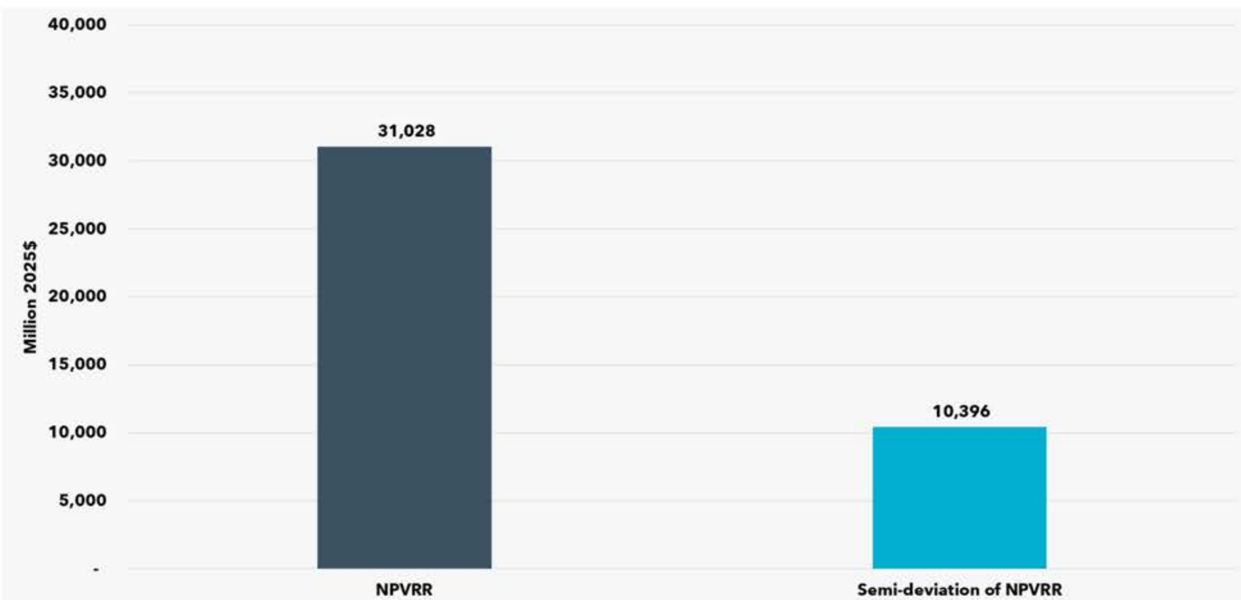



**Figure 74. Cost and Risk of Reliability Needs Only Scenario**

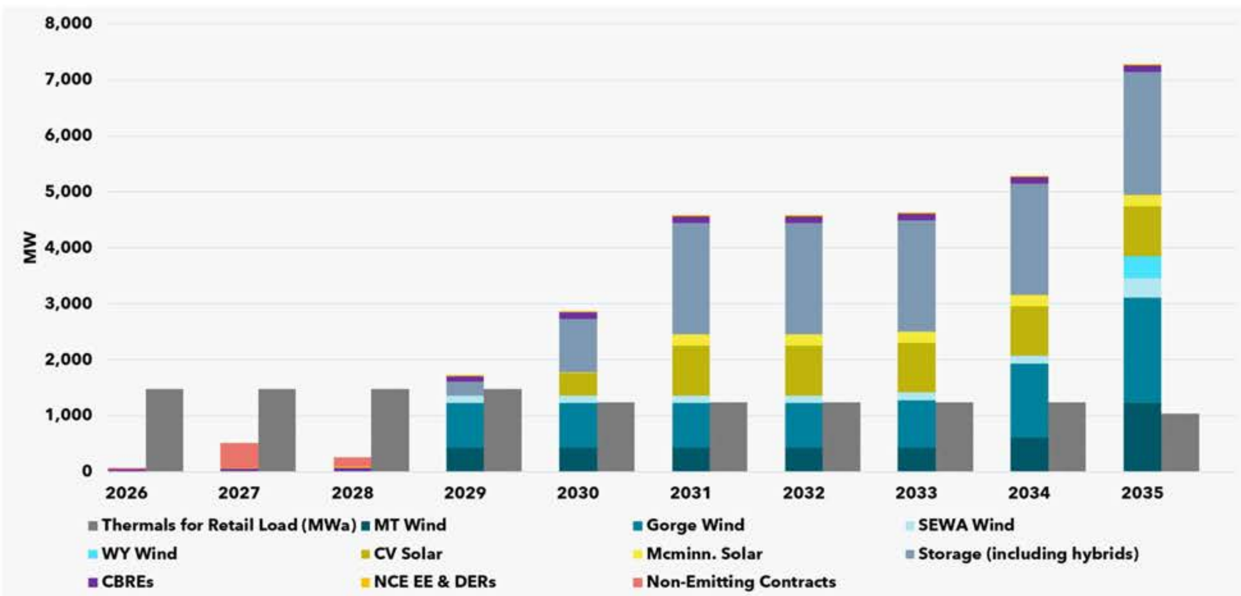



## 6.3.2 Further Reliability need sensitivities

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.

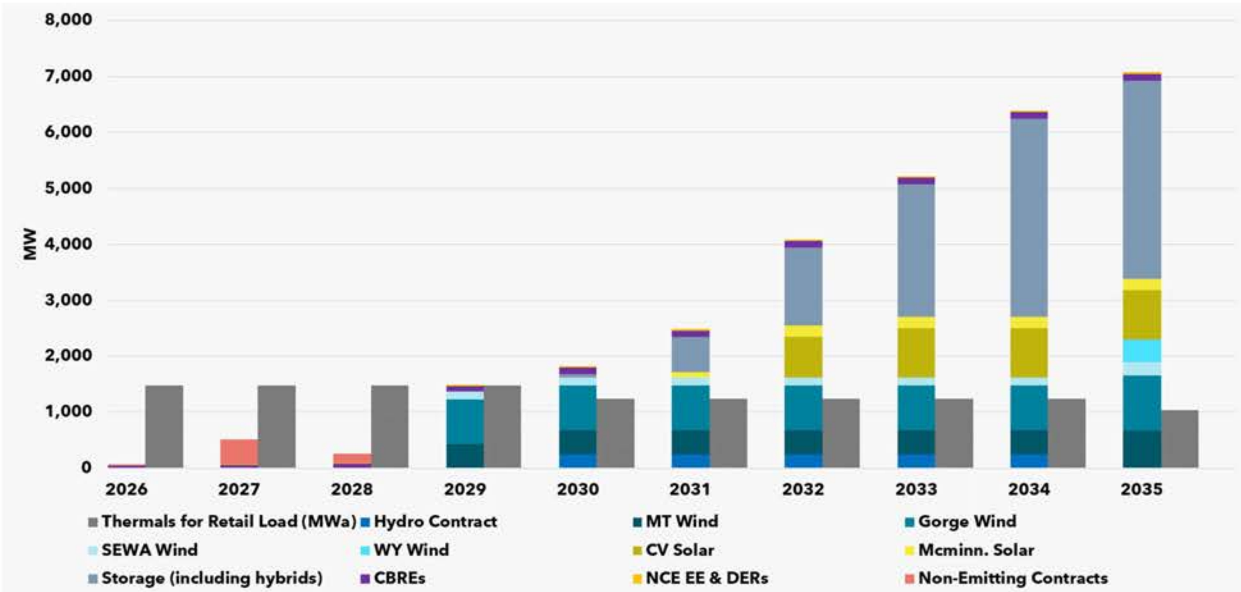
**Figure 75. Resource Additions for Dispatchable Emitting Contract Scenario**




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**

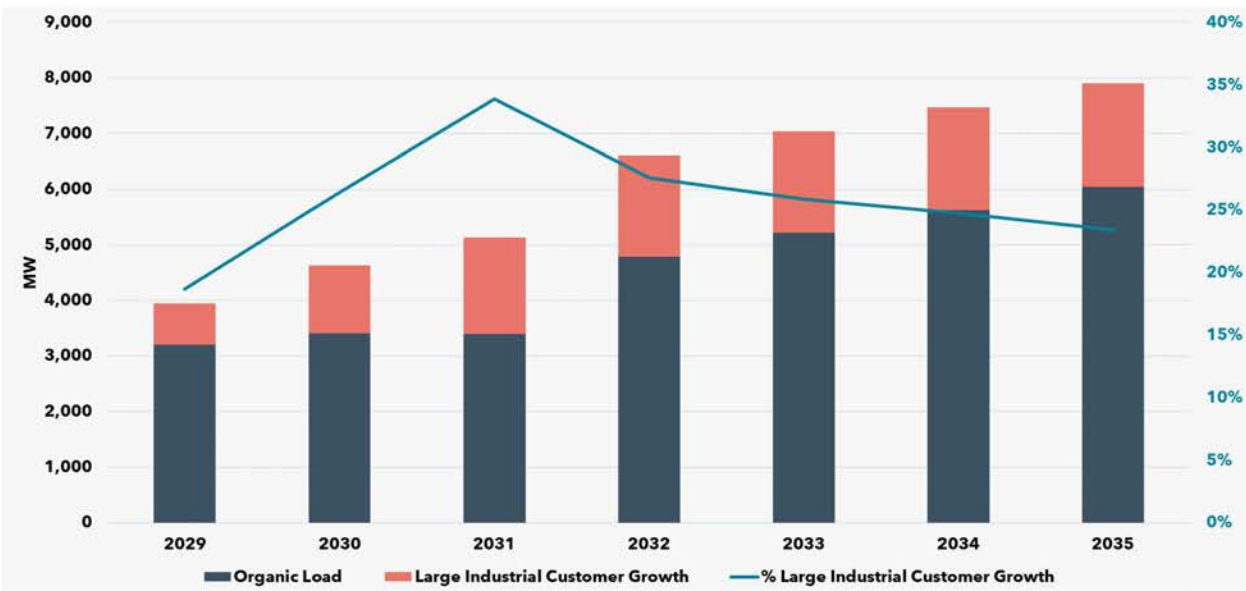



### 6.3.3 Large industrial customer growth

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**.

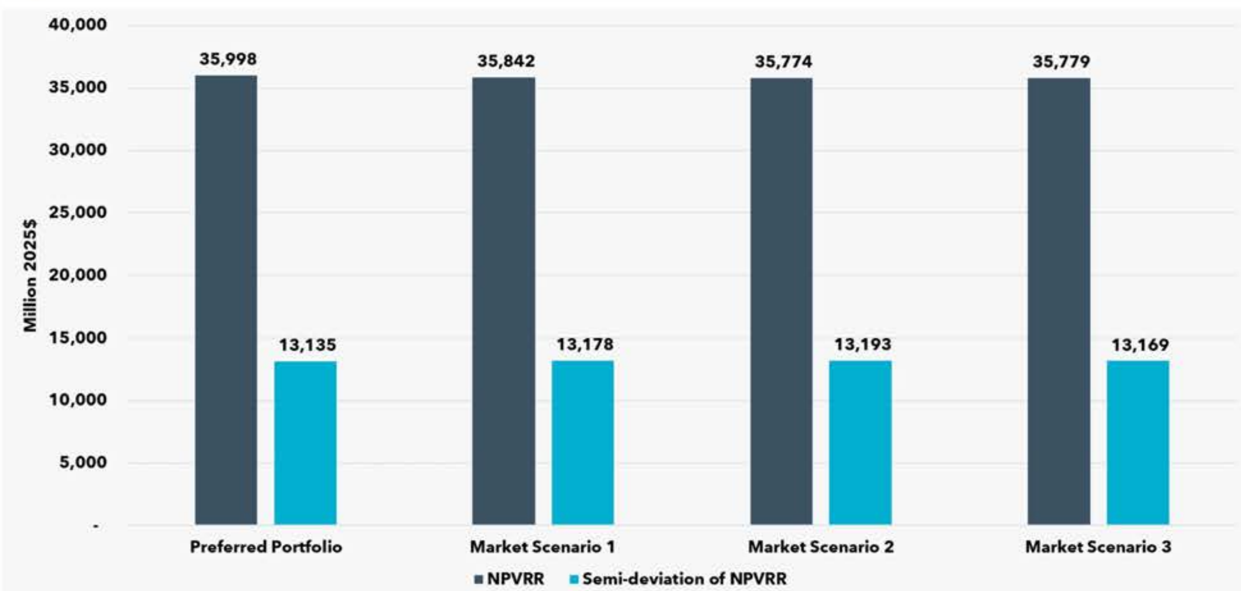
**Table 33. Market Scenarios**

| 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)**

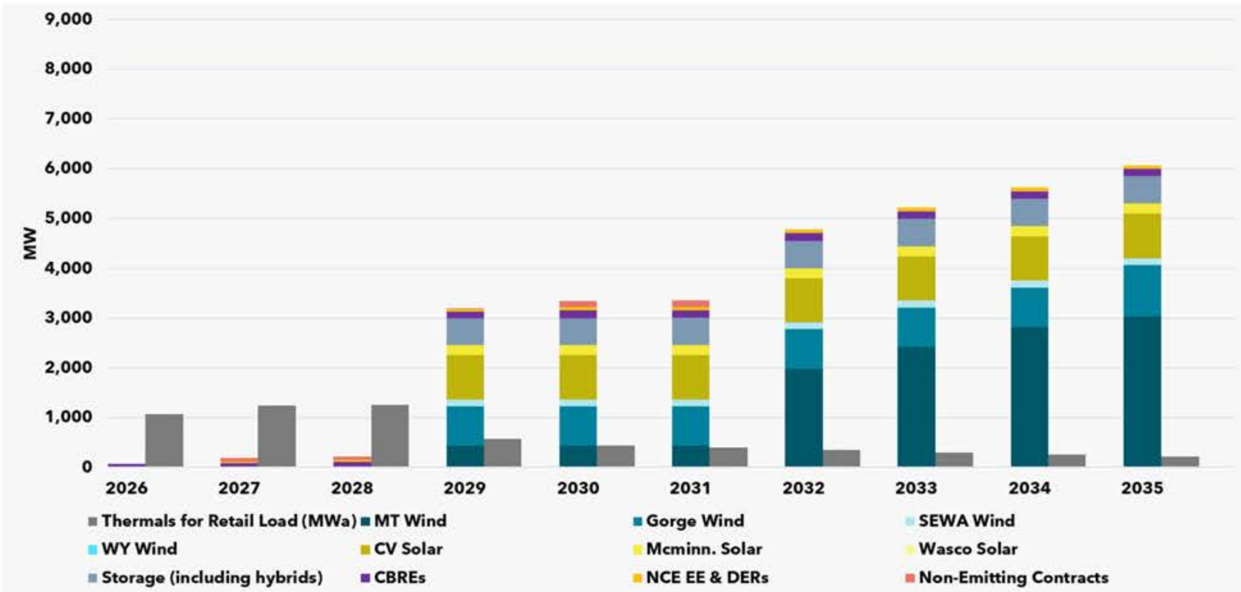
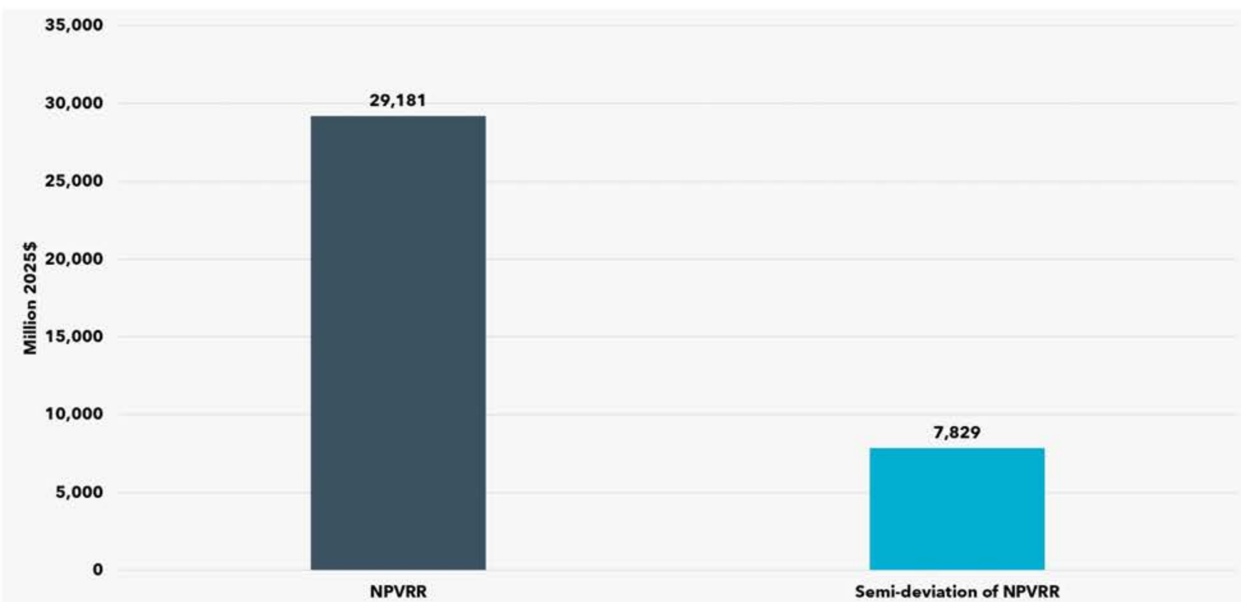



**Figure 80. Cost and Risk of State RA Requirements Scenario**

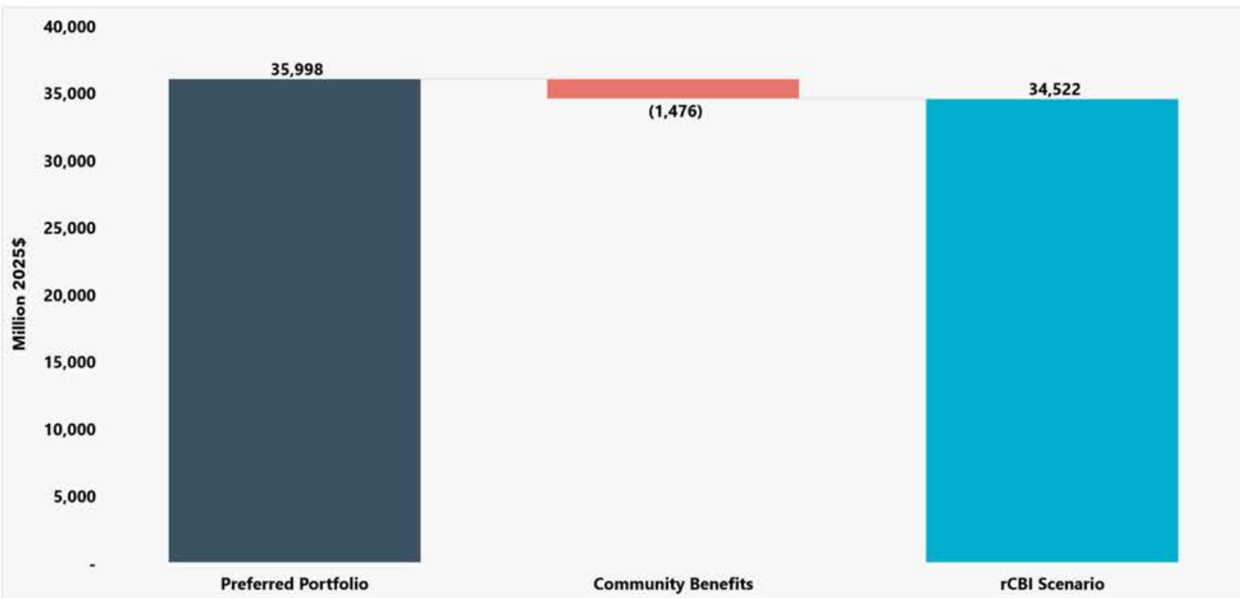



## 6.3.6 Resource Community Benefits Indicator (rCBI)

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

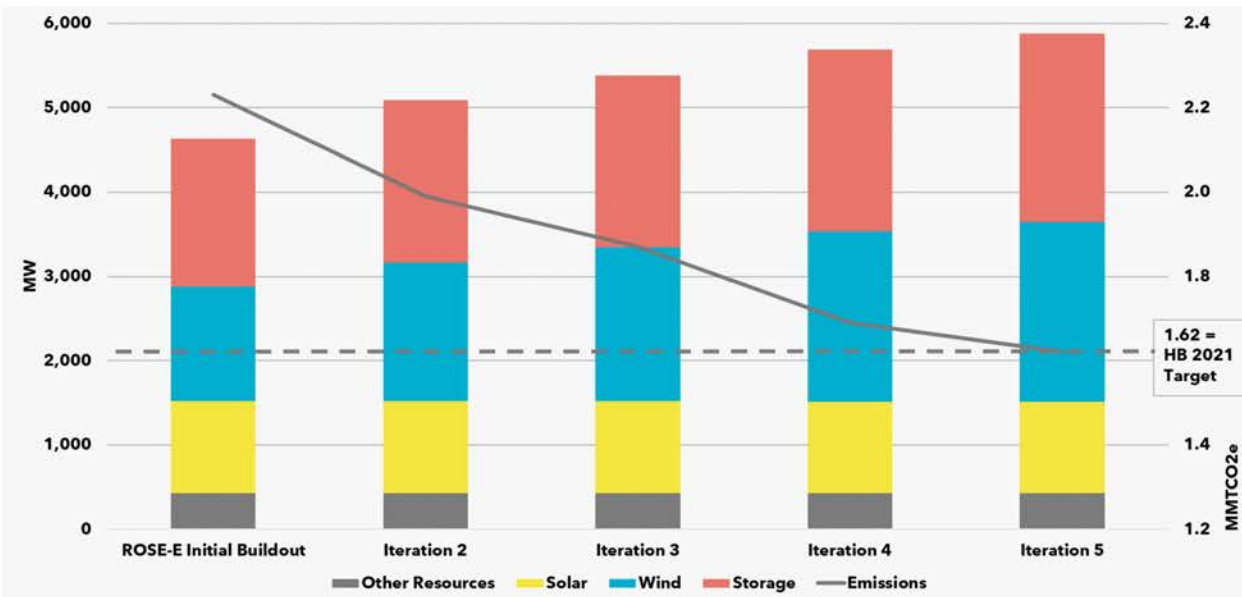
The 'Absence of Non-Emitting Market' scenario contemplates the quantity of resource additions that would be necessary to meet HB 2021 emissions targets using hourly energy accounting if PGE didn't have access to the non-emitting market energy that is available in the analysis reported in **Section 6.2.2 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).

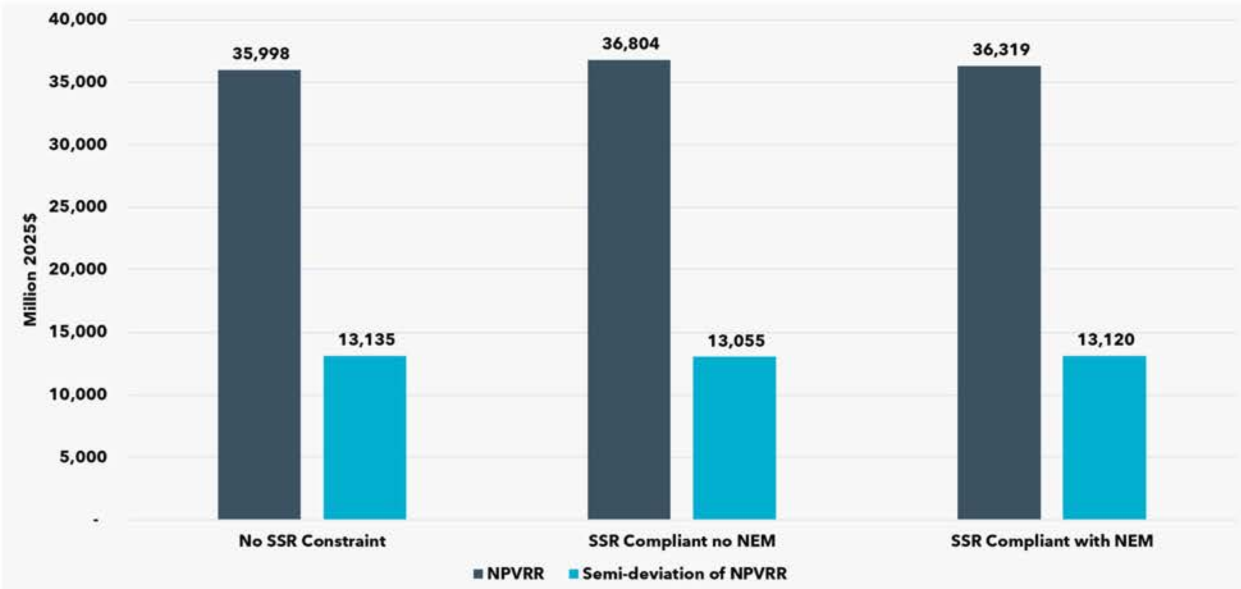
**Table 35. SSR Compliance Position, 2030**

| 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:

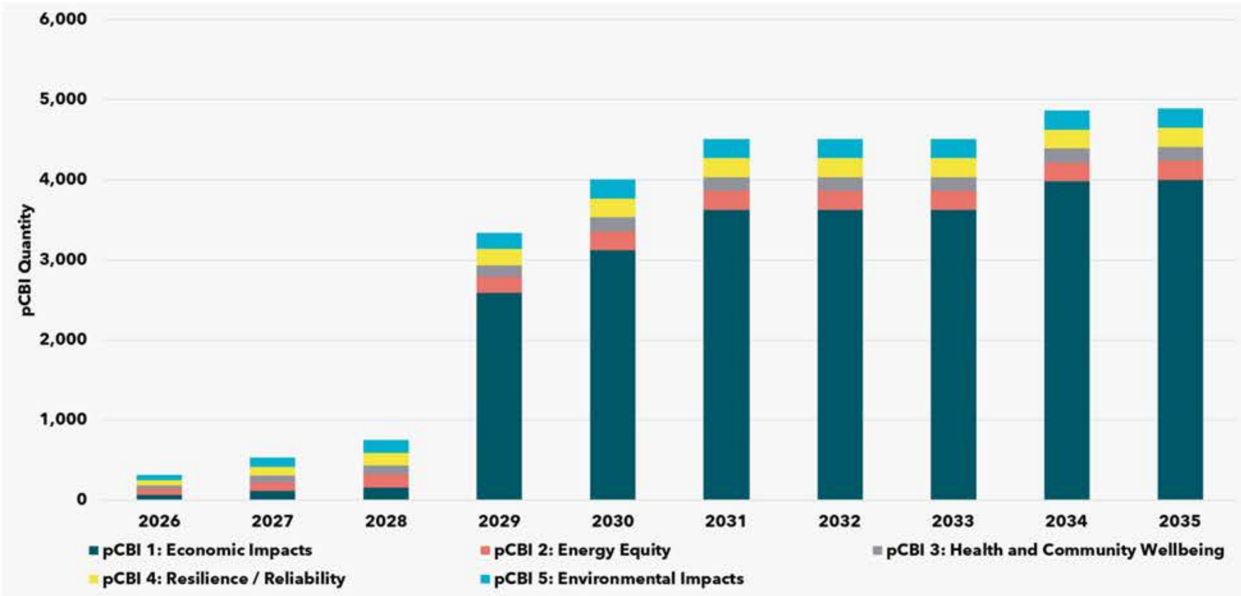
- CBRE Acquisition
- All-Source Energy and Capacity procurement, in which PGE encourages offers from SSRs

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

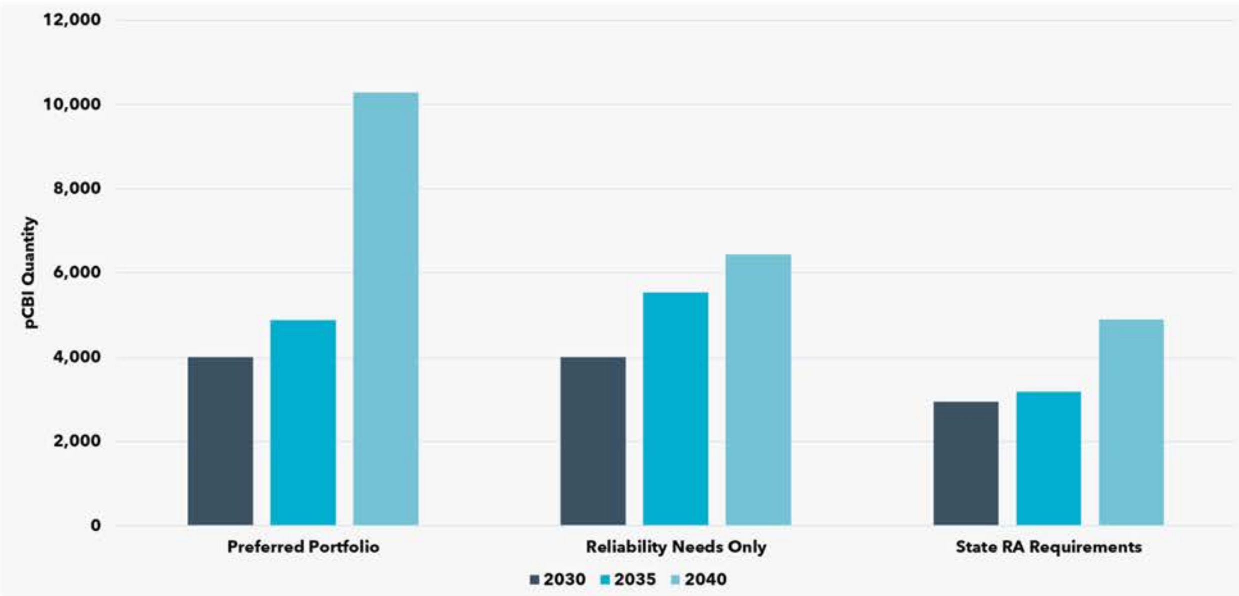
The cumulative quantity of each of the five pCBI scoring metrics through 2035 for the Preferred Portfolio are shown in **Figure 84**. A large increase in pCBIs generated can be seen in 2029, driven by the addition of substantial quantities of renewable resources, which generate economic community benefits (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**

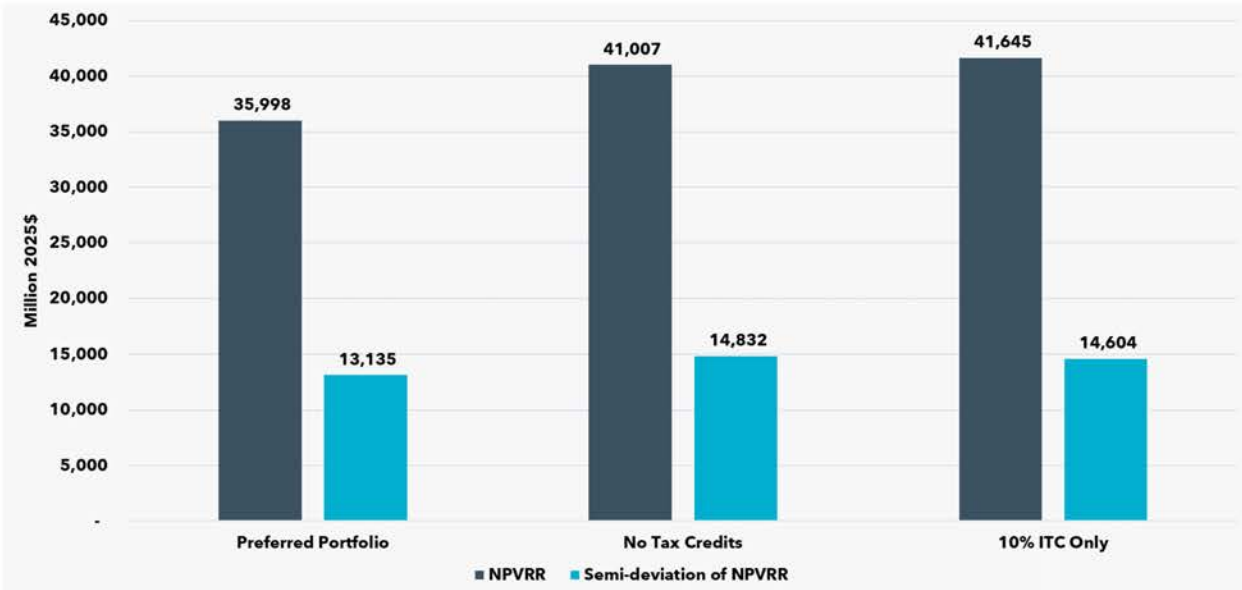



## 6.6 Federal tax credit availability scenarios

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)**

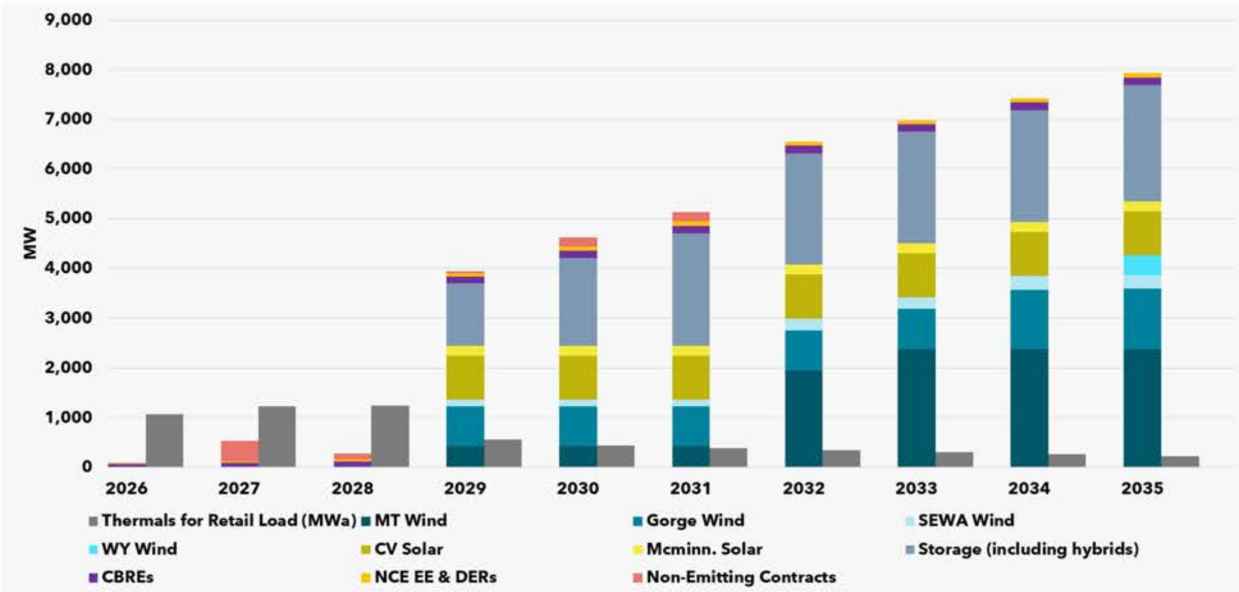



**Figure 88. Resource additions in no tax credits scenario (MW)**

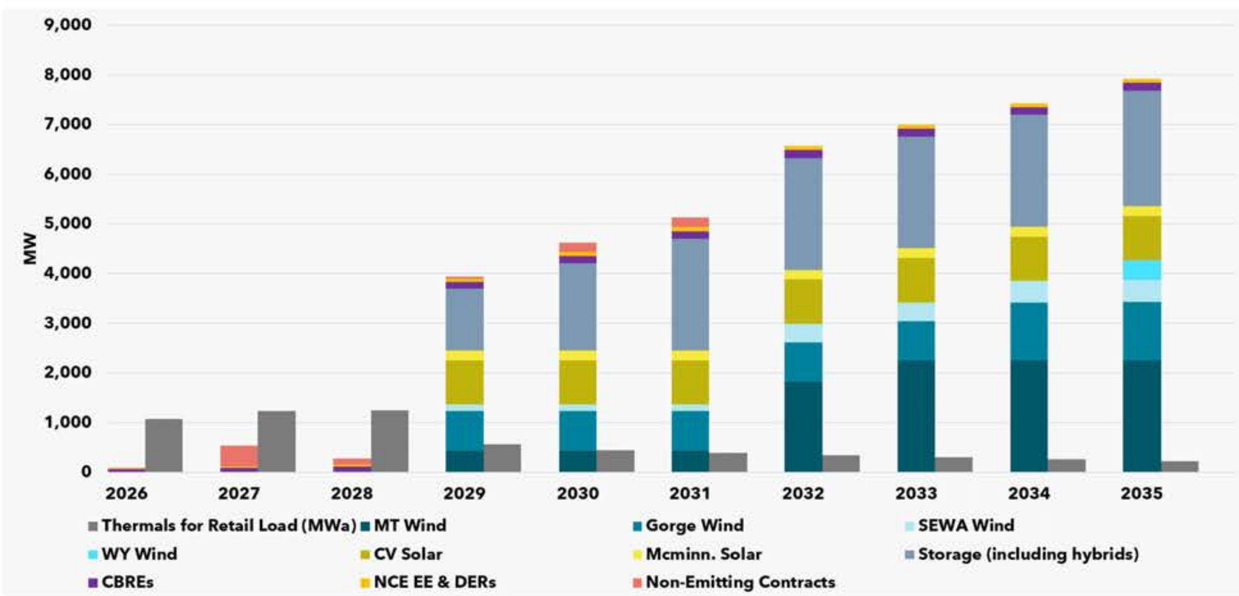



**Figure 89** below reflects the annual change in the revenue requirement under all three tax scenarios. This is the incremental cost excluding the baseline existing resource costs. Those costs in addition to the existing portfolio costs results in the portfolio generation cost per MWh shown in **Figure 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)**

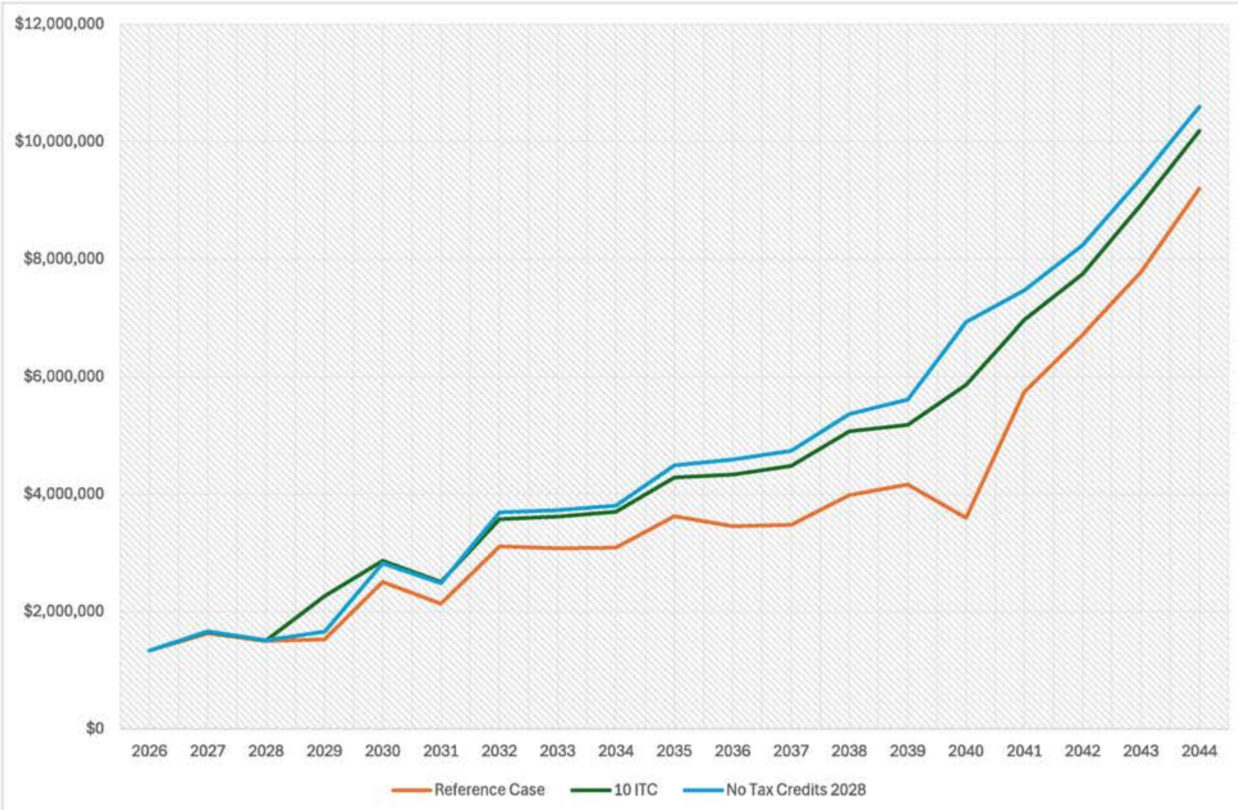
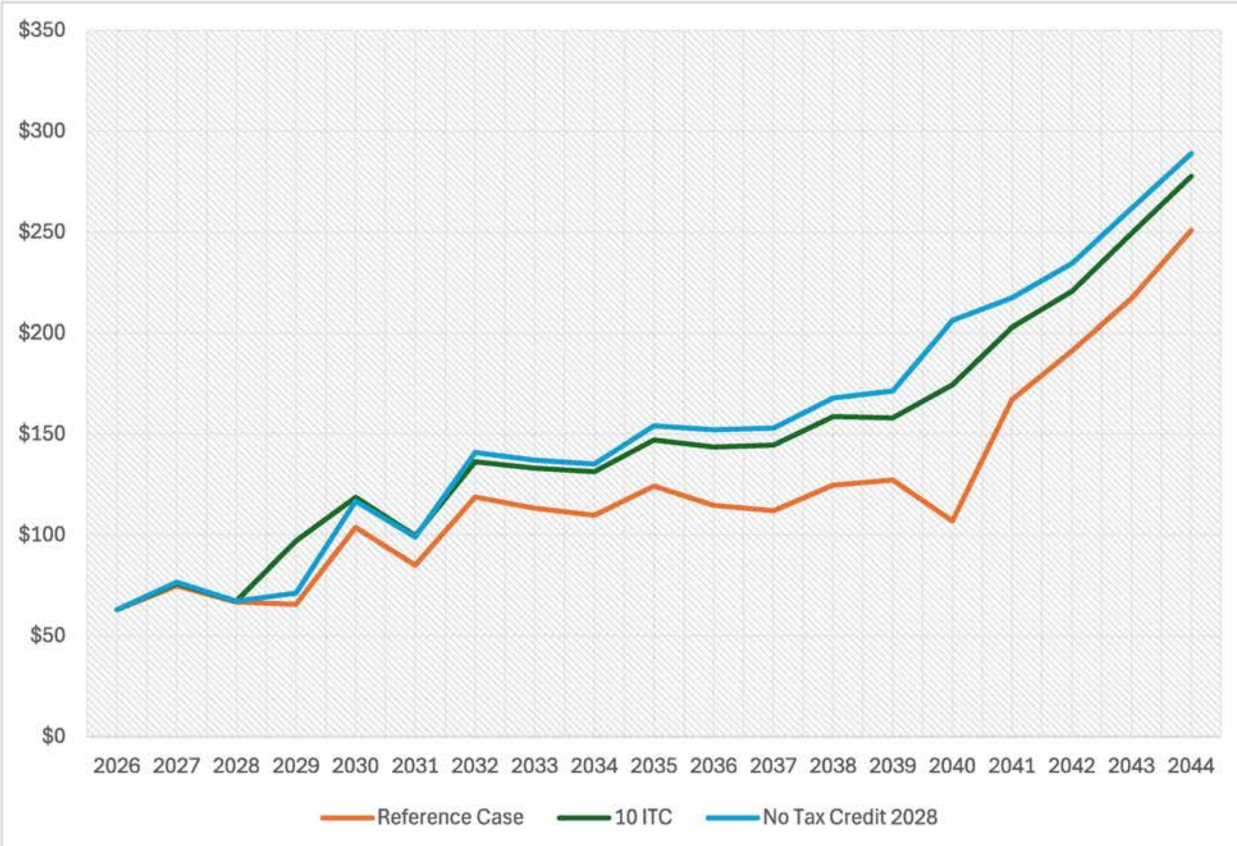


**Figure 90. Annual portfolio generation cost by tax scenario ($/MWh)**



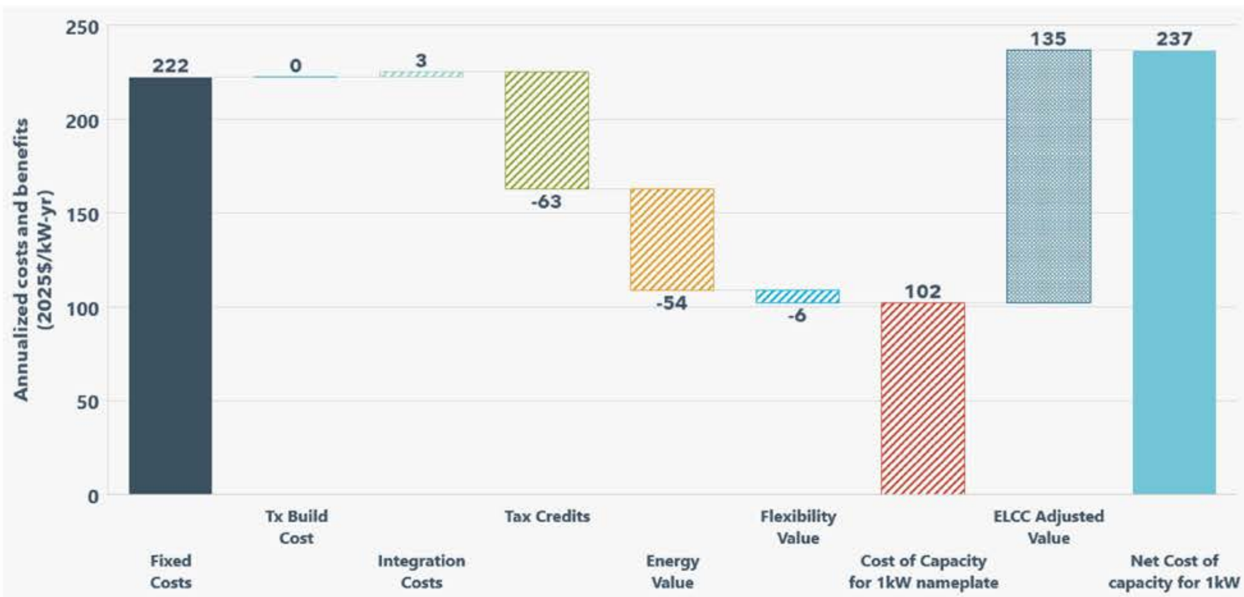

## 6.7 Net cost of capacity resources

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

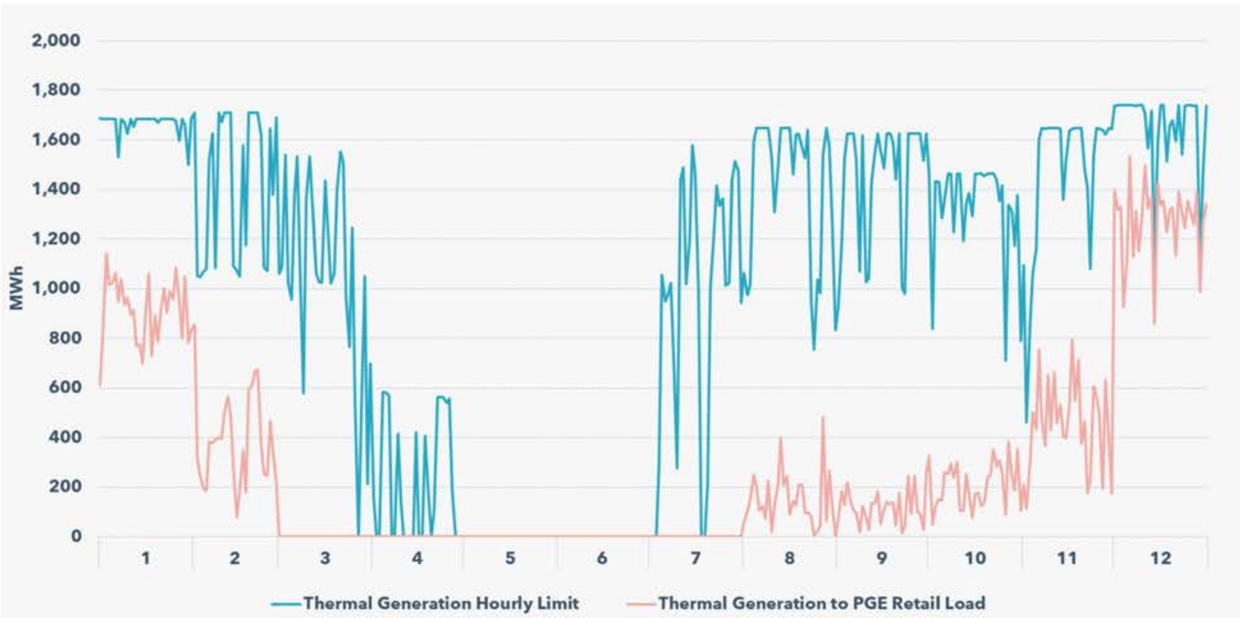
To solve the problem identified in **Section D.1**, PGE has modified the PZM to dispatch PGE resources at minimum cost subject to the constraint that retail load obligations are met with the HB 2021 annual emissions cap in place. This model is called the Modified PZM. The effect of changing the dispatch 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**

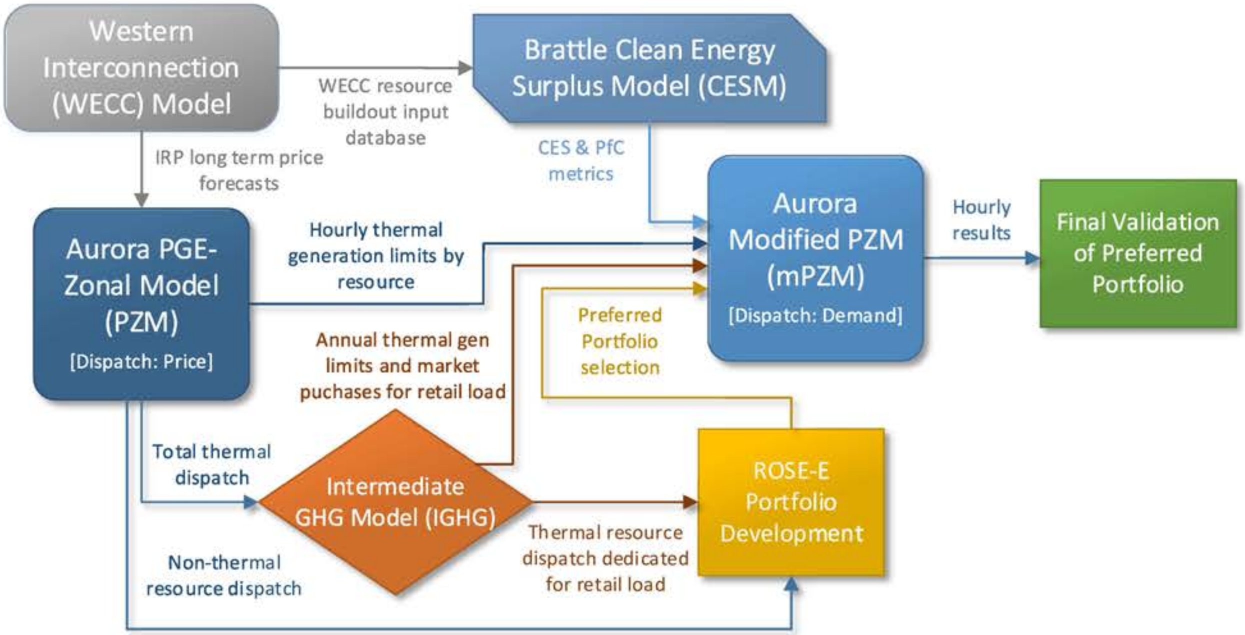



The results of the Modified PZM system dispatch are sent to the excel-based Hourly Energy and Emissions Accounting Workbook (Hourly Workbook). The Hourly Workbook is designed to apply the IGHG-allocated unspecified market purchases using the price-sorting methodology. Any remaining short energy position 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

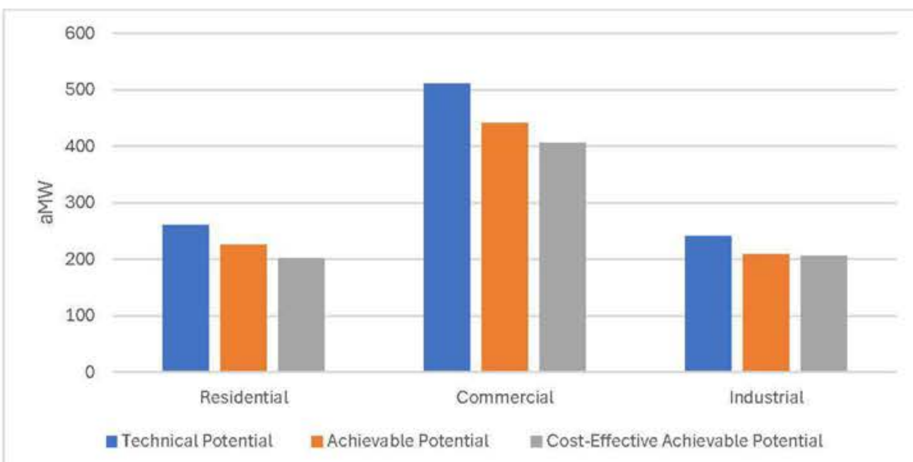
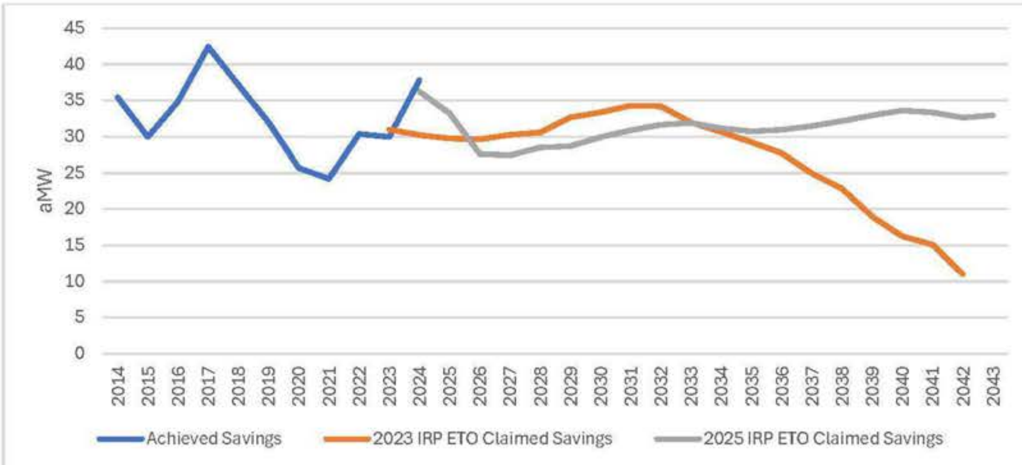



Figure 2 links actual historic savings going back to 2014 to the Energy Trust claimed savings projection for the 2025 IRP. It also compares the 2025 IRP forecast to the 2023 IRP forecast.

[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

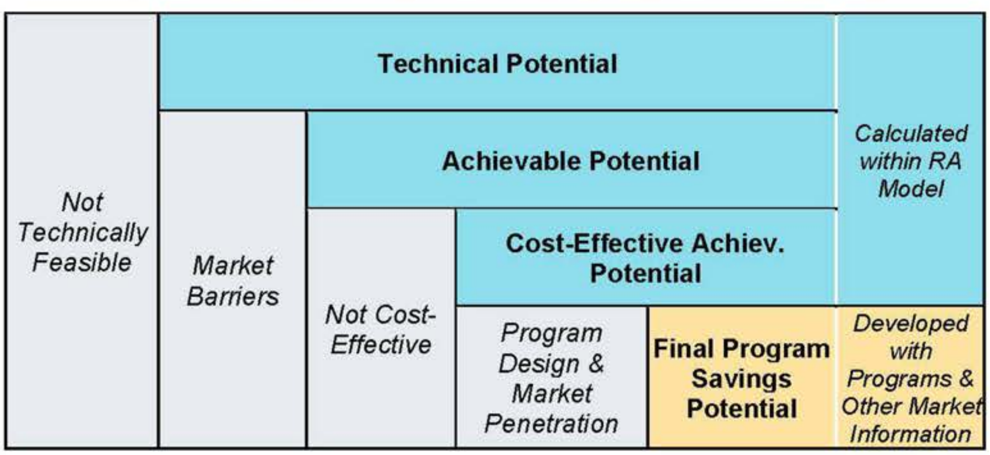



## Energy Trust 20-Year Forecast Methodology

### 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

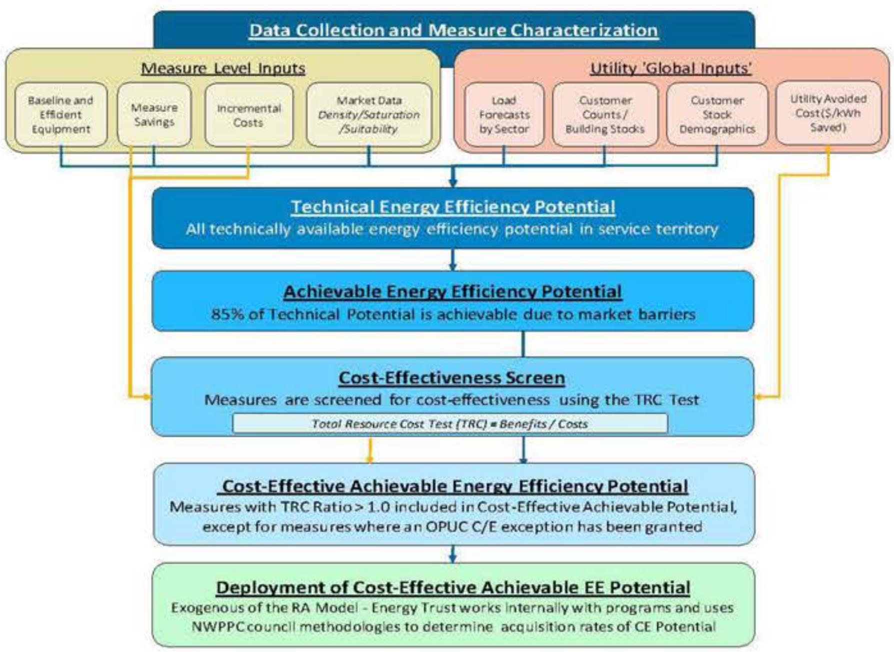


The RA Model utilizes the modeling platform Analytica®[4], an object-flow based modeling platform that is designed to visually show how different objects and parts of the model interrelate and flow throughout the modeling process. The model utilizes multidimensional tables and arrays to compute large, 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,

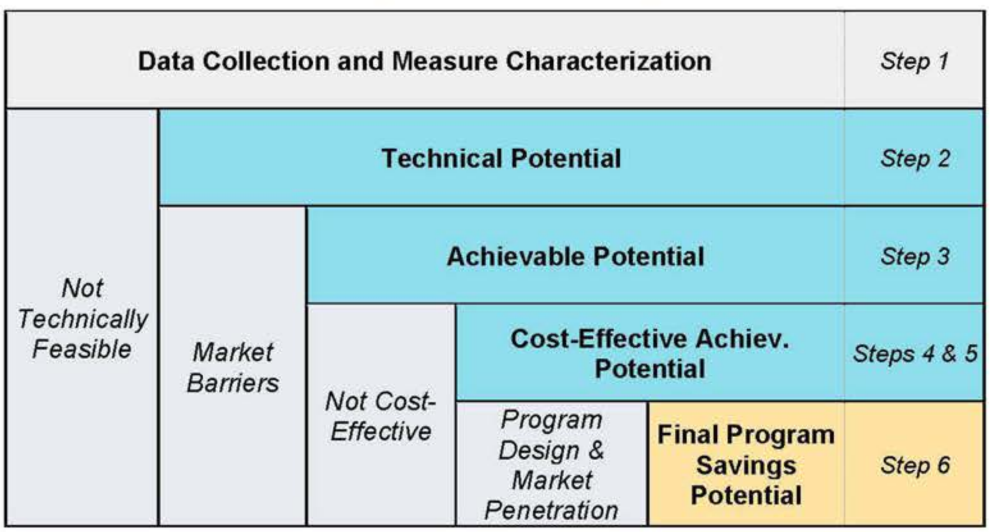
[8] As directed in OPUC docket UM-551 and 2017 ORS 757.054

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.

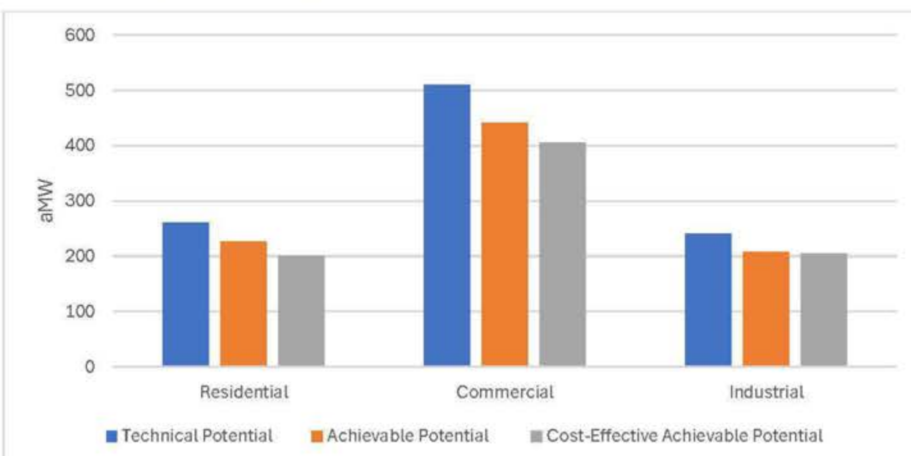
**Table 1 - Summary of Cumulative Modeled Savings Potential - 2024–2043**

| 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**

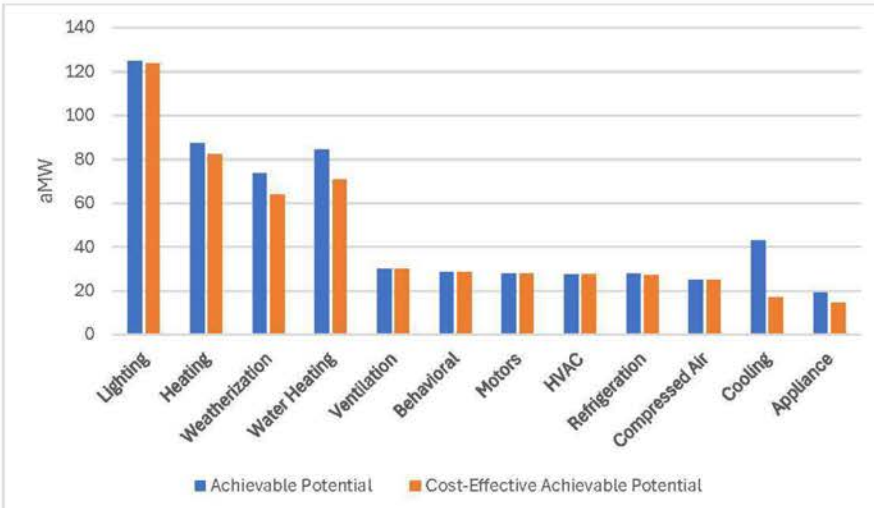



### Cost-Effective Achievable Savings by End-Use

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<br>•Thin Triple Pane Windows<br>• Advanced Insulation<br>• Heat Pump Dryers<br>• Split System CO2 Heat Pump Water Heater<br>• Smart Line Voltage Thermostats | • Zero Net Energy Ready Construction<br>• Hybrid Indirect-Direct Evaporative Cooler<br>• Advanced Refrigeration Controls<br>• Refrigeration Anti-Fogging Film<br>• Advanced Window Technologies | • CO2 Refrigeration<br>• Industrial Heat Pumps<br>• 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

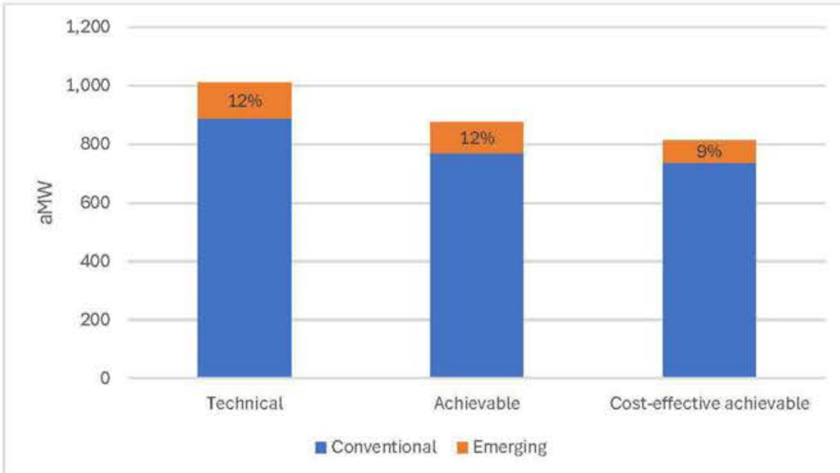
The framework for assigning the risk factor is shown in Table 3. Each ET was assessed within each risk category and a total weighted score was then calculated. Well-established and researched technologies have lower risk factors while nascent, unevaluated technologies (e.g., CO2 heat pump water heaters) 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:**<br>• Requires new/changed business model<br>• Start-up, or small manufacturer<br>• Significant changes to infrastructure<br>• Requires training of contractors. Consumer acceptance barriers exist | | | **Low Risk:**<br>• Trained contractors<br>• Established business models<br>• Already in U.S. Market<br>• 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** |

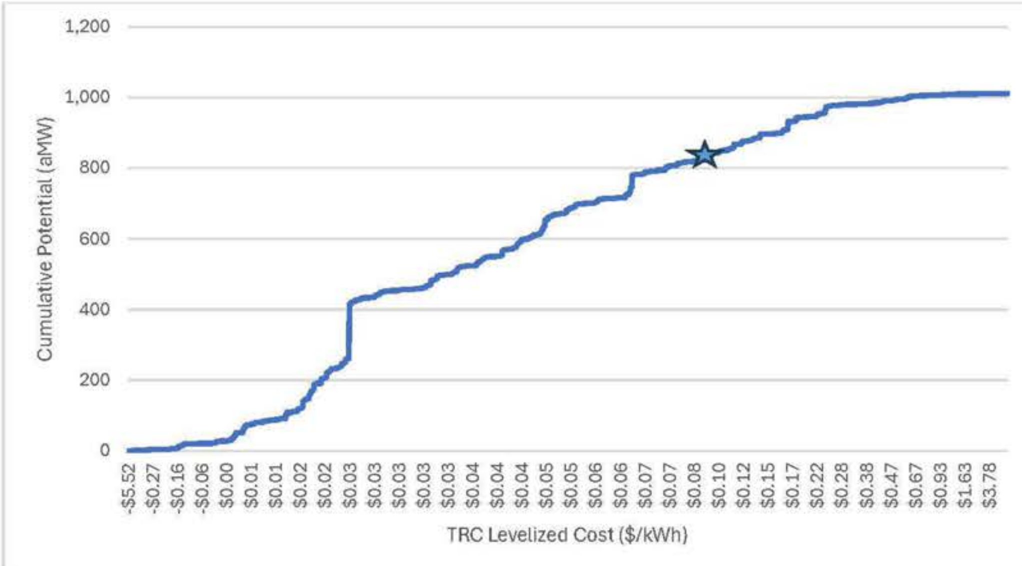
In this IRP, 9% of the cost-effective potential identified by the model is due to the use of the cost-effective override for measures. This is a higher share than in previous IRPs and is attributable to the OPUC cost-effectiveness exception for manufactured homes early replacement (14 aMW of the 69 aMW 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.

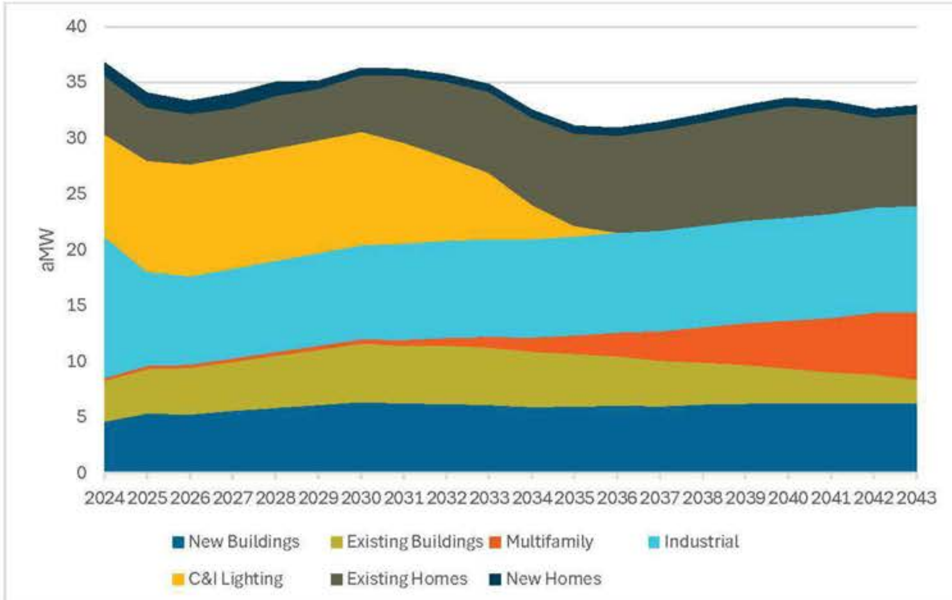
Energy Trust's general modeling principle is to deploy 100% of retrofit cost-effective achievable potential or ramp to 100% of cost-effective achievable potential for replacement and new construction measures consistent with Northwest Power and Conservation Council ramp rate methodology. However, certain 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.

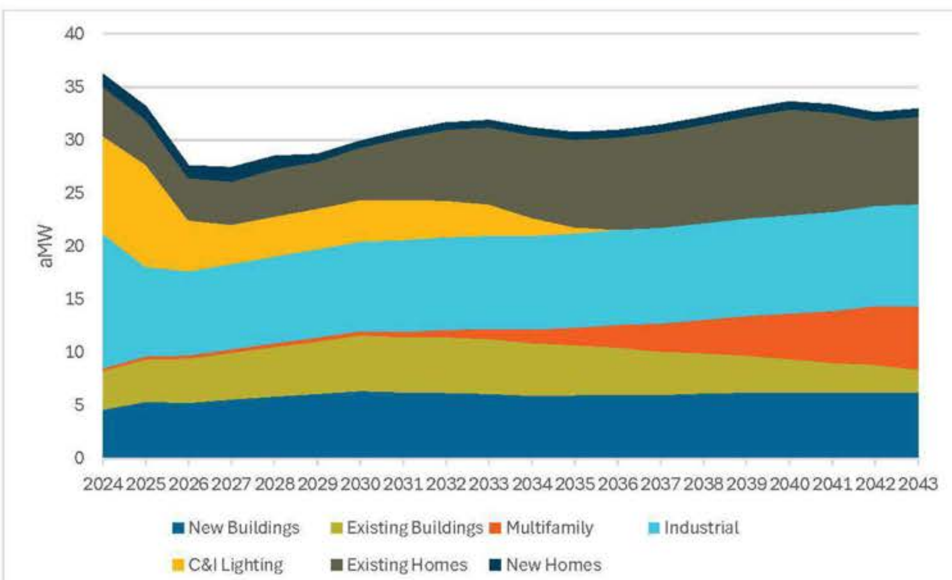
The final savings projection of 675 aMW in Table 5 represents 20-years of efficiency savings. The annual shape of the deployed efficiency forecast is shown in Figure 10 below.

Figure 10 – Annual Deployed Final Savings Potential



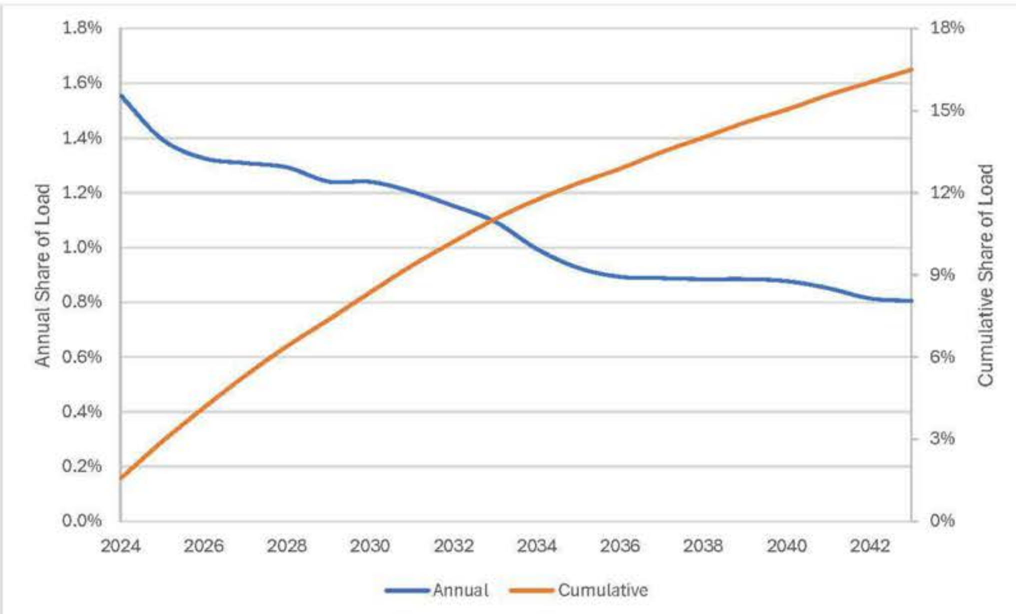

As previously noted, the final savings projection depicted in Figure 10 above includes 47.5 aMW of market transformation lighting savings that energy trust will not claim. Figure 11 below shows the annual efficiency forecast of Energy Trust claimed savings.

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**

*Peak factor = (1 yr/8760) * Load Factor * 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

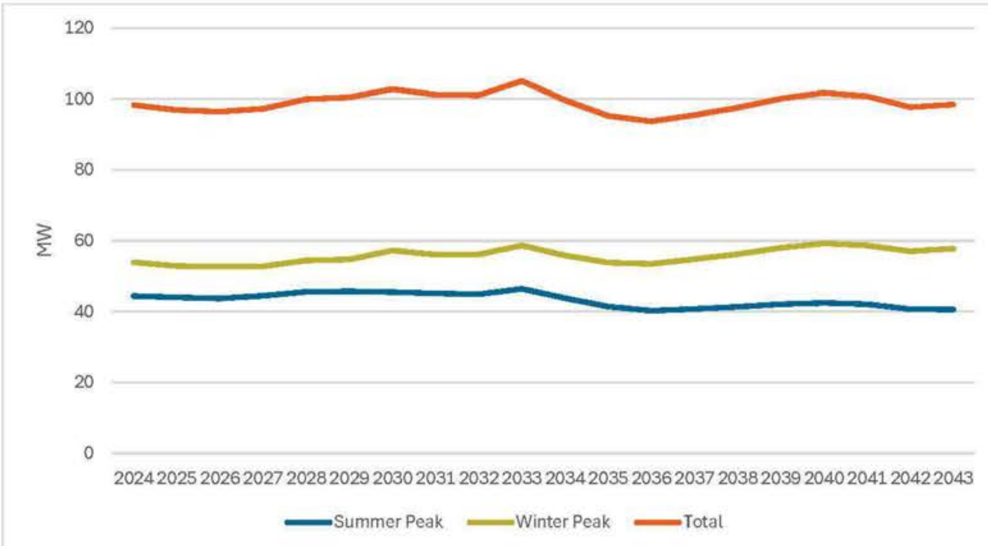



Table 6 - Cumulative Deployed Peak Savings Contribution by Sector

| 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.

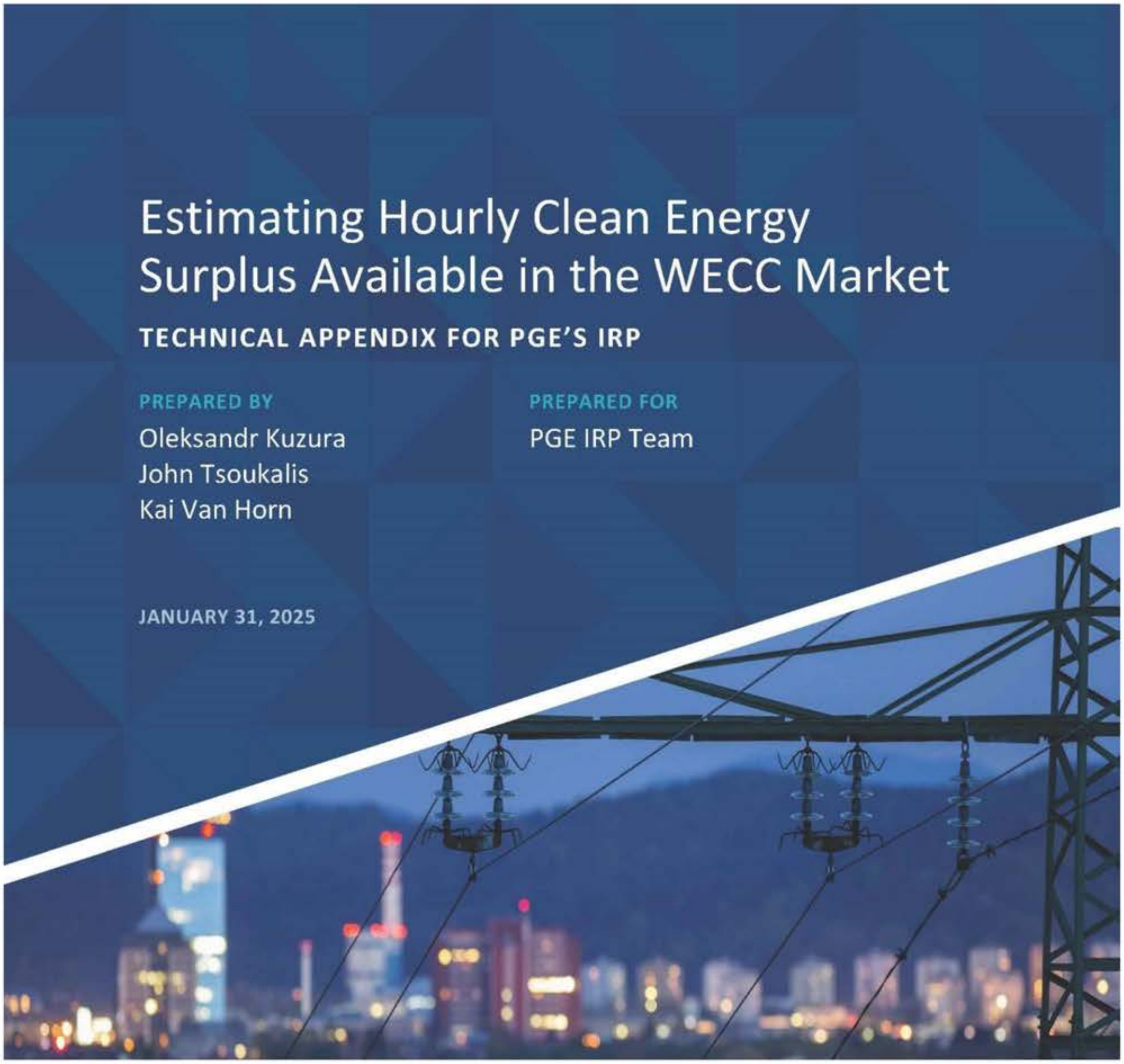
Table 7 – 20-year Non-Cost-Effective Efficiency Potential

| 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



## Estimating Hourly Clean Energy Surplus Available in the WECC Market

**TECHNICAL APPENDIX FOR PGE'S IRP**

PREPARED BY
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PREPARED FOR
PGE IRP Team

JANUARY 31, 2025

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.

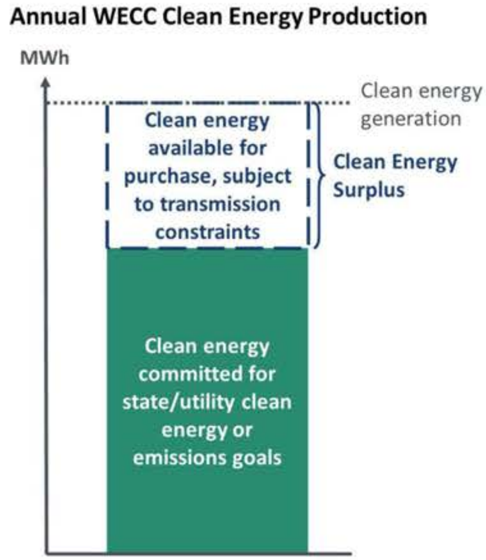
Section III details the CESM's premium calculation approach. Section IV summarizes the CESM's clean energy surplus and premium results for two AURORA simulations. Section V discusses the CESM's strengths and areas for potential future improvements.

# 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

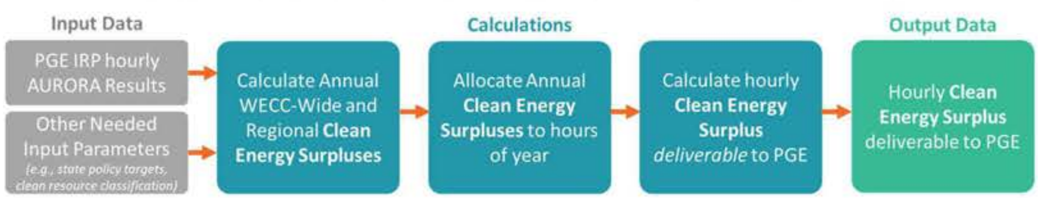



Using the CESM, we calculate hourly clean energy surpluses deliverable to PGE by:

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.

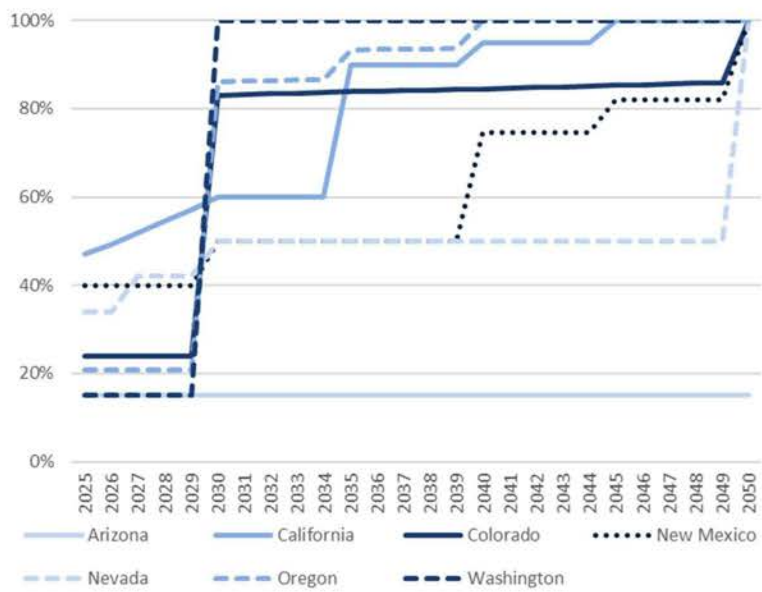
## 2. Calculate State-Level Annual Clean Energy Requirements

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.

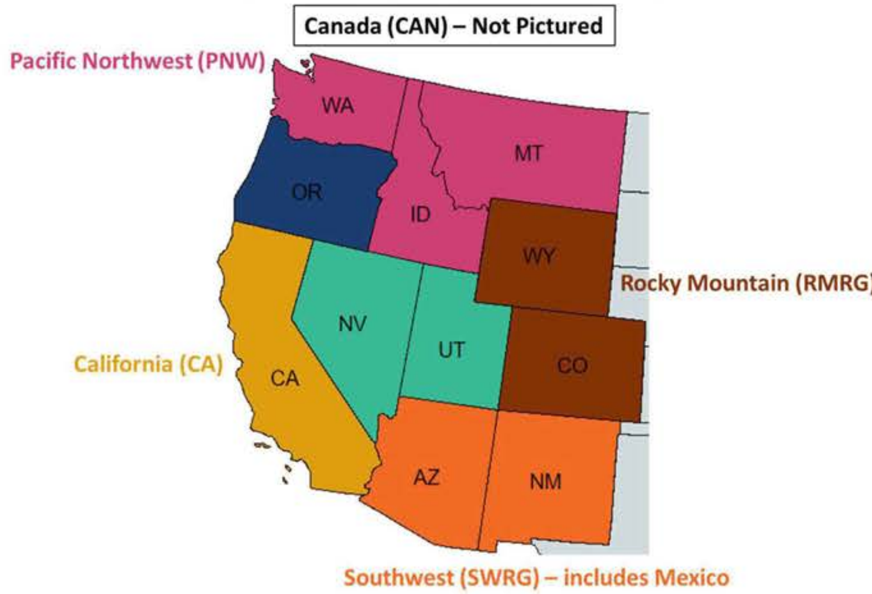
For states with gross annual deficits of clean energy, we calculate the allocation factor as the difference between the state's annual clean energy target and the state's total annual clean energy production. This allocation factor is then used to determine quantity of clean energy procurement the state 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.

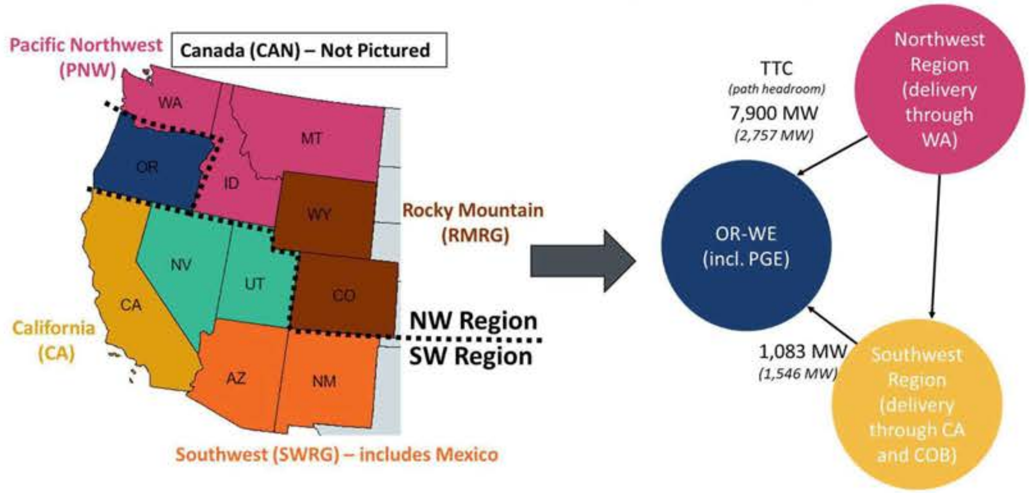
FIGURE 4. REGIONAL AGGREGATION IN THE CESM




## 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.

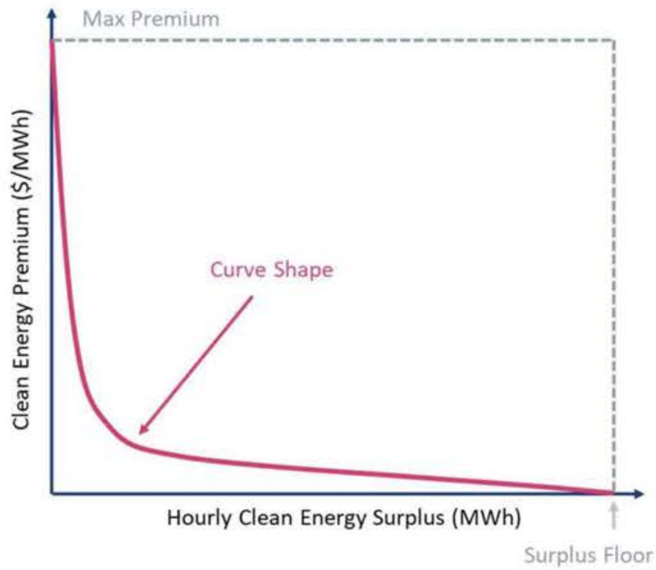
## 1. Create a WECC-Wide CEPC for the Simulation Year

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

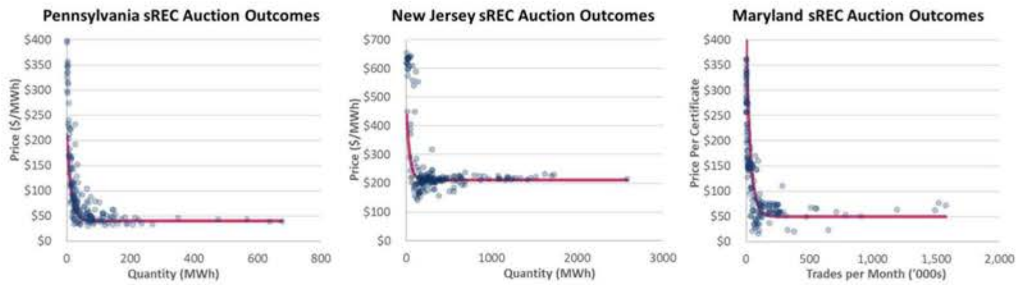



## CEPC Curve Shape Parameter

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

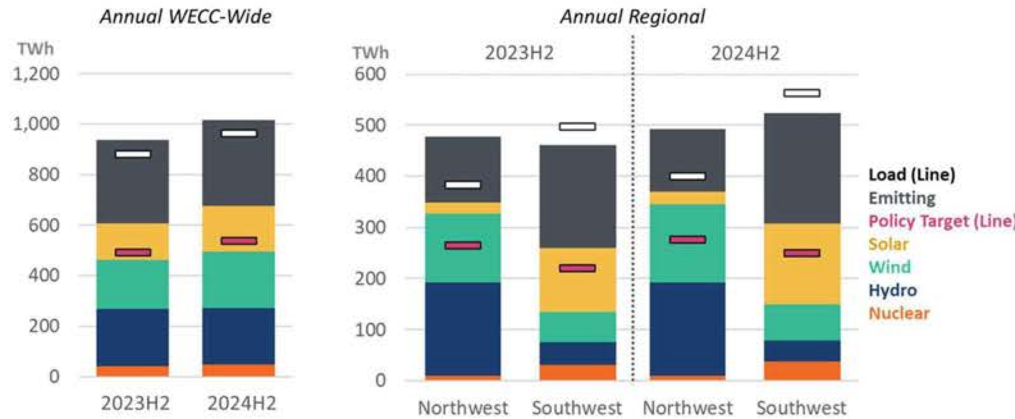
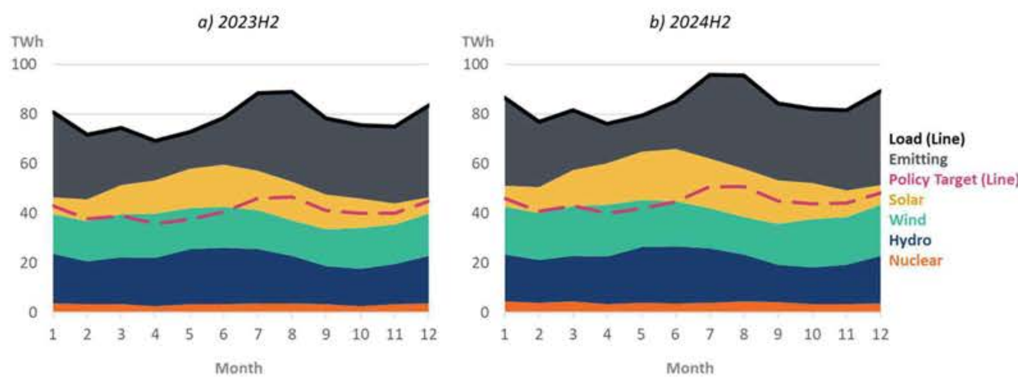
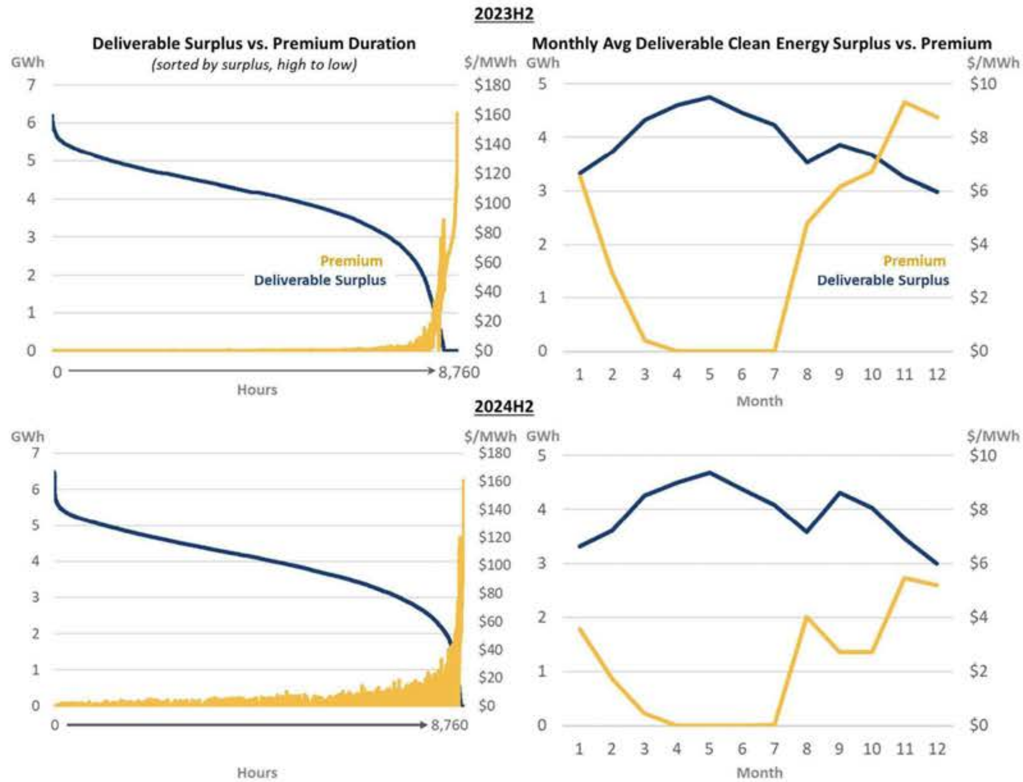



FIGURE 9. MONTHLY GENERATION ASSUMPTIONS IN THE AURORA MODEL



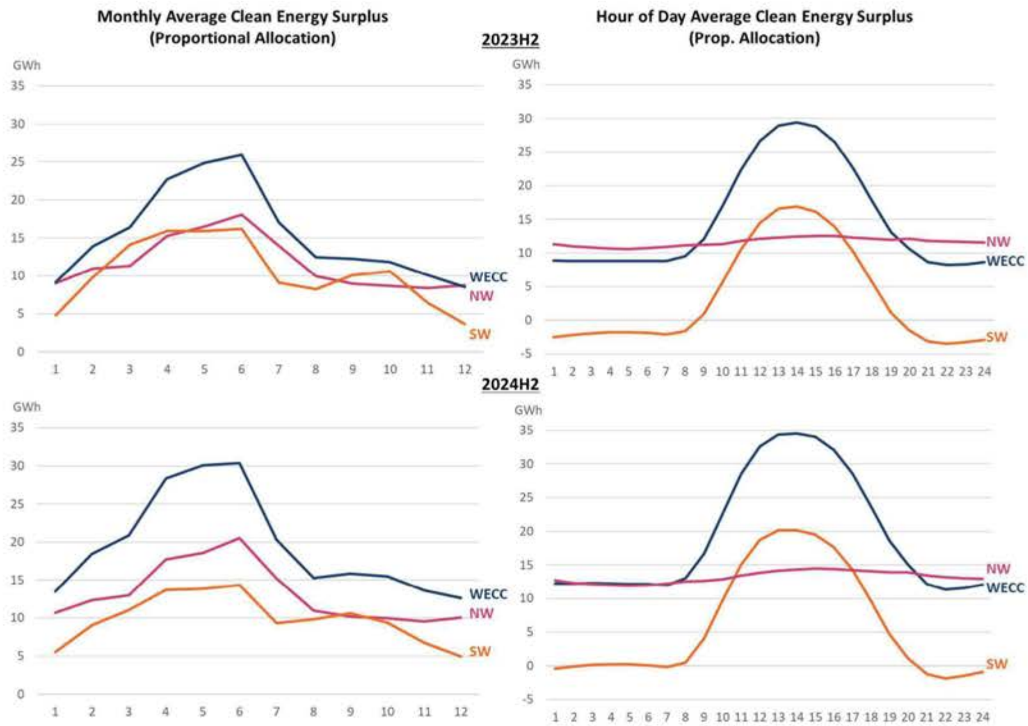

We find that deliverable surpluses are highest in the spring and early summer, roughly in line with the seasonality of clean generation. Premiums follow an inverse pattern and are highest in the winter, when surpluses are low, reflecting the price-quantity relationships defined in the CEPC. Figure 10 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.

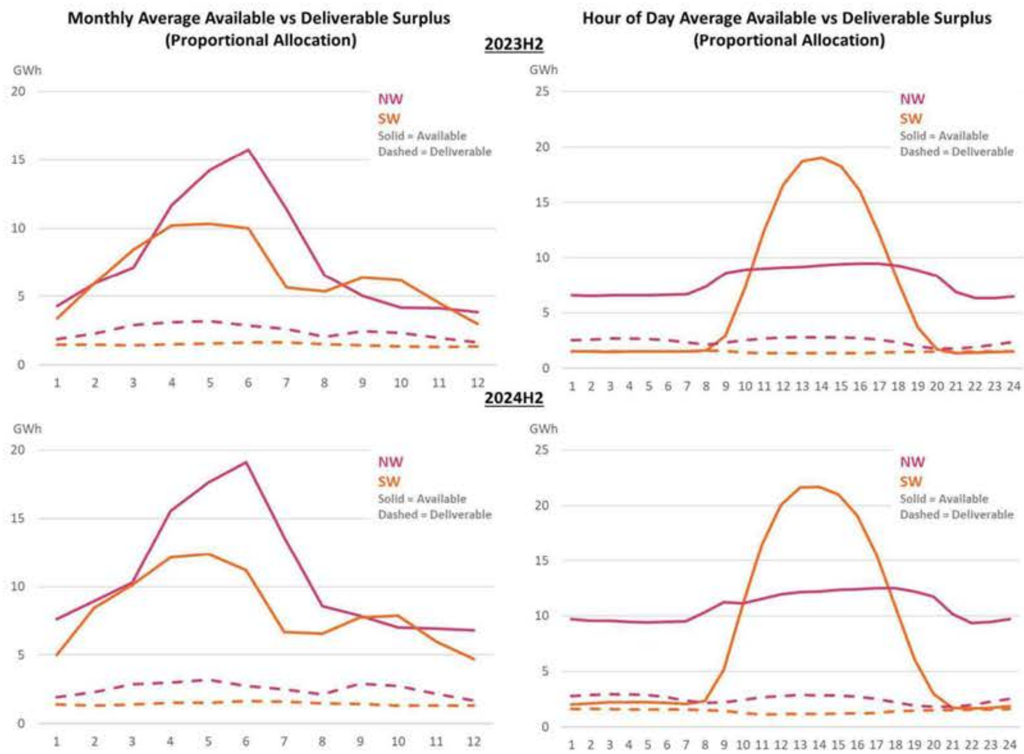
FIGURE 11. WECC-WIDE AND REGIONAL SURPLUSES[5] BY MONTH AND HOUR OF THE DAY




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.

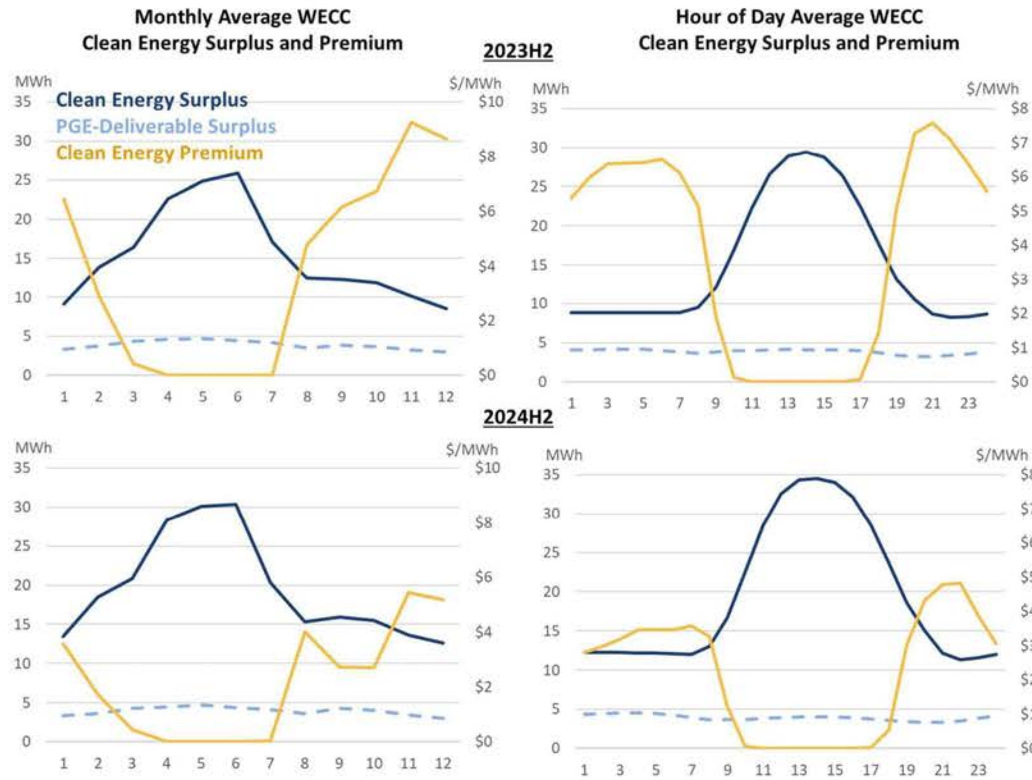
FIGURE 12. REGIONAL SURPLUS DELIVERABILITY RESULTS[6]




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.

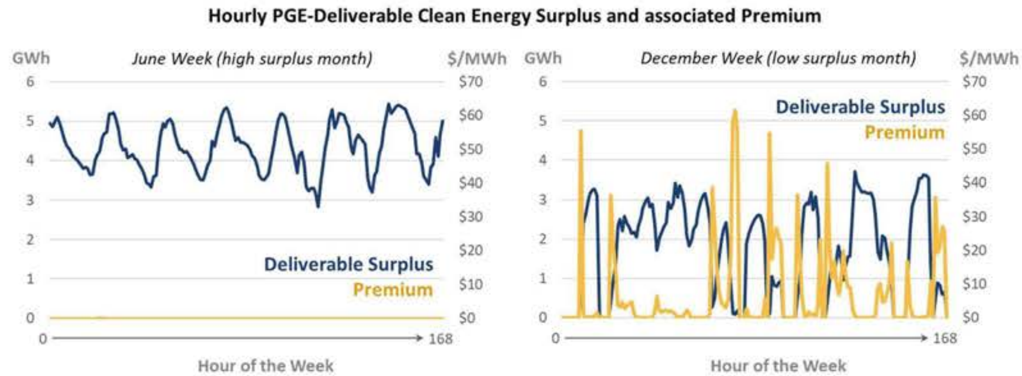
6 Regional surpluses reflected in Figure 12 reflect surpluses deliverable from the respective regions. The solid lines indicate available surpluses after accounting for transfers from RMRG and between the NW and SW regions. The dotted lines indicate the regional surpluses deliverable to PGE.

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




# 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

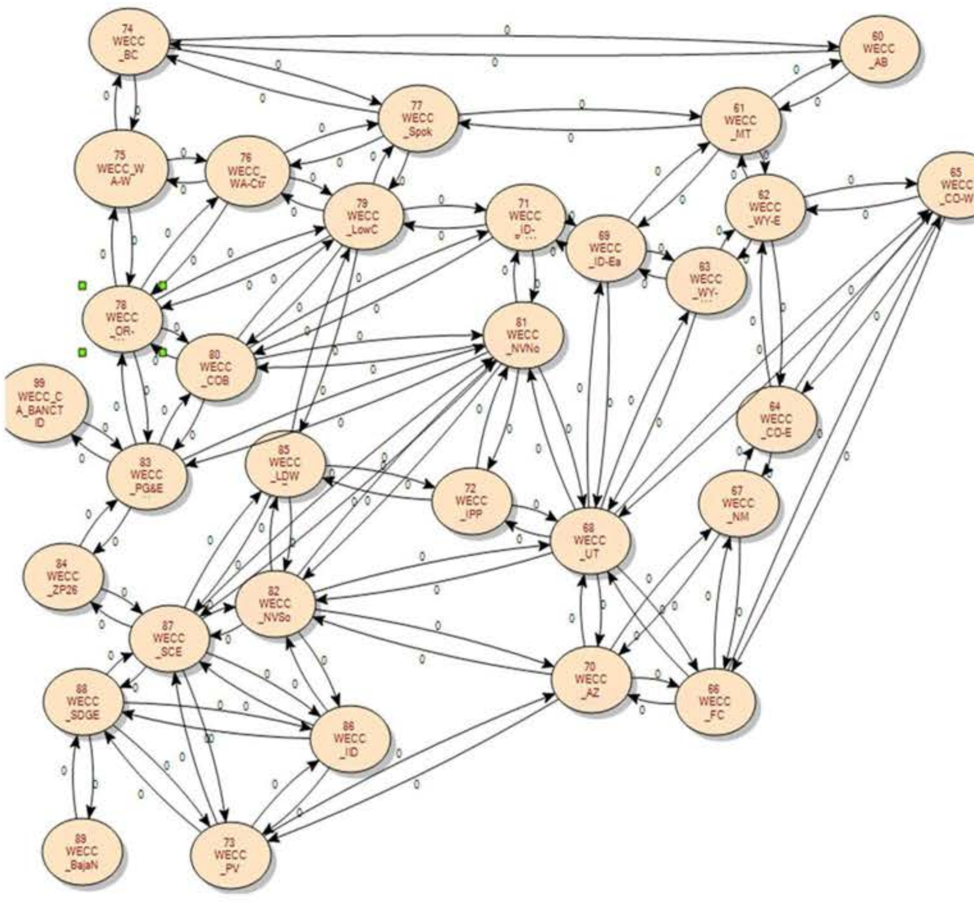



Table 1 contains a mapping of zones modeled in AURORA to WECC states.

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.3.2.2 Voltage 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.3.2.3 Transient 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

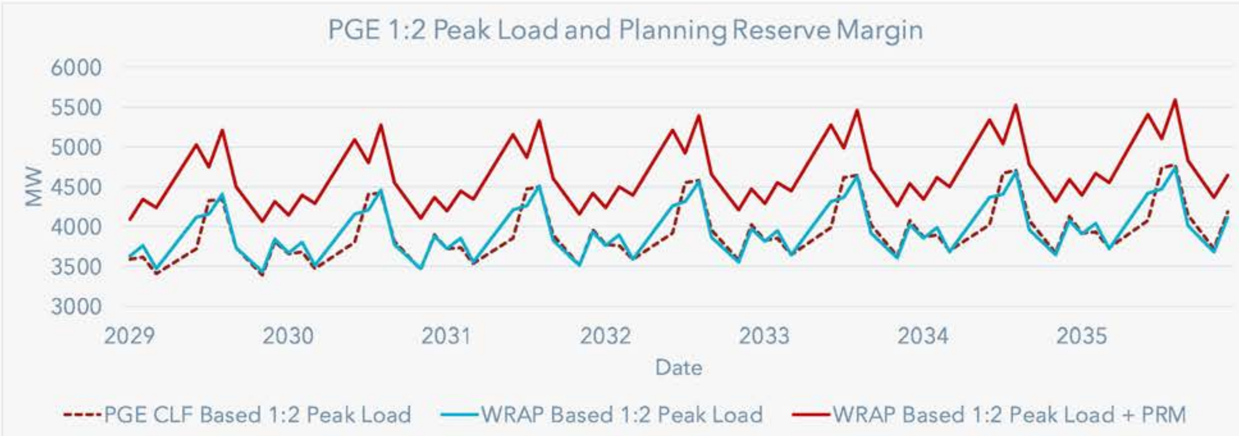
PGE used demand and supply assessment methods from the Western Resource Adequacy Program (WRAP) to analyze the adequacy of PGE's system across the IRP planning horizon. These methods provide the primary metrics needed to derive capacity need and ELCCs for portfolio modeling based on State RA Requirements, 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.

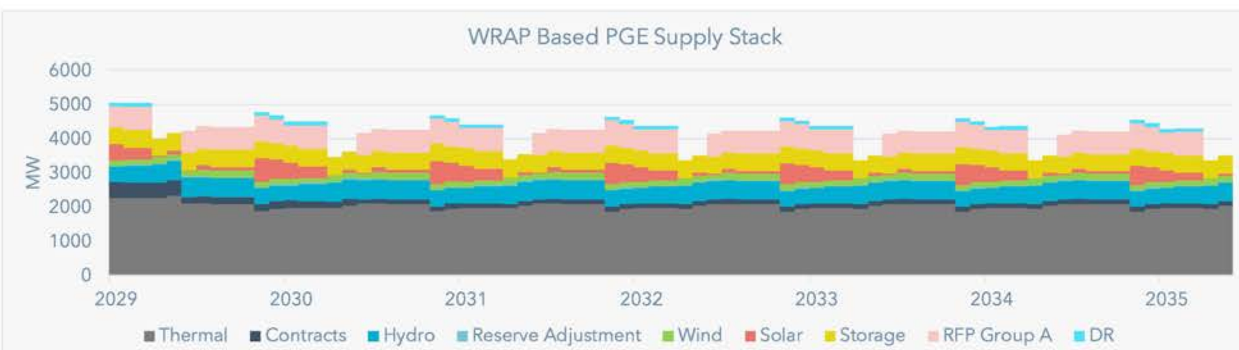
**Figure 94. WRAP Based PGE 1:2 Peak Load and Planning Reserve Margin**




## 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.

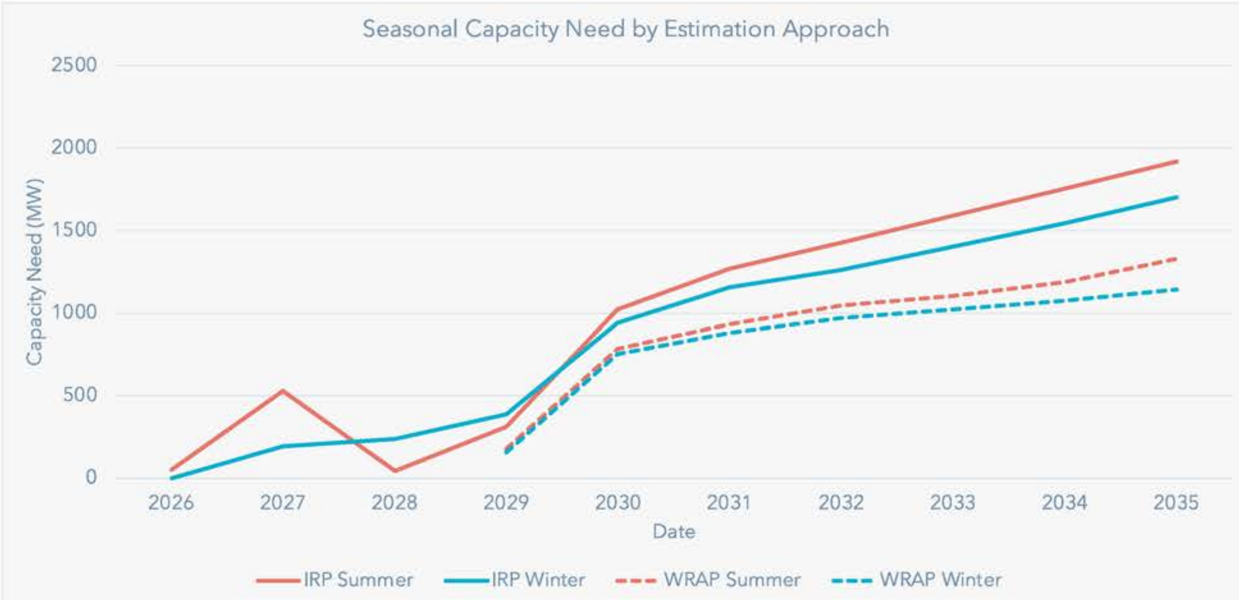
**Figure 95. WRAP Based PGE Supply Stack**




## 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**

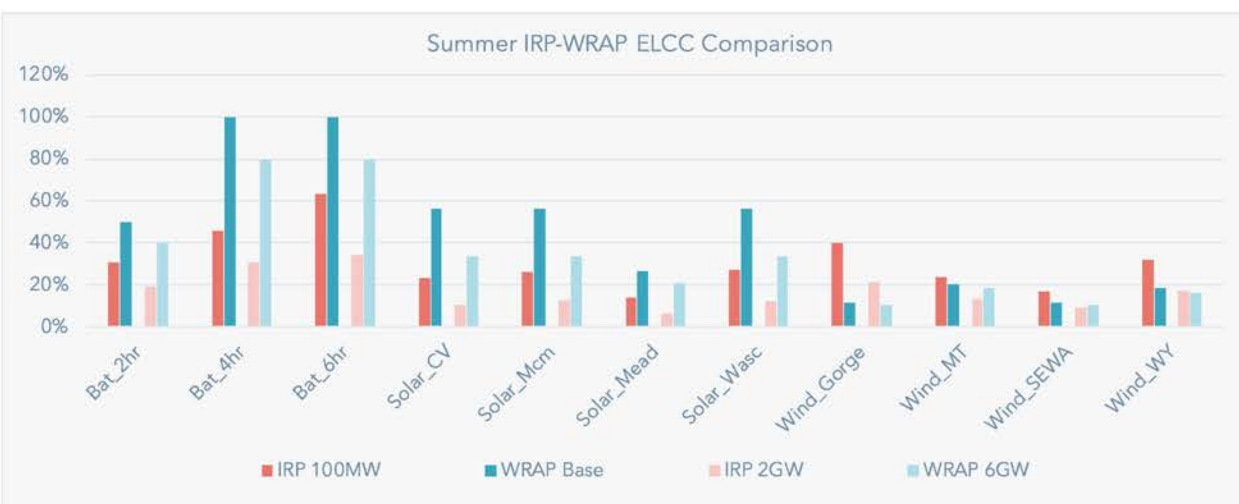
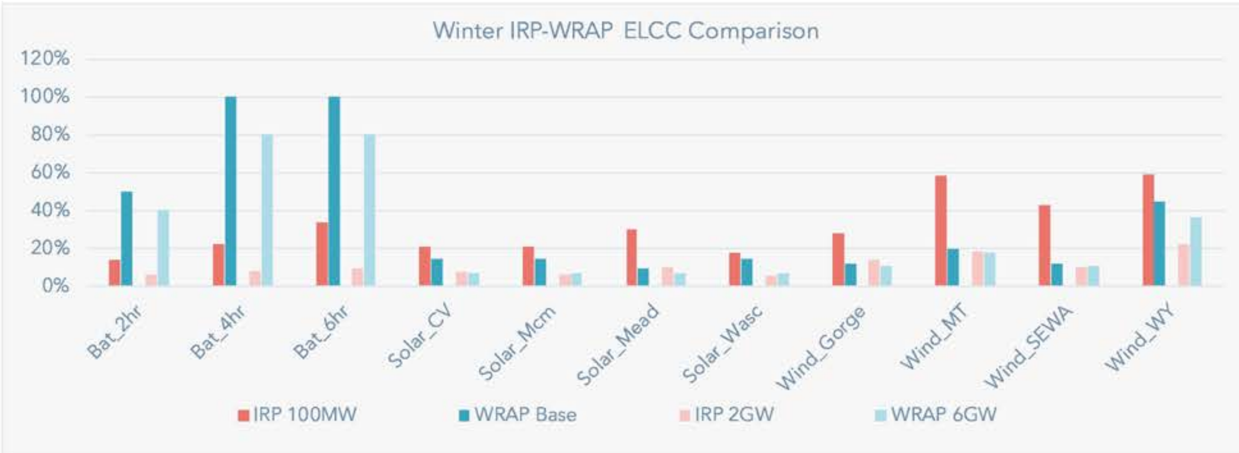


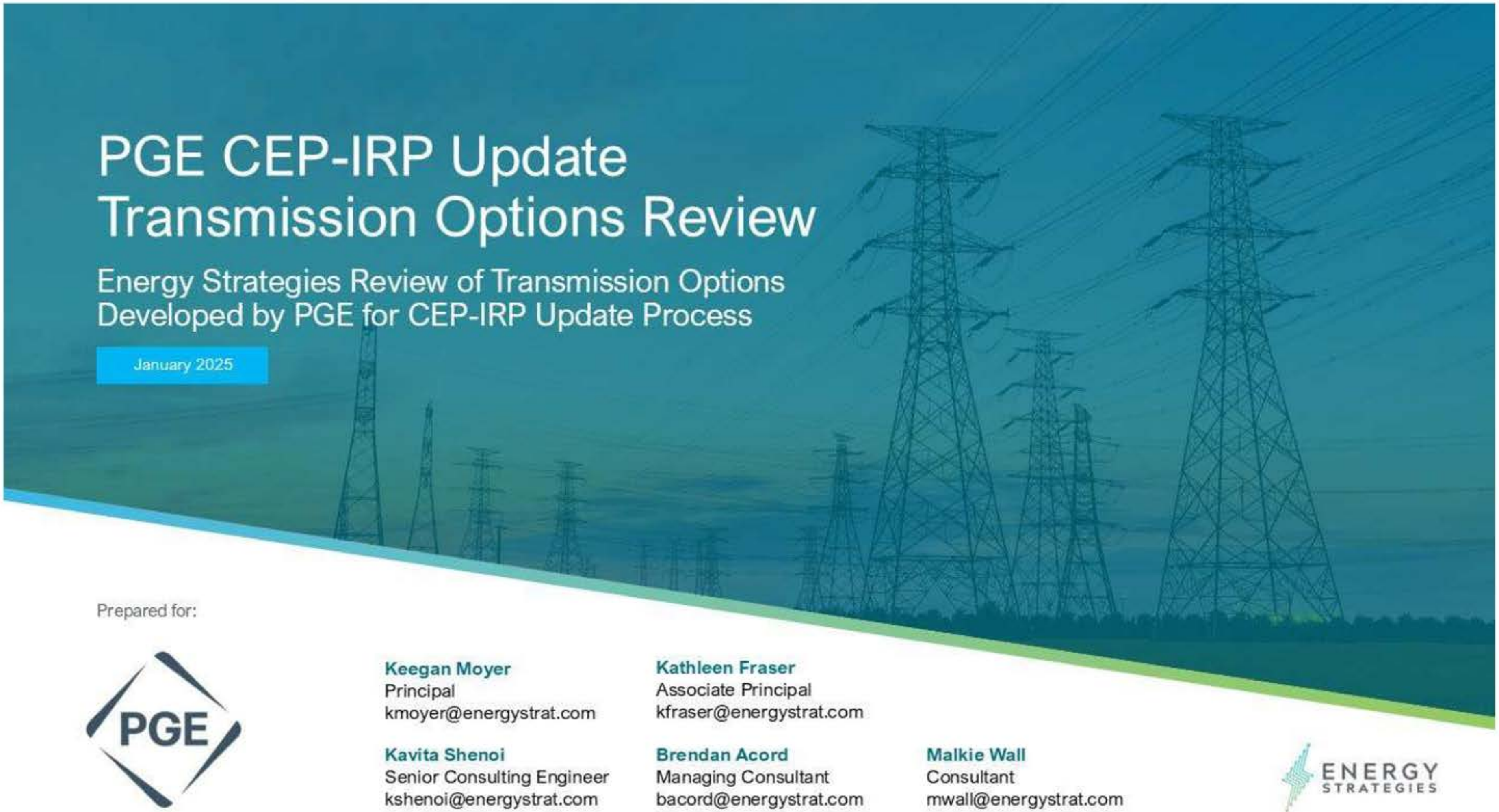
**Figure 98** shows a similar comparison for the winter season. Winter WRAP ELCCs for storage resources continue to be significantly greater than IRP estimates for similar storage resources, while IRP estimates of solar and wind resources are greater.

**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



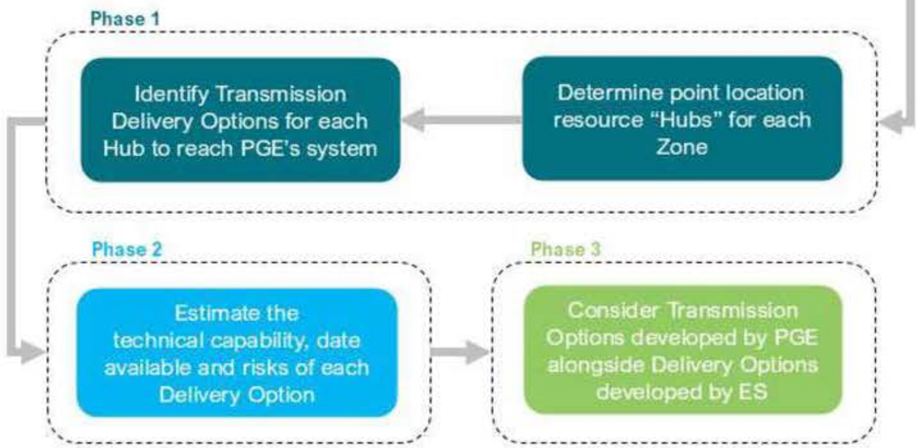
ENERGY STRATEGIES

# 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

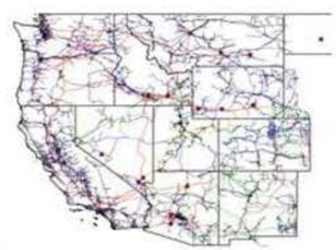
ENERGY STRATEGIES

# 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

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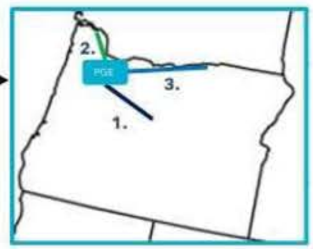
ENERGY STRATEGIES

# 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.

PGE | IRP Regional Transmission Study

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.<br>• 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.<br>• 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.<br>• 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

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PGE | IRP Regional Transmission Study

# "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<br>• Schultz-Raver 500 kV Line Upgrade<br>• Paul 500 kV Substation Upgrade<br>• Olympia 230 kV Substation Upgrade |
| 2 | Big Eddy-Chemawa 230/500 kV Line Upgrade |
| 3 | Portland Area Upgrades<br>• Pearl-Sherwood McLoughlin 230 kV Line Upgrade<br>• Keeler-Horizon 230 kV Line<br>• 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 |

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ENERGY STRATEGIES

# Review of PGE Proposed Transmission Options and Selected Alternatives

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# 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

ENERGY STRATEGIES

# 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).

PGE | IRP Regional Transmission Study

# 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).

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# 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.

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# 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.

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ENERGY STRATEGIES

# 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.

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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).

ENERGY STRATEGIES

# Appendix: Review of PGE Oregon/PNW Specific Transmission Options

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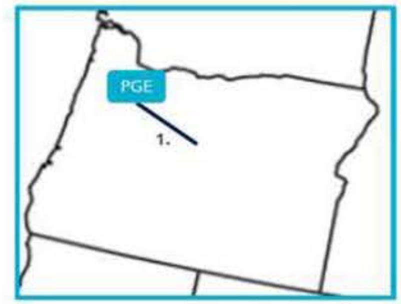
# Bethel – Round Butte 500kV Upgrade

**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:**



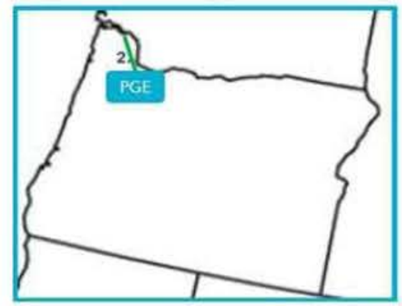

- **Energy Strategies' conclusions:**
  - As noted in the PGE 2023 CEP/IRP this upgrade is a "no regrets" option and facilitates significant access to queued resources.
  - However, depending on the reconductoring configuration chosen, the total transfer capacity is likely to reach only 3000 MW.

# 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.

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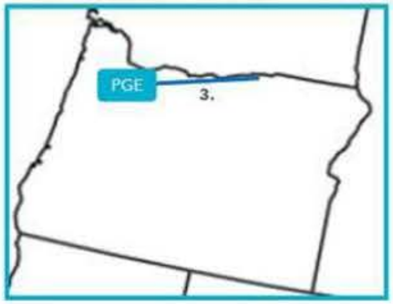
ENERGY STRATEGIES

# 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.

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