2026 Clean Energy Plan and Integrated Resource Plan

Portland General Electric

The 2026 CEP/IRP contains forward-looking statements within the meaning of the federal securities laws, including statements regarding PGE's expectations, plans, objectives and projections; future resource needs; potential generation, storage and transmission additions; procurement activities; emissions reduction pathways; projected customer demand; reliability and affordability objectives; financing requirements; and the timing, outcome, and effects of regulatory proceedings, including the review of the 2026 CEP/IRP by the OPUC.

Forward-looking statements are based on management's current expectations and assumptions and are subject to risks and uncertainties that could cause actual results to differ materially from those expressed or implied by such statements. Factors that could cause actual results to differ materially include, among others: the outcome of regulatory review and approval processes; changes in applicable laws; regulations and governmental policies; the availability, cost, and timing of generation, storage, transmission and other energy resources; supply chain constraints; permitting, siting, development and construction delays; changes in load growth forecasts, customer demand, or energy market conditions; the availability and cost of capital; PGE's ability to obtain financing on favorable terms, or at all, to support resource acquisitions, transmission investments, and other initiatives contemplated by the CEP/IRP; inflation, interest rates and credit market conditions; technological developments; environmental and operational risks; and other risks and uncertainties discussed in PGE's filings with the U.S. Securities and Exchange Commission.

PGE undertakes no obligation to update any forward-looking statement contained in this filing, whether as a result of new information, future events or otherwise, except as required by law.

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Portland General Electric Company

Integrated Resource Planning

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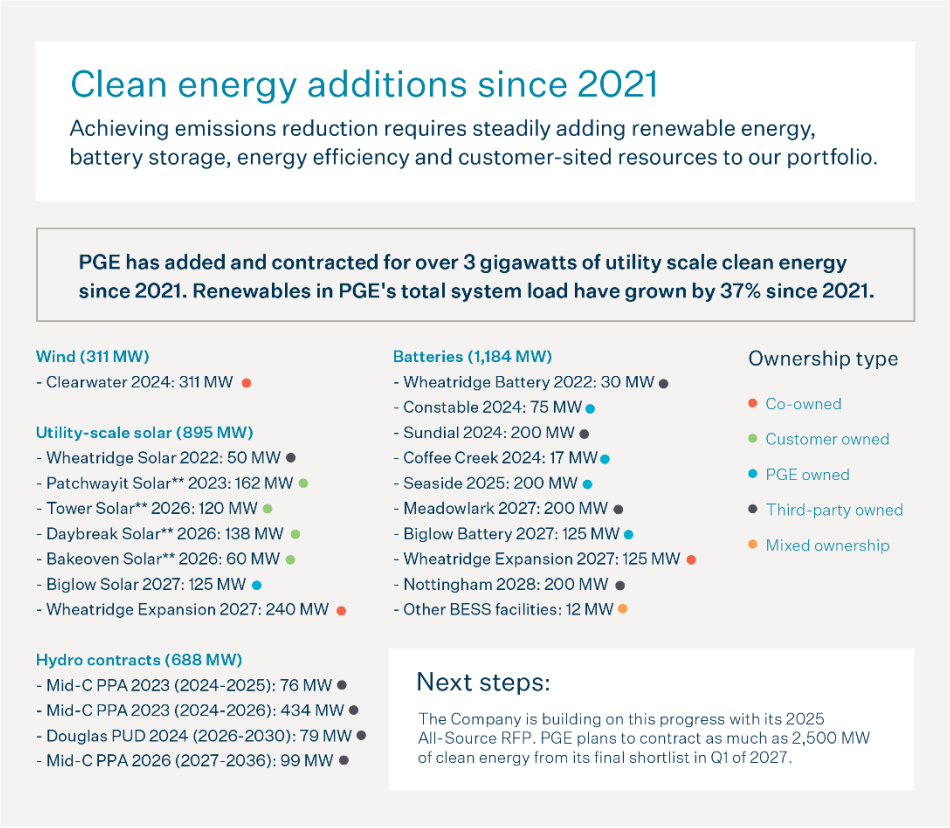
Executive Summary—Clean Energy Plan and Integrated Resource Plan

Cleaner Energy and Safe, Affordable, Reliable Power

Portland General Electric (PGE or the Company) has made remarkable progress advancing a cleaner energy system and reducing greenhouse gas emissions while continuing to serve customers with safe, affordable, reliable power. Since the adoption of House Bill 2021 (HB 2021), PGE has added and contracted for over 3 GW of clean energy and grown renewables in total system load by 37%.

PGE's commitment to its customers has remained unchanged. The Company has continued to meet growing customer demand with increasingly clean power, reducing the emissions intensity associated with retail power by over 10% from 2021 to 2025.[1]

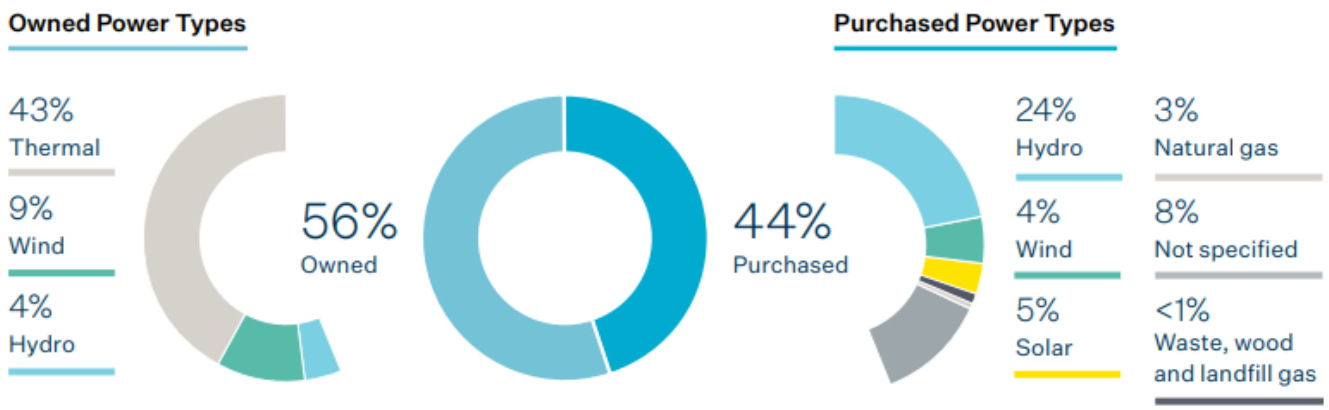
Figure 1. Clean Capacity on PGE's System Since HB 2021 Adoption



1 Based on the utility/proxy peers reported in the National Public Utilities Council Fall 2025 Annual Decarbonization Report.

Since HB 2021 was adopted, PGE has added and contracted for over 3 gigawatts of utility-scale clean energy, associated with investments of approximately $4.5 billion. As PGE has made progress on clean energy, the Company has worked to mitigate the cost impacts to customers by managing its own costs and maximizing savings for customers. PGE has aggressively reduced project costs by securing approximately $1.4 billion of federal clean energy tax credits from our own clean energy portfolio, and estimates as much as another $1.7 billion from long-term, third-party energy contracts. These resource additions have resulted in 56% of the energy PGE served customers with in 2025 from owned resources, with the remaining 44% sourced from power purchases. This owned and purchased resource mix allows PGE to strategically procure clean energy; nearly half of the power served to PGE customers in 2025 was from non-emitting sources.

Figure 2. PGE Owned vs. Purchased Power in 2025



PGE's focus on saving costs also shows up in how PGE manages use of the grid by getting more out of the system customers have already paid for, including: flexible load planning, Grid Enhancing Technologies (GETs), dynamic line ratings, increasing participation in regional energy markets and customer flexibility programs that defer or avoid more expensive infrastructure.

PGE is also working to optimize renewables, batteries, and customer resources to take full advantage of available generation supply. For example, charging batteries with clean energy when demand on the grid is low and delivering it across existing transmission lines when demand on the grid is high.

PGE has maintained a long record of reliable service while the system becomes cleaner, and customer demand grows, decreasing response times to outages over the past five years. Resource planning starts with the core obligation to keep the lights on—ensuring enough capacity, flexibility, reserves, transmission access, and customer-side resources are available to serve customers through peak demand, changing weather, and stressed regional market conditions. PGE's Virtual Power Plant, (VPP) transmission upgrades, existing dispatchable resources, and regional market participation all support that reliability foundation.

PGE's reliability focus is increasingly tested by extreme weather, wildfire risk, and load growth—but PGE's response has been consistent: strengthen the system, use existing assets smarter, and recover faster when disruptions occur. From wildfire mitigation and distribution hardening to

advanced grid technologies and flexible customer resources, PGE is building a cleaner system that remains dependable in the moments customers need it most.

Adding Clean Energy in an Evolving Planning Environment

The operating and planning environments have changed significantly since the passage of HB 2021 and the publication of PGE's inaugural 2023 Clean Energy Plan (CEP). The electric utility landscape has shifted at an unprecedented pace, driven by rising demand, rapidly changing federal policy, increasing wildfire risk and changing market conditions, resulting in significant impacts to clean resource costs and technological advancements.

Even as the region adds significant amounts of clean energy, given increased procurement competition and resource development challenges, the availability of new, clean resources for PGE is becoming increasingly constrained. Many of the most viable wind, solar, and storage projects have already been contracted for by non-regulated energy buyers who are able to move quickly. Remaining projects often face challenges associated with permitting, interconnection, and transmission access. While Executive Orders issued by Oregon's Governor aim to accelerate state permitting, there are delays in federal permitting processes, including Federal Aviation Administration (FAA) reviews for wind projects, as well as continuing uncertainty in local permitting processes. These have further reduced the number of projects capable of meeting near-term utility timelines.

At the same time, growing demand has intensified competition for the pool of clean energy resources. These factors have created a supply-constrained market in which the pace of renewable development is increasingly determined not only by customer demand and policy objectives, but by the practical availability of projects that can be delivered reliably, affordably, and on schedule. As a result, access to clean energy resources has become one of the most important considerations shaping PGE's

Clean Energy Plan (CEP)

PGE develops its CEP alongside its Integrated Resource Plan (IRP), which evaluates a least-cost, least-risk strategy for serving customers' electricity needs over the next 20 years. The CEP builds upon the IRP analysis to describe how PGE's resource strategy advances Oregon's decarbonization requirements outlined in Oregon's landmark climate policy, House Bill 2021.

Integrated Resource Plan (IRP)

The primary goal of this plan is to develop a long-term resource strategy and near-term action plan that allow the utility to meet customer needs while best balancing expected costs and associated risk for the utility and its customers.

- Oregon was one of the first states to require IRPs, which provide a framework for evaluating plausible futures for the utility's electric system and receiving input from stakeholders.
- The objective of an IRP is to demonstrate which resource portfolio—including supply- and demand-side options—is most likely to be optimal in the face of risks and uncertainties.
- IRPs provide information on electricity system costs, risks, reliability, and trends, and answer important questions that affect electricity consumers.

progress towards the emissions reduction goals shared by both PGE's customers and the State of Oregon.

To address our customers' resource needs, PGE is focused on supporting resource investments that provide direct benefits to customers and keep costs as low as possible. PGE's reliability and decarbonization needs identified in this plan will require efficient access to capital markets. No matter the resource owner or commercial structure, the actions identified in this plan will require tremendous investments from capital providers. PGE competes for access to loans and investments, and to secure financing at the lowest possible cost, investors must view PGE as a financially sound and attractive investment. The same consideration applies to resources owned by third parties and operated under long-term contracts: investors are generally unwilling to fund projects without long-term purchase agreements from a financially strong utility such as PGE.

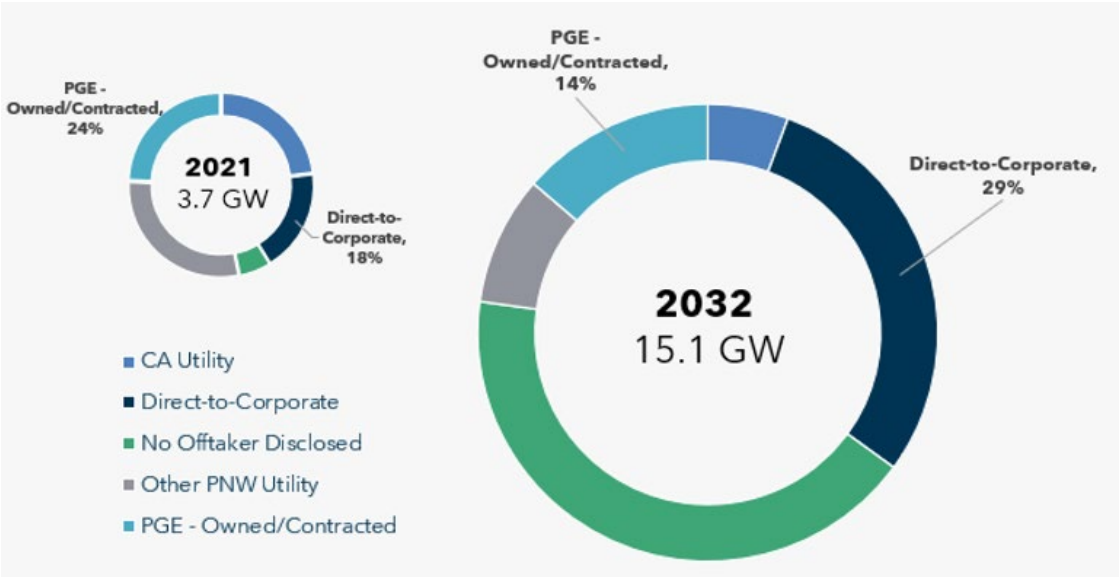
These factors are why PGE continues to advocate for solutions around utility exposure to wildfire risk and a holding company that aligns with common utility structures. PGE performs robust wildfire mitigation activities every year, but wildfire risk continues to be reflected in higher capital costs. Capital costs also increase when financial investment capacity and optionality is limited, which ultimately increase the costs of clean energy projects, making it harder for PGE to achieve the volumes of procurement needed to support decarbonization while balancing affordability.

PGE's analysis demonstrates that clean energy resources remain an effective long-term strategy for serving growing customer needs. Analysis also demonstrates that, when federal tax credits are available, clean energy resources are the most affordable resource. Wind, solar, battery storage, energy efficiency, and customer-sited resources provide reliable contributions to the system when properly integrated and supported by transmission and market access. These resources can be developed using commercially available technologies and can continue to reduce emissions while meeting capacity and energy needs. Near-term clean energy additions can largely be accommodated through existing infrastructure and ongoing grid optimization efforts, while future transmission expansion unlocks access to higher-quality renewable resources and broader regional markets. Together, these findings reinforce that PGE should prioritize investment in clean energy to meet our customers' needs.

PGE remains committed to reducing GHG emissions associated with energy served to retail customers. At the same time, analysis in the 2026 CEP/IRP highlights the importance of carefully managing the pace at which renewable resources are added to PGE's system to maintain reliability and affordability for customers. The unprecedented quantity of resources that are needed to reduce emissions by 80% by 2030 while maintaining system reliability poses clear execution challenges.

The headwinds facing this work are significant. Clean energy supply costs are rising, federal tax credits are scheduled to expire, delays in permitting and siting projects, and competition for limited projects all negatively affect resource prices, availability, and timelines.

Figure 3. Oregon Sited Utility-scale Renewable Resources: Total Online by 2021 and by 2032 - Categorized by Announced Offtaker



Reflecting this reality, the 2026 CEP/IRP differs from previous planning documents in a key respect. It introduces two (2) complementary planning portfolios. The first being the HB 2021 Preferred Portfolio, which identifies the volume of resource additions needed to achieve the HB 2021 emissions targets, as required by rules. This portfolio includes 6,747 MW of resources needed by 2030 to achieve the 80% emissions reduction target, and over 9,000 MW needed in 2032 to stay on track towards the course to 2035 and 2040 targets.

However, the 2026 CEP/IRP highlights a critical reality: the pace of the clean energy transition must be balanced with affordability, reliability, and the industry's ability to deliver projects on schedule. As a result, actual resource additions likely need to be tempered to a volume that is executable.

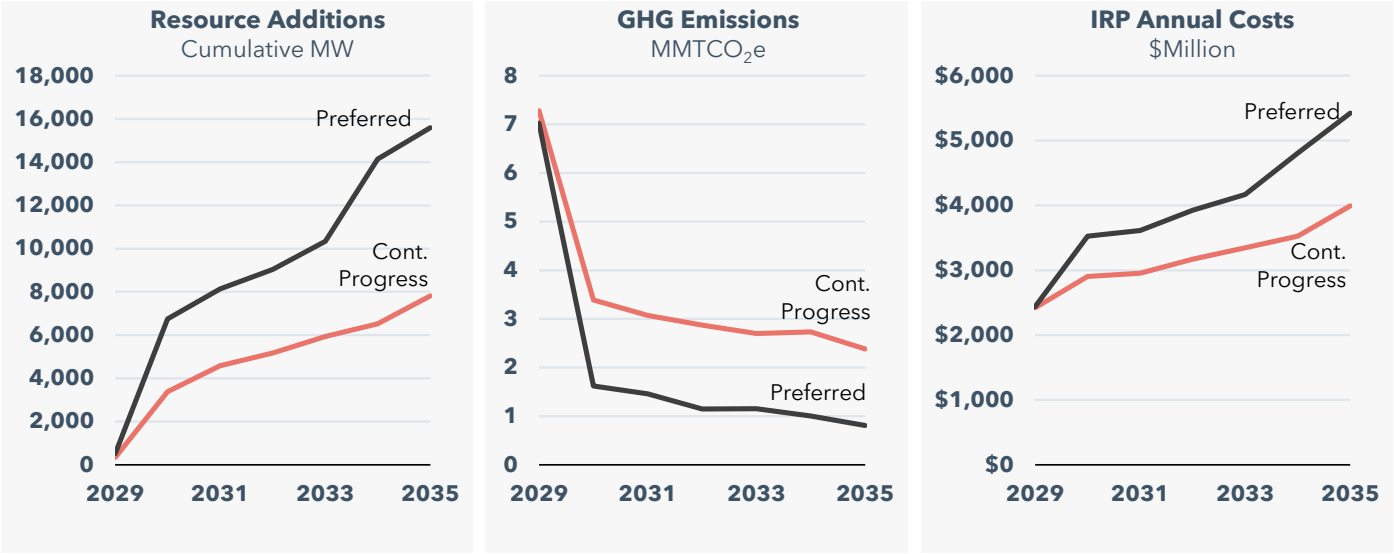
PGE, with stakeholder input, designed the Continued Progress Portfolio, which explores a path to reduce the risks identified in the HB 2021 Preferred Portfolio, while recognizing the affordability limitations established in HB 2021. This portfolio identifies 3,377 MW of resource additions needed by 2030 and over 5,000 MW by 2032 to continue to serve customers reliably while making significant progress towards HB 2021 emissions reductions targets. These portfolios are further discussed in Chapter 7.

The results, identified from both the Continued Progress Portfolio and the HB 2021 Preferred Portfolio, have directly informed the 2026 CEP/IRP Action Plan, which presents MW ranges as desired outcomes for PGE's continuing resource acquisition activities. The lower end of the resource ranges reflects the resource needs identified in the Continued Progress Portfolio. These and other actions are forecasted to reduce emissions from PGE's baseline by roughly 60% in 2030, exceeding 70% by 2035. The Action Plan also recognizes that within the near-term, circumstances, such as an extension of federal tax credits, may allow for additional procurement activities up to the amount identified in the HB 2021 Preferred Portfolio. In all cases, the Action Plan continues to emphasize the importance of cost-effective demand response, energy efficiency, and distributed

resources which support addressing PGE's resource needs while mitigating cost impacts to customers.

PGE's flexible Action Plan allows the Company to adapt to current planning conditions while prioritizing decarbonization, affordability, reliability, and management of execution risk. It also preserves flexibility within the Action Plan should market conditions evolve. If emerging technologies mature more rapidly, federal policy support changes, or broader macroeconomic conditions improve, PGE can increase procurement activity as needed to continue progress toward the greenhouse gas emissions reduction targets established under HB 2021. PGE will continue to prioritize transparency and engagement with customers, communities and regulators throughout the Action Plan time horizon as we assess procurement options and evaluate the resource outcomes that best meet customer and policy needs.

Figure 4. Generation Additions, Retail Emission Reductions and IRP Annual Costs of HB 2021 Preferred Portfolio and Continued Progress Portfolio



Clean Energy Infrastructure Must Include New Transmission

Like many regions across the country, the electric grid serving PGE customers was built to support a different economy, different patterns of electricity use, and a much smaller customer base. Today, energy usage is increasing due to home and transportation electrification, and growing demand from large energy users like advanced manufacturing and datacenters. At the same time, climate change is increasing extreme weather event frequency and driving higher seasonal peak demand. These forces reshape how the electrical system must operate, and place increasing stress on transmission infrastructure not designed for these conditions. Meeting these evolving needs, while also making continued progress toward Oregon's clean energy goals, requires both new generating resources and the ability to deliver those resources to customers when and where they are needed. Transmission infrastructure is the critical link between clean energy development and reliable electric service. Geographically diverse renewable resources are required to make clean energy portfolios reliable. By relying on multiple clean energy technologies and siting those

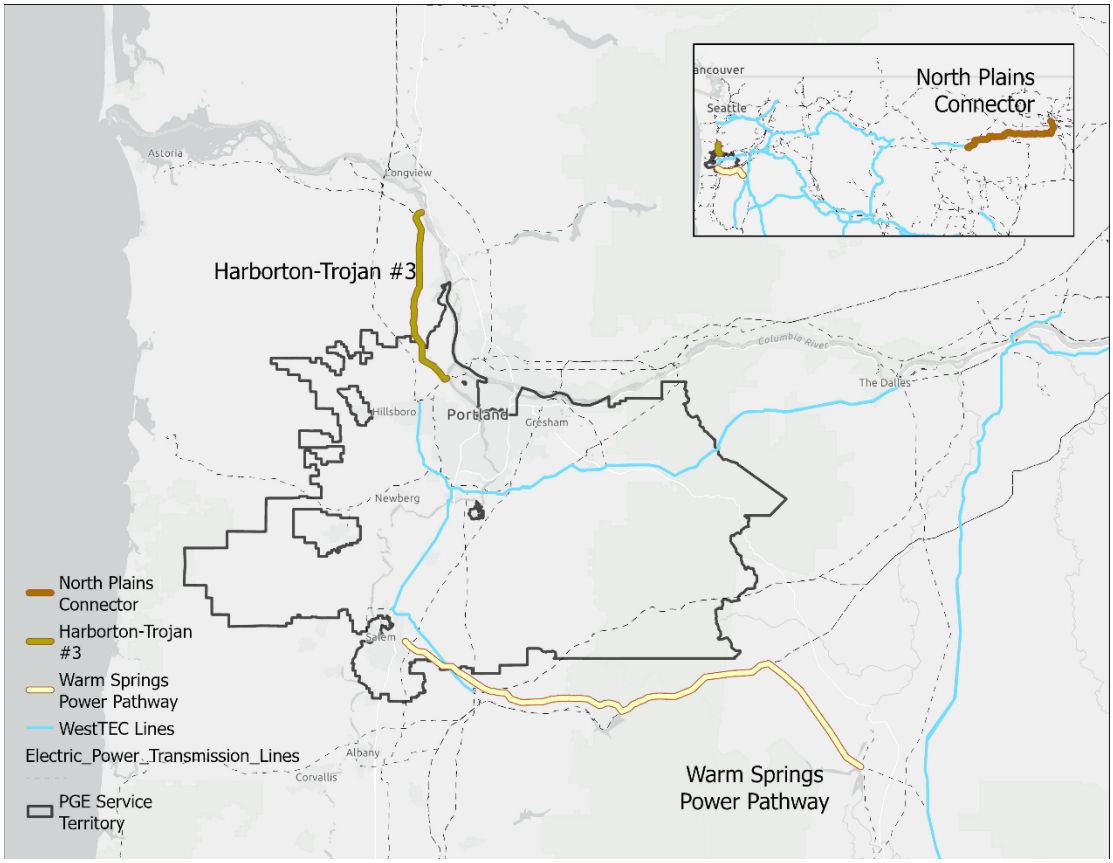
resources in diverse climates, PGE can manage the fundamental variability of resources such as wind and solar. PGE's transmission must access new geographies that enable diverse renewable resources and regional markets, to maintain reliability, manage costs, and reduce emissions as customer demand continues to grow. PGE's analysis consistently shows that a more interconnected grid improves system flexibility and strengthens the ability to respond to changing weather, market conditions, and customer needs.

PGE remains committed to maximizing existing infrastructure use before building new facilities. PGE is maximizing generation resources sited near existing facilities to share use of transmission facilities necessary for delivery to PGE's system. Investments in GETs, dynamic line ratings, advanced conductors, and other operational innovations increase the capability of today's transmission system and delay the need for more costly infrastructure, where possible. These tools provide meaningful benefits, increasing transmission capacity by up to 20% under particular weather conditions, and represent an important part of PGE's strategy to keep costs as low as possible. However, as much as these tools may reduce the scale and timing of future investments, they cannot eliminate the need for additional transmission. Across every planning scenario evaluated in this CEP/IRP, expanding transmission access remains essential to maintaining reliability and enabling continued clean energy additions.

This conclusion is consistent with findings from regional planning efforts, including WestTEC studies, state policy initiatives, and prior PGE planning analyses. The need for a larger and more capable transmission network reflects a broader regional reality: the clean energy transition depends on moving electricity over greater distances, accessing a more diverse set of resources, and creating stronger connections between regions. Strategic transmission investments also support affordability by increasing access to lower-cost energy supplies and improving participation in expanding regional energy markets.

Accordingly, PGE's Action Plan advances a portfolio of transmission solutions, including the Warm Springs Power Pathway (WSPP), North Plains Connector (NPC), Harborton-Trojan #3 and additional regional transmission projects. Together with continued deployment of GETs and participation in regional markets, these investments form the backbone of a reliable, affordable, and increasingly clean energy future. PGE is committed to ongoing engagement with customers, communities, stakeholders, Tribal partners, and regulators as these projects move forward and as the region works together to build the infrastructure necessary to support Oregon's energy future.

Figure 5. Three Transmission Expansion Activities Explicitly Included in 2026 CEP / IRP Action Plan



Affordable Electric Service Including All PGE Customers

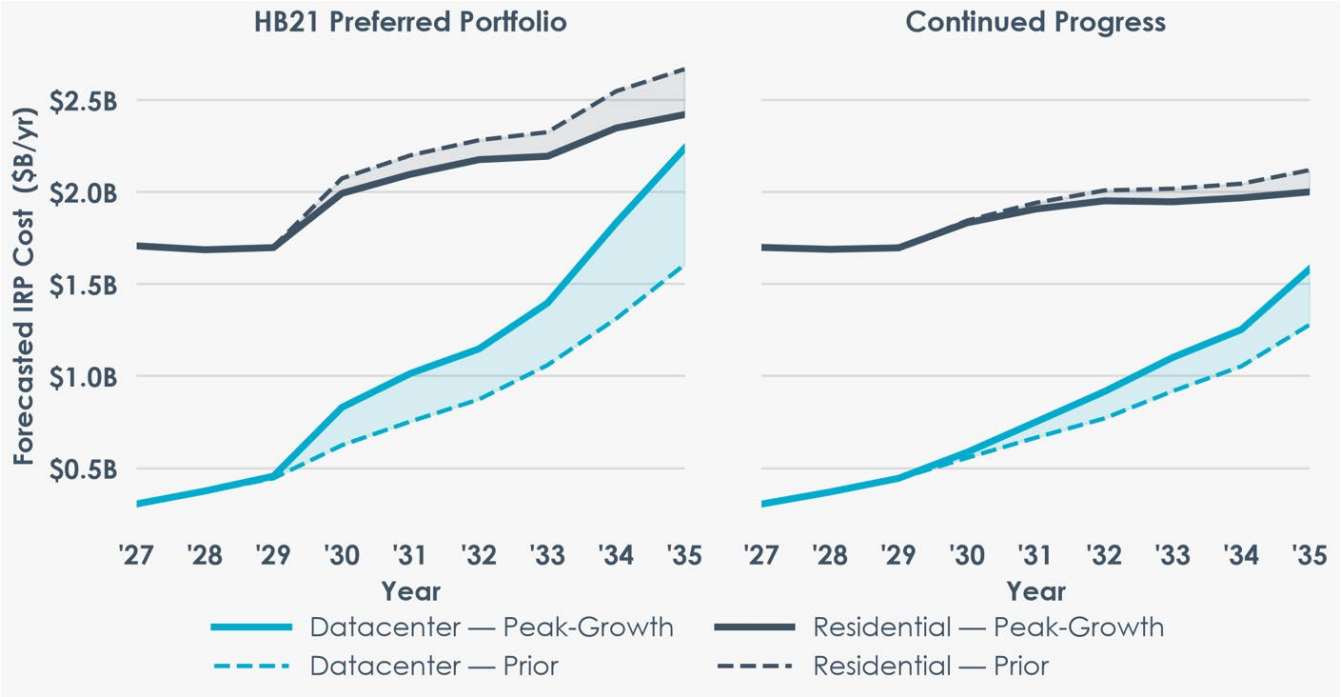
Meeting Oregon's growing energy needs requires continued investment in PGE's generation, transmission, and distribution infrastructure. PGE remains committed to making these investments using an approach that growth pays for growth. As new large customers locate within PGE's service territory, the company supports policies and regulatory frameworks that allow them to contribute appropriately to the infrastructure needed to serve them. This "growth pays for growth" principle was codified in law by Oregon's POWER Act in 2025.

In 2026, PGE implemented the POWER Act, introducing a new tariff structure that allocates growth-related costs to large-load customers through a Peak Growth Modifier (PGM) and related mechanisms. Under this new framework, datacenters contribute to investments needed to serve them, while an expanded customer base for system cost recovery results in lower bills for residential and small business customers. Through this approach, PGE can support continued customer growth while maintaining a strong focus on affordability for residential customers.

The 2026 CEP/IRP analysis finds that, when the cost of future growth is fairly allocated, affordability is supported for all customers over the long term. Customer growth increases retail sales over which system costs can be spread, and the costs of new infrastructure and clean energy resources are allocated to the customer classes creating the need for those investments. As a result, continued

growth and thoughtful cost allocation help maintain affordability for residential customers while supporting investment in the reliable and increasingly clean energy system that serves all customers.

Figure 6. Projected Residential and Datacenter IRP Costs Under New Cost Allocation Framework Compared to Prior Allocation Framework

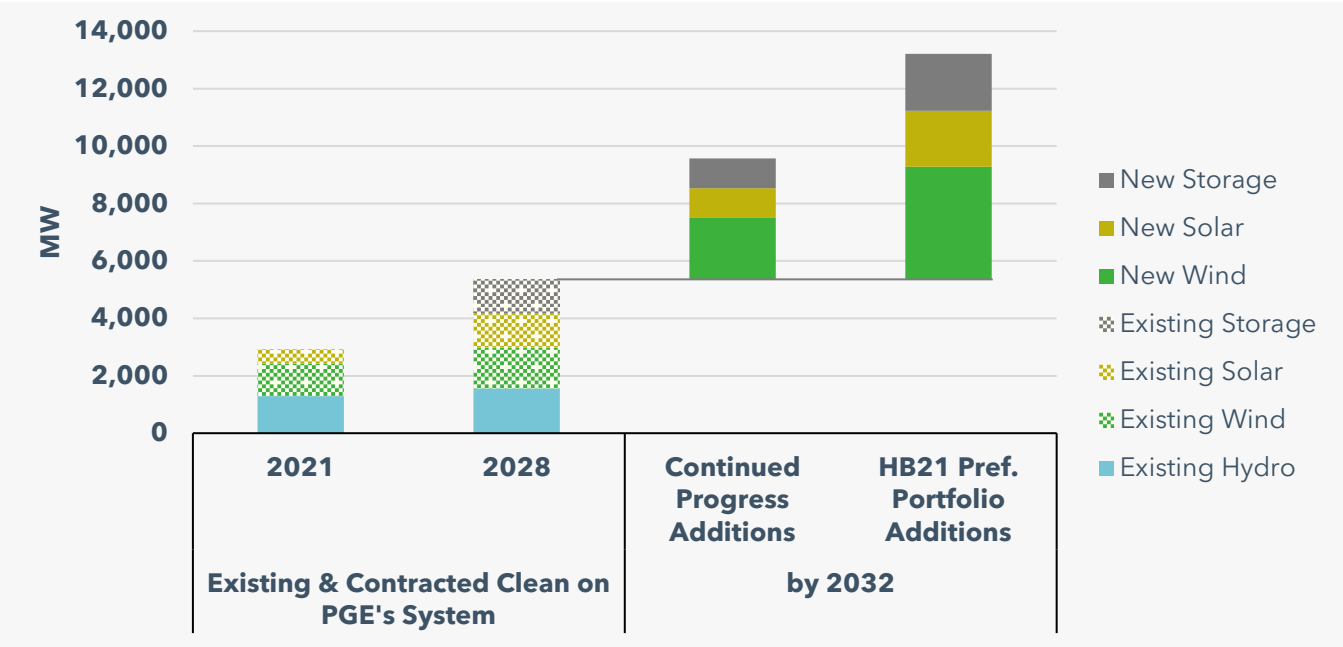


HB 2021 Preferred Portfolio, Alternate Portfolios and Action Plan Summary

The HB 2021 Preferred Portfolio identified in the 2026 CEP/IRP represents the least-cost, least-risk set of resources needed to continue to meet resource adequacy needs while fully decarbonizing in accordance with HB 2021 emission reduction targets. This portfolio identified an additional 6.7 GW needed by 2030 to reach 80% emissions reductions on a planning-basis, growing to 9 GW of resource additions by 2032 to stay on a GHG reduction glidepath as PGE progresses towards the next target in 2035. The HB 2021 Preferred Portfolio is required by Commission rules to limit emissions to the reduction targets identified in HB 2021, responding to the environmental priorities of the State of Oregon. However, achieving the Preferred Portfolio is dependent on accelerated transmission development and the availability of enough cost-effective resources. Given the cost concerns, which are amplified by the expiration of federal tax credits, and feasibility concerns of cumulative HB 2021 Preferred Portfolio resource development, PGE developed an alternative portfolio that continues to decarbonize but tempers the pace of resource additions through 2030, while still meeting the Company's obligations under HB 2021. This pace balances decarbonization with affordability and realistically addresses execution risk—easing the cost pressure on customers as PGE works to add a significant volume of renewables to the system.

The Continued Progress Portfolio was designed to continue PGE's decarbonization trajectory while managing increases of annual customer costs. Under this portfolio, PGE's compliance with HB 2021 is assumed to occur through continuous progress with the affordability and reliability off-ramps anticipated in the legislation. However, this portfolio still prioritizes very high renewable, storage, and DER adoption to meet needs, adding 3.4 GW by 2030, growing to 5 GW by 2032, a volume that is nearly double the generating capacity of PGE's entire owned and contracted portfolio as it exists today.[2] This portfolio also shows meaningful emissions reduction in the next five years, proving that decarbonization progress remains steady. Achieving this portfolio will require coordinated, full-throttle efforts by policy makers, regulators, and stakeholders to create conditions for siting, constructing, financing, and procuring clean resources at a faster pace than Oregon has seen to-date.

Figure 7. Near-Term Portfolio Impact Learnings



Across every scenario evaluated in this CEP/IRP, clean energy resources play a critical role in the resource additions identified as the most optimal for moving forward. However, resource availability, transmission constraints, rising development costs, and changing federal policies all influence the pace at which new resources can be added while maintaining affordability for customers. The Action Plan provides a practical pathway that continues emissions reductions, maintains reliability, and supports Oregon's economic growth while responding to these evolving realities, with the flexibility to pivot if macroeconomic conditions significantly change.

Informed by both the HB 2021 Preferred Portfolio and Continued Progress Portfolio, PGE has designed an Action Plan that serves as the procurement component of the Clean Energy Plan and Integrated Resource Plan. The Action Plan includes a range of opportunities, with the bottom end of

[2] As of December 31, 2025

the range representing the volumes of resources needed for the Continued Progress Portfolio, and the upper end the HB 2021 Preferred Portfolio. Consistent with customer feedback and the principles of least-cost, least-risk planning, the Action Plan prioritizes continued procurement of wind, solar, battery storage, energy efficiency, Virtual Power Plant resources, and transmission investments while advancing technologies and market participation to increase the value of those resources. Together, these actions position PGE to continue reducing emissions while meeting the needs of a growing customer base.

The analysis underlying this plan demonstrates that meaningful progress toward Oregon's clean energy goals remains achievable. At the same time, the pace of resource additions required to achieve HB 2021's 2030 emissions target presents substantial affordability, execution, permitting, transmission, and supply-chain challenges. Under current assumptions and modeling methods, the Continued Progress Portfolio achieves approximately 3.39 million metric tons of CO2e emissions in 2030, representing a reduction of approximately 58% from baseline levels. Under current assumptions, the Continued Progress Portfolio does not achieve the statutory 2030 emissions target. However, the Action Plan has been designed to allow for flexibility and the ability to continue to procure up to the volumes needed in the HB 2021 Preferred Portfolio should conditions in the planning environment shift in such a way that the cost of renewable resources decline, availability of renewable resources and transmission access increases, emerging technologies mature faster than anticipated and federal support for non-emitting resources is strong.

Future outcomes depend on factors including resource availability, federal policies, technology development, wholesale market conditions, and continued evolution of regional transmission systems. PGE’s ability to obtain affordable capital is essential for building the necessary infrastructure outlined in these plans, and this effort must be backed by appropriate regulatory and legislative policies. PGE continues to advocate for solutions to wildfire risk exposure and a utility structure that supports PGE’s ability to obtain capital at the lowest cost. Without improved risk exposure and the financial flexibility to access low-cost capital, PGE may be unable to fully advance the Action Plan discussed in Chapter 2.

A reliable grid needs to be resource adequate, with enough capacity and reserves to maintain balanced energy supply and demand to meet peak energy needs at any time and under all weather conditions. PGE's near-term Action Plan remains firmly centered on reliability. A reliable electric system is the foundation upon which clean energy progress is built, and Oregon’s economy can grow. As increasing quantities of renewable and distributed energy resources are integrated onto the grid, maintaining sufficient capacity, operational flexibility, and reserve margins become increasingly important. Reliability investments—including transmission expansion, Virtual Power Plant growth, regional market participation, customer flexibility programs, and continued use of existing generating resources—allow PGE to continue reducing emissions while maintaining safe and dependable service for customers under a wide range of operating conditions.

PGE's Action Plan reflects a practical and disciplined strategy for the years ahead. While supported by efficient access to low-cost capital, the Company will continue investing in clean energy resources, customer programs, transmission infrastructure, and grid innovation. PGE will fairly allocate growth related costs to the customers driving system expansion. Through these actions, PGE will continue making measurable progress toward a cleaner energy future while maintaining

the affordable and reliable electric service that customers expect. As technologies, markets, and policies evolve, PGE will remain positioned to accelerate decarbonization opportunities that can be achieved in the best interests of customers and communities.

1 Clean Energy Plan

This chapter describes how PGE plans to serve customers reliably and affordably, while making progress toward the state's clean energy and greenhouse gas reduction requirements established by House Bill 2021.[3] This plan provides a roadmap of the resources, investments, and actions needed to reduce emissions over time and evaluates their implications for customer costs. It also examines the key uncertainties, dependencies, challenges, and barriers that could affect the utility's ability to achieve the state's clean energy targets and identifies actions that can help address them.

Chapter Highlights

- PGE has made significant progress since 2021. PGE has added and contracted for over three (3) gigawatts of utility-scale clean energy to the system and has reduced emissions associated with retail service by 25% compared to the baseline established in HB 2021.
- The planning environment has changed, creating significant headwinds for PGE's decarbonization journey. Changing federal policy, increased competition for resources, transmission constraints, and unresolved exposure to wildfire risks have impacted PGE's path forward. These dynamics increase the importance of PGE's access to financing options that secure the capital needed for customer investments at the lowest possible cost. Finance constraints could affect the pace and sequencing of actions needed to maintain reliability, manage affordability and continue progress towards clean energy targets.
- PGE is introducing two (2) distinct planning portfolios that inform the near-term Action Plan. PGE has identified a HB 2021 Preferred Portfolio that achieves the emissions reduction targets as stated in HB 2021, and has also identified a Continued Progress portfolio, which better balances decarbonization progress with affordability.
- Transmission plays an essential role in decarbonization. Access to diverse resources and geographic locations becomes increasingly important as PGE continues to procure the clean energy resources needed to serve customers and increases participation in regional markets.
- PGE's customers and stakeholders have been clear that affordability is a primary priority. PGE's near-term Action Plan seeks demand-side, supply-side, and transmission portfolio additions with prioritization of the most cost-competitive opportunities with flexibility to adjust as the planning environment evolves. This plan focuses on flexibility, allowing PGE to act quickly and secure the lowest costs possible for customers.

PGE has powered Oregon communities for more than 130 years, providing the reliable, affordable, and safe electricity that supports homes, businesses, and the economic vitality of the region. PGE is leading the way to a clean energy future and has made remarkable progress towards Oregon's clean energy goals. Since the adoption of HB 2021, PGE's addition of 3 GW of renewables to the system have directly reduced emissions on PGE's system. PGE has reduced emissions served to

[3] From a regulatory compliance perspective, Chapter 1 does not fully stand alone as the CEP. Chapter 1 summarizes key CEP requirements pursuant to OAR 860-090-0100, but the entire 2026 CEP/IRP should also be read as including the CEP.

retail customers by 25% compared to HB 2021's baseline. These reductions have been achieved while simultaneously serving significant load growth, evidencing PGE's ability to serve customers while advancing the clean energy goals that are shared by customers, the State and the Company.

Oregon and the broader Pacific Northwest are experiencing significant energy transformation. Electricity demand is growing, the region's historical surplus of energy and transmission capacity is tightening, extreme weather is increasing demands on the power system, and customers and communities increasingly depend on electricity to support economic growth and essential services. At the same time, Oregon has established ambitious requirements to reduce greenhouse gas emissions from electricity generation. The path forward will require significant collaboration with communities and stakeholders, additions of generation, storage, transmission, and other grid infrastructure, together with new approaches to customer participation and regional coordination. It will also require careful sequencing of investments to provide the benefits of the transition directly to customers while maintaining reliability and managing costs.

PGE's second Clean Energy Plan (CEP) builds upon substantial progress already underway and establishes a strategy for continuing Oregon's transition toward a clean electricity system. PGE prepares and submits a CEP to the Oregon Public Utility Commission (OPUC) every three (3) years. Consistent with Oregon's Clean Energy for All law, HB 2021, the CEP describes PGE's progress toward statutory emissions reduction requirements and identifies actions necessary to continue that progress. Importantly, the CEP considers not only emission reductions, but also the affordability, reliability, resilience, and community impacts associated with the pace and sequencing of the transition.

PGE develops its CEP alongside its Integrated Resource Plan (IRP), which evaluates a least-cost, least-risk strategy for serving customers' demand in the coming years. The objectives of these two (2) documents are fundamentally interconnected. The CEP builds upon the analysis in the IRP to describe how PGE's resource strategy advances Oregon's decarbonization requirements.

1.1 PGE's Forward-Looking Approach

PGE's clean energy transition is well underway. The Company's strategy is designed around a central objective: deliver a reliable and increasingly clean electricity system, which best balances costs and risks to customers, while building the infrastructure necessary to support Oregon's long-term growth and prosperity. The operating and planning environments have changed significantly since the passage of HB 2021. The results of PGE's analysis show that the necessary strategy for achieving stated emissions reductions targets in this current environment includes execution and affordability risks, reinforcing the importance of being prepared to act, while remaining flexible as conditions evolve.

The 2026 CEP/IRP identifies a HB 2021 Preferred Portfolio that requires 6,747 MW of resource additions needed to achieve an 80% reduction in emissions compared to the baseline established in HB 2021. However, this analysis also suggests that volume likely needs to be tempered to a quantity that is executable while addressing customer affordability concerns.

Given the significant resource needs of the HB 2021 Preferred Portfolio, PGE designed the Continued Progress Portfolio. The Continued Progress Portfolio, discussed further in Chapter 7,

identifies a path to mitigate the execution and affordability risks identified in the HB 2021 Preferred Portfolio, while achieving significant emissions reductions over time, adding 3,377 MW of resources by 2030.

The results, identified from both the Continued Progress portfolio and the HB 2021 Preferred Portfolio, have directly informed the 2026 CEP/IRP Action Plan. The lower end of the resource ranges reflects the resource additions identified in the Continued Progress portfolio. The Action Plan also recognizes that within the near-term, circumstances may allow for additional procurement activities up to the amount identified in the HB 2021 Preferred Portfolio. Figure 8 details the near-term actions the Company has identified based on extensive portfolio analysis.

Figure 8. PGE's Near-Term Action Plan

1. **Energy Efficiency Action**
   - Fund Energy Trust of Oregon to support acquiring cost-effective energy efficiency
2. **Virtual Power Plant Action**
   - Pursue available cost-effective flexible load and dispatchable distributed resources
   - Maximize resource value of customer sited solar
3. **CBRE and SSR Actions**
   - Seek projects with tangible community benefits across procurement pathways
   - Acquire SSR-eligible resources by 2030
4. **Utility Scale Resource Actions**
   - Acquire firm and dispatchable capacity contracts
   - Acquire approximately 3,000 MW of renewables that maximize use of existing transmission plans
   - Acquire additional 1,800 to 5,700 MW of renewables, informed by resource acquisition progress
5. **Transmission Actions**
   - Leverage GETs
   - Support advancement of Warm Springs Power Pathway, North Plains Connector and Harborton-Trojan #3 projects
   - Maintain options for additional transmission projects
6. **Resource Planning Action**
   - File 2026 CEP/IRP Updates in 2027 and 2028
   - File 2029 CEP/IRP

This CEP/IRP seeks to prioritize these durable investments identified in the Action Plan, while maintaining flexibility as technology, customer needs, markets, and public policy evolve. PGE is seeking acknowledgement of this near-term Action Plan, as well as the long-term resource strategy described in Section 1.5.1, from the OPUC to support PGE's path forward.

1.1.1 Building from a Solid Foundation

PGE enters this planning period with a diverse portfolio and substantial experience integrating clean energy into the regional grid. The Company's system includes more than 3,500 MW of owned-generation capacity spanning hydroelectric, wind, solar, natural gas, and coal resources, long and short-term power purchases, and access to regional wholesale markets.

PGE has progressively transformed this portfolio through investments in renewable resources, energy storage, flexible generation, customer resources, and grid infrastructure. The Company also participates in regional energy markets and maintains transmission capabilities that connect customers to resources throughout the Pacific Northwest and the broader western grid.

This existing portfolio provides a reliable platform, but the resources and infrastructure necessary to serve customers in the coming decades will be different from those that have historically served the region. The Pacific Northwest can no longer assume abundant surplus energy, capacity, or transmission will be available when needed. New generation resources face increasingly long interconnection, permitting, transmission, and equipment lead times. At the same time, customer demand and resource adequacy needs are growing.

PGE's first combined CEP/IRP, filed in 2023, established a strategy for meeting customer needs while progressing toward HB 2021's 2030, 2035, and 2040 emissions reduction requirements. The 2023 CEP/IRP Update filed in 2025 refreshed forecasts and planning assumptions and identified a revised Preferred Portfolio as system conditions evolved.

The 2026 CEP/IRP builds on the 2023 CEP/IRP and following filings. It incorporates updates to key elements, including but not limited to customer demand, resource adequacy requirements, market conditions, resource costs, transmission constraints, technology developments, and policy requirements. This CEP/IRP identifies the actions PGE should take in the near-term, while preserving the flexibility to adapt to an uncertain future.

The result is a plan where the focus goes beyond solely identifying future resource needs to include a realistic, flexible execution strategy. This plan sets the foundation for PGE to secure resources, transmission access, infrastructure, and development opportunities on the timeline needed to reliably and affordably meet customers' needs while making continuous progress toward emissions targets.

1.1.2 Emission Reduction Approach

PGE remains committed to decarbonization. The Company plans to continue making meaningful progress toward Oregon's emission reduction requirements while maintaining the reliability and affordability that customers expect.

Decarbonization, however, is not achieved through emissions targets alone. It requires replacing the energy, capacity, flexibility, and reliability services historically provided by emitting resources with a portfolio of clean resources and supporting infrastructure capable of serving that energy to customers.

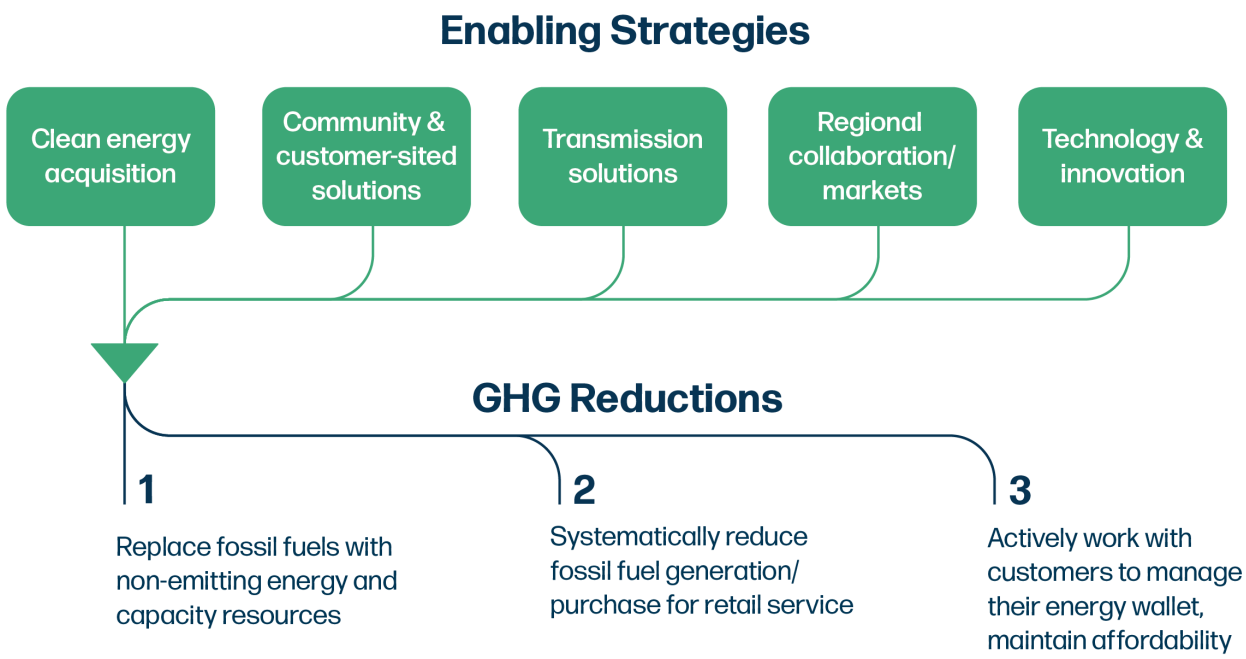
PGE's approach integrates emissions reduction with reliability, transmission availability, customer demand, and affordability. This allows the Company to pursue durable emissions reductions while

managing risks associated with an increasingly constrained and interconnected regional power system.

Figure 9 depicts three core strategic principles underlying this strategy:

1. Replace fossil fuels generation and purchases with non-emitting energy and capacity resources.
2. Systematically reduce the generation and purchase of fossil fuels for Oregon retail customers.
3. Work with customers to manage their energy use and expenditure.

Figure 9. Enabling Strategies for GHG Reductions



Together, these principles recognize that the clean energy transition is fundamentally a transformation of the electric system, not simply a substitution of one generation technology for another. PGE's strategy is to build the generation, transmission, storage, customer capabilities, and regional partnerships necessary to make that transformation reliable, affordable, and durable for Oregon customers.

1.1.3 Key Decarbonization Strategies

PGE is pursuing five complementary strategies designed to reduce emissions while preserving flexibility as customer needs, technologies, and regional conditions evolve.

1.1.3.1 Clean Energy Acquisition

Clean energy acquisition remains the foundation of PGE's resource strategy. PGE's planning analysis demonstrates that multiple gigawatts of non-emitting energy and capacity will be required

to serve growing customer demand, maintain reliability, and make sustained progress toward Oregon's emissions reduction requirements.

PGE's strategy is not simply to acquire clean energy, but to assemble a diversified portfolio that provides the energy, capacity, flexibility, and operational capabilities necessary to reliably serve customers as reliance on emitting resources declines. Section 1.2.2 describes PGE's recent clean energy acquisitions and the actions underway to continue this transition on a least-cost, least-risk basis for customers.

1.1.3.2 Community and Customer-Sited Solutions

Customer and community resources are an increasingly important component of PGE's resource portfolio. PGE's Virtual Power Plant (VPP) coordinates customer programs to both reduce demand and increase energy on the system during periods of peak demand.

By managing when electricity is produced, stored, and consumed, the VPP can reduce or defer the need for certain infrastructure investments that would otherwise be needed to meet peak demand conditions. The VPP also creates opportunities for customers and communities to participate directly in, and receive value from, the clean energy transition.

PGE's strategy is to further integrate these capabilities into system and resource planning so that customer resources complement utility-scale generation, storage, transmission, and distribution investments. This work will build on the progress made to date, meeting 13% of peak capacity need with VPP resources, and further progress towards the Company's goal of meeting 25% of peak capacity need by 2030.

1.1.3.3 Technology and Innovation

Innovation is a key element of maintaining affordability and reliability. As electricity demand grows and the power system becomes more complex, PGE is deploying technologies that increase the capability and utilization of infrastructure customers have already invested in, while improving the performance of future investments.

Initiatives like flexible load interconnection analysis and the deployment of Grid Enhancing Technologies (GETs), discussed further in Section 1.3.3, demonstrate this approach and the value that can come from unlocking additional capacity in existing infrastructure. Under the right conditions, GETs can increase the capacity of transmission lines by up to 20%.

PGE will continue to evaluate and deploy innovation where it can deliver measurable customer value. The Company will pursue innovative opportunities to maintain reliability, accelerate clean energy integration, or avoid or defer higher-cost infrastructure solutions.

1.1.3.4 Regional Collaboration and Markets

PGE's customers benefit from being connected to a diverse and increasingly integrated western electricity system. Markets can make it possible to power a home with solar from Eastern Oregon during the day, wind from the Columbia River Gorge in the evening, and batteries from California at

night. Greater regional coordination allows PGE to optimize its own resources while accessing a broader portfolio of generation and flexibility across the west.

PGE signed an Extended Day-Ahead Market (EDAM) implementation agreement in 2024 and began participating on October 1, 2026. EDAM allows PGE to access more energy across a larger geographic footprint. Of critical importance to PGE, is EDAM's delivery of clean energy resources across vast geographies to load. Further market integration is expected to increase utilization of existing infrastructure, better manage transmission congestion, and reduce costs through increased efficiencies of a larger group of utilities working together to serve customers across the region.

Regional market participation also complements PGE's clean energy strategy. Significant quantities of renewable generation and storage have been added across the West, and broader market participation can improve access to diverse resources. At the same time, evolving greenhouse gas accounting and emissions reporting frameworks are expected to improve transparency regarding the emissions associated with electricity transfers across regional markets.

PGE views regional markets as one component of a broader regional strategy that includes coordinated planning, resource adequacy, transmission development, and collaboration with neighboring utilities and other regional partners.

1.1.3.5 Transmission Solutions

Transmission is foundational to PGE's decarbonization strategy. Without it, a regional network of wind, solar, and battery storage cannot effectively serve customers with clean energy.

The Pacific Northwest is transitioning from a region that historically benefited from available transmission and surplus generating capacity to one in which both are increasingly constrained. Existing regional transmission capability is highly subscribed, and many transmission lines are nearing the end of their expected lifespan. There is fierce competition for what little capacity is available. At the same time, major transmission projects can require many years to plan, permit, finance, and construct.

These conditions require PGE to take a more proactive and portfolio-based approach to transmission. PGE intends to pursue multiple pathways to expand access and preserve future options, including acquiring transmission rights on third-party systems, optimizing existing rights and infrastructure, deploying GETs, upgrading PGE-owned facilities, participating in regional transmission projects, and evaluating direct investment or ownership, where doing so provides strategic and economic value to customers.

PGE will coordinate these investments with its resource strategy so that transmission planning and resource acquisition increasingly operate as an integrated portfolio. This approach recognizes that securing transmission capability early can preserve access to lower-cost resources, improve resource adequacy, reduce exposure to constrained regional markets, and enable the clean energy resources necessary to serve customers over the long-term.

1.2 Detailed Progress and Milestones

PGE leads its peer utilities, ranking #1 for lowest carbon intensity,[4] which has declined 11% from 2021 to 2025.

The Company's remarkable progress was made during a period of demand growth, which PGE has largely served with clean energy. At the same time, the Company has minimized impacts on customers' bills through PGE's value-focused resource acquisitions, capture of tax credits, and grid enhancing technology innovations.

1.2.1 Reductions in Greenhouse Gas (GHG) Emissions

Broadly, decarbonization planning centers on customers' needs as PGE plans for investments in new resources and the grid that support progress towards HB 2021 emissions targets in 2030, 2035, and 2040. As noted above, approaches to reducing emissions involve reducing and/or replacing fossil fuel generation and purchases with reliable non-emitting energy and capacity, as well as working with customers to help manage energy use and total energy expenditures, especially with growing demand.

At the close of 2025, PGE disclosed emissions of 6.0 million metric tons of CO_2e—a 25% reduction from the baseline established in HB 2021 of 8.1 million metric tons of CO_2e (the average of emissions reported in 2010 through 2012). Emissions associated with retail customers has been on a declining trend since 2010, a direct result of PGE's investment in renewable resources and significant contributions from PGE's customers. Figure 10 reports the historical variability of year-to-year reported greenhouse gas (GHG) emissions, with an overall declining trend from 2010 to 2025.[5]

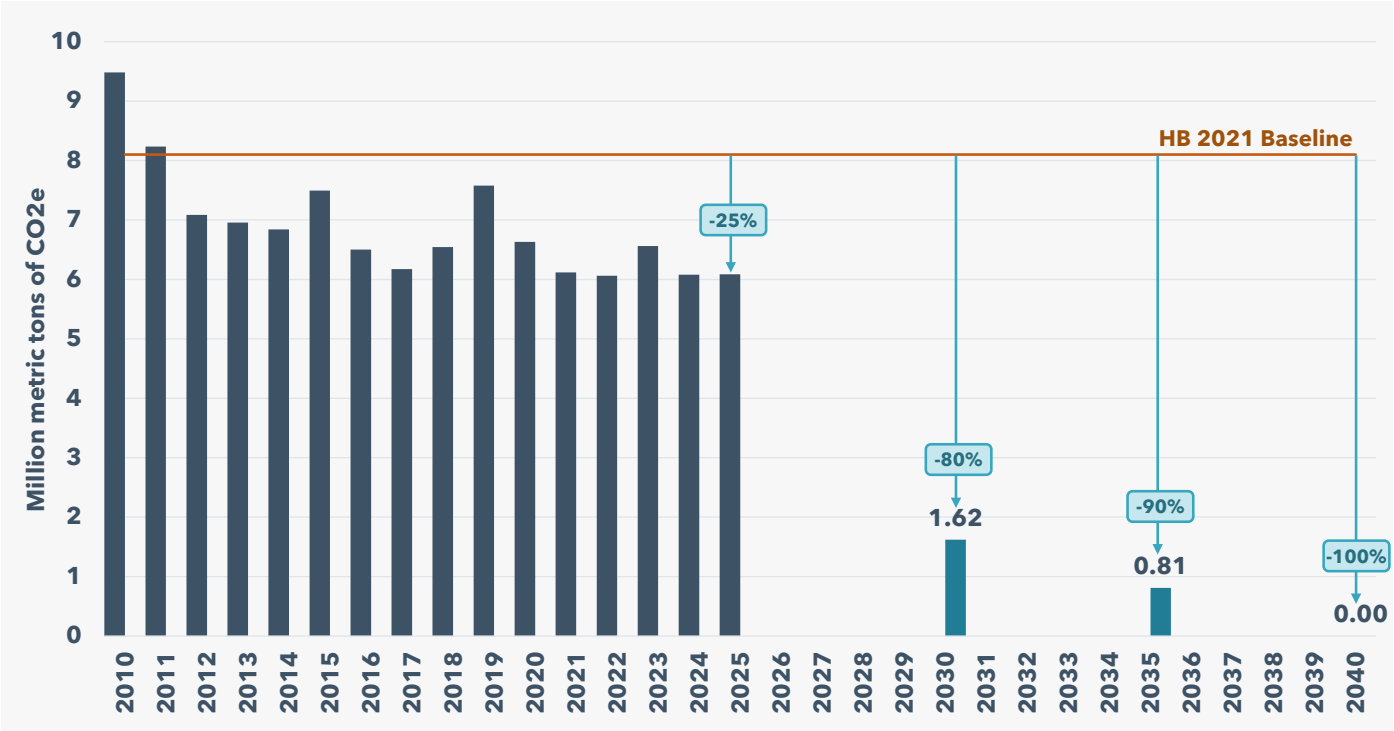
GHG emissions from generation and power purchases fluctuate year to year, due to variations in economic conditions, temperature, conditions influencing variable renewable energy, water conditions, and other external factors. For example, higher-than-expected temperatures can increase the need for air conditioning, which increases demand and the emissions associated with serving retail electrical load.[6] Water conditions can change hydroelectric power availability, with increasingly low water years as the climate continues to change, such as was the case in 2023, increasing reliance on GHG emitting generation. An increase or decrease in macroeconomic activity can further alter energy demand and the emissions associated with serving retail load.

In recent years, contracts for energy and capacity have played an important role in supporting near-term reliability as the system significantly changes while decarbonizing. Hydro and natural gas capacity contracts provide dependable capacity, operational flexibility, and seasonal reliability value while additional clean resources, customer flexibility, and transmission solutions are

[4] Based on the utility/proxy peers reported in the National Public Utilities Council Fall 2025 Annual Decarbonization Report.
[5] ORS 469A.420(4)(a) requires PGE to provide the OPUC with its two most recent annual emissions reports filed with the Oregon Department of Environmental Quality (ODEQ) reflecting emissions associated with retail sales. Information from these reports for years 2024 and 2025, as well as reports going back to 2010 aligns with the historical data shown in GHG emissions-related figures, and can be found on ODEQ's website: ODEQ, Greenhouse Gas Emissions Reported to DEQ, available at: https://www.oregon.gov/deq/ghgp/Pages/GHG Emissions.aspx.
[6] Since non-emitting resources dispatch first, an increase in load above the expected basis would likely be met by gas, coal or market purchases.

developed. These contracts help maintain reliability and reduce reliance on short-term market purchases, which can be less dependable during stressed system conditions. They also preserve the Company's longer-term direction toward an increasingly clean resource portfolio.

Figure 10. PGE's Historical GHG Emissions for Oregon Retail Load Service and HB 2021 Targets



The CEP/IRP assumes demand will be higher in the future even after cost-effective energy efficiency programs and distributed energy resources (DERs) are incorporated into PGE's system. Instead, emission reductions will come from acquiring new non-emitting resources while optimizing their location and access to transmission capacity.

Since total emissions naturally rise and fall with how much electricity customers use, looking at total emissions alone can be misleading—a hot summer with high demand could make the numbers look worse even if the power mix did not change at all.

That is why emissions intensity (how much CO_2e is emitted per unit of electricity delivered) is a useful decarbonization metric: it strips out the effect of demand going up or down, providing a comparison of power mix itself, regardless of whether more or less of it was used.

Figure 11. PGE's Historical GHG Emissions Intensity

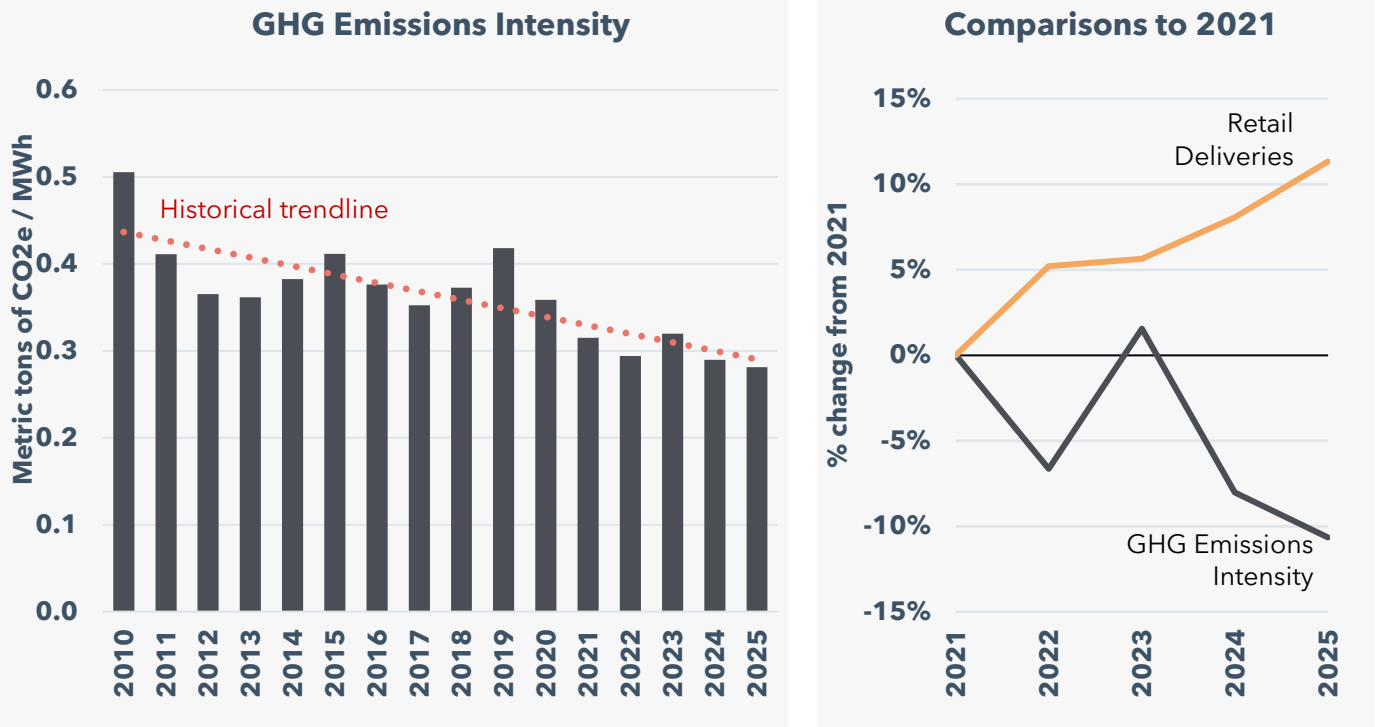


Figure 11 shows PGE's Oregon retail GHG intensity declining from 2010 through 2025, demonstrating progress toward advancing a resource mix that is increasingly clean. Since 2021, GHG intensity has dropped 11% while PGE load and energy deliveries to retail customers have grown. This decline demonstrates PGE's commitment to meeting new load primarily with clean energy. While GHG intensity provides useful information, HB 2021 requires an absolute reduction in utility GHG emissions, not a decrease in GHG intensity.

For the CEP, PGE is required to compare any GHG emissions reports filed with ODEQ since the CEP with the emissions forecast in the CEP.[7] Reported emissions for 2024 and 2025 are higher than those forecasted for retail sales for those same years from the 2023 CEP/IRP.[8] The retail sales emissions forecast for planning at that time assumed average conditions, as well as some level of emissions reductions from last known historical data available at that time. In actual reporting, the non-linear historical trend of Figure 10 is due to a range of factors, such as:

- Weather variation: for example the same power system will produce different emissions levels in a mild vs. extreme temperature year, such as was the case with 2023.
- Procurement timelines: clean energy acquisition enabling emissions reductions may occur in blocks that could lead to staircase-like GHG reductions over time. From a portfolio perspective, balancing regulatory, operational, financial, and resource procurement risks informs when non-emitting resources are able to be acquired over time.

[7] 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.
[8] PGE 2023 CEP/IRP, Figure 27, PGE_2023_CEP-IRP_REVISED_2023-06-30.pdf.

- Unexpected economic conditions impacting load: higher or lower than expected load may impact GHG emissions. Higher loads could arrive from faster-than-expected customer growth and/or faster-than-expected electrification.

Due to these kinds of annual variations, the OPUC has stated that utilities should "achieve the 2030 and 2035 clean energy targets under typical or expected weather and hydro conditions…"9 This implies that emissions may be higher or lower than the HB 2021 targets due to variability, but under average conditions meet the targets. As described above, actual weather and temperature conditions for recent reported data years were considered above average, resulting in greater reliance on emitting resources than forecasted in previous CEP/IRP. Despite these conditions, PGE has made significant progress toward decarbonization, resulting in the 2025 reported GHG emissions being 25% below HB 2021's 2010-2012 average baseline level.

1.2.1.1 Renewable Energy Certificates

In response to Commission Direction #6 in LC 80 Order No. 24-096,[10] PGE described the future requirements of demonstrating compliance with HB 2021 emissions targets in the January 2026 Roundtable[11] and included a discussion to clarify information about emissions reductions, clean energy and renewable energy certificates below. PGE further expanded on this discussion in Appendix N.

PGE reports emissions to the Oregon Department of Environmental Quality (ODEQ) based on defined rules in OAR Chapter 340, Division 215. All generating resources, including emitting and non-emitting, are required to be reported to ODEQ.

HB 2021 and the rules addressing emissions reporting and compliance are distinct from Oregon's clean energy programs such as the Renewable Portfolio Standard (RPS). For the RPS, renewable energy certificates (REC) are used for compliance, as they support contractual claims to renewable energy but do not support emissions compliance. As memorialized in Order No. 24-002, the Commission stated: "The text and context of the statute point unambiguously to the conclusion that compliance with HB 2021's emissions reductions requirements need not be demonstrated through REC retirement. HB 2021 requires us to consider and report the emission attributes of the underlying generating resource, and as such, emissions reported for compliance with HB 2021 can only reflect the underlying generating resource."[12] Thus, the considerations for RECs are not pertinent to HB 2021 compliance.

1.2.2 Deploying Clean Energy

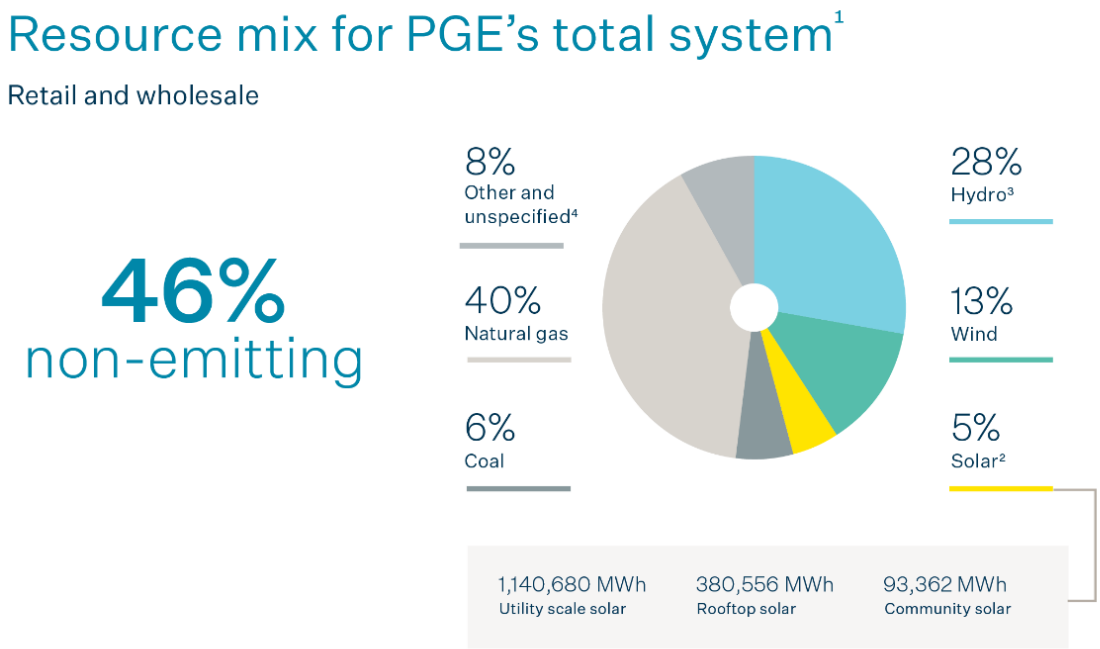
Since 2021, PGE has added and contracted for 3 GW of clean energy, allowing PGE to supply 46% of its energy from non-emitting resources in 2025. Additionally, 1,015 MW of clean energy resources are in development and scheduled to come online by 2028. These clean energy

[9] 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.
[10] https://apps.puc.state.or.us/orders/2024ords/24-096.pdf
[11] Appendix C
[12] https://apps.puc.state.or.us/orders/2024ords/24-002.pdf.

deployments enabled PGE to achieve the #1 ranking for lowest carbon intensity amongst peer utilities in the nation.[13]

This shows that PGE is meeting the increased demand for electricity on its system with increasingly clean resources. PGE's deployment of clean energy reflected consideration of customer affordability, as the company balanced procurement with pressure on customer bills.

Figure 12. PGE Resource Mix



1. *Percentages above represent 2025 resource mix from PGE's total system load, inclusive of wholesale and retail volumes. The percentage of 2025 retail loads as defined by Oregon Department of Environment Quality (ODEQ), which excludes wholesale sales, served by non-emitting resources is 40%. This resource mix does not include battery storage. Refer to the appendix for additional information.*
2. *Rooftop solar and community solar are based on gross generation, which is total energy generated before any on-site customer usage.*
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).*

[13] Based on the utility/proxy peers reported in the National Public Utilities Council Fall 2025 Annual Decarbonization Report.

Figure 13. Clean Energy Additions Since 2021

Clean energy additions since 2021

Achieving emissions reduction requires steadily adding renewable energy, battery storage, energy efficiency and customer-sited resources to our portfolio.

PGE has added and contracted for over 3 gigawatts of utility scale clean energy since 2021. Renewables in PGE's total system load have grown by 37% since 2021.

Wind (311 MW)
- Clearwater 2024: 311 MW

Utility-scale solar (895 MW)
- 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
- Biglow Solar 2027: 125 MW
- Wheatridge Expansion 2027: 240 MW

Hydro contracts (688 MW)
- Mid-C PPA 2023 (2024-2025): 76 MW
- Mid-C PPA 2023 (2024-2026): 434 MW
- Douglas PUD 2024 (2026-2030): 79 MW
- Mid-C PPA 2026 (2027-2036): 99 MW

Batteries (1,184 MW)
- Wheatridge Battery 2022: 30 MW
- Constable 2024: 75 MW
- Sundial 2024: 200 MW
- Coffee Creek 2024: 17 MW
- Seaside 2025: 200 MW
- Meadowlark 2027: 200 MW
- Biglow Battery 2027: 125 MW
- Wheatridge Expansion 2027: 125 MW
- Nottingham 2028: 200 MW
- Other BESS facilities: 12 MW

Ownership type
- Co-owned
- Customer owned
- PGE owned
- Third-party owned
- Mixed ownership

Next steps:

The Company is building on this progress with its 2025 All-Source RFP. PGE plans to contract as much as 2,500 MW of clean energy from its final shortlist in Q1 of 2027.

*** Procured by customers through Green Future Impact program.*

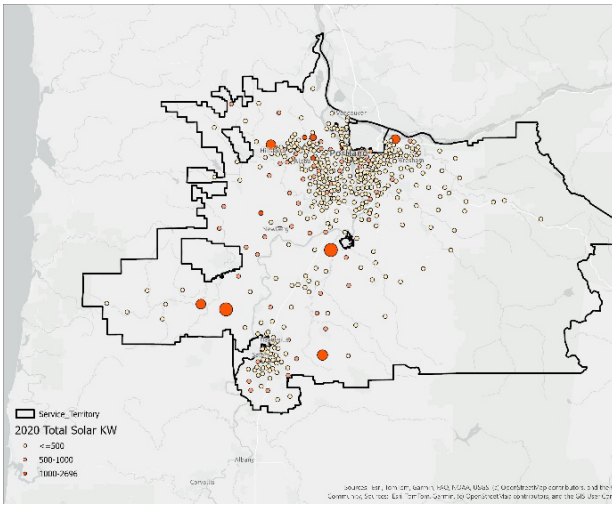
1.2.3 Leading Customer Programs

PGE's customers provide valuable system and local benefits through participation in PGE's customer programs. These programs provide customers with opportunities to manage energy use and costs, adopt clean-energy technologies, and contribute to system reliability and flexibility. These offerings include flexible-load and transportation electrification, distributed generation, voluntary renewable energy and energy-efficiency programs. Customer programs include:

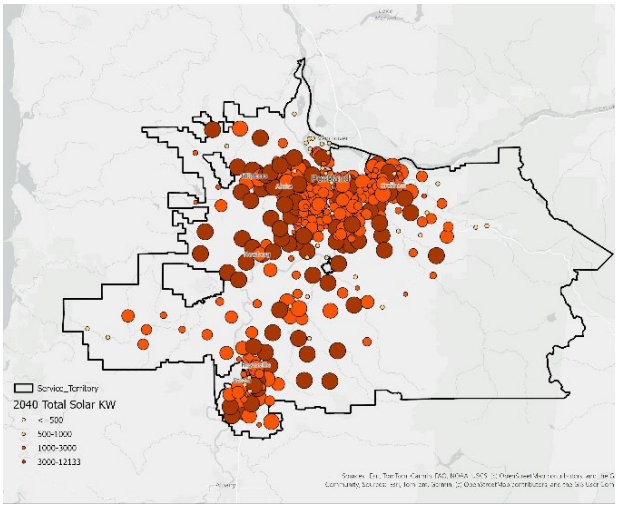
- Load flexibility and grid edge innovation. PGE depends on these programs in times when energy is needed the most. Today, PGE can meet 13% of its historical peak capacity electricity need through customer resources enabled by VPP. PGE's vision and advancement for the VPP is described in the next section.
- Electric vehicles. PGE helps customers, businesses, and communities switch to electric transportation through EV education and charging support, offering rebates, bill credits and community-focused projects and funding.
- Customer and on-system solar. PGE supports customers who want to generate or access local solar energy through net metering, rooftop solar guidance, battery pairing opportunities, and Oregon's Community Solar Program which helps homeowners, renters, businesses, and income-qualified customers participate in Oregon's clean energy future. Since the beginning of 2021, the Oregon Community Solar Program has grown to 30 operational projects, with a total capacity of 66 MW in PGE's service area.[14] Small-scale solar resources and rooftop solar continue to play a critical role in the service territory, currently contributing 381 MW and forecasted to continue to grow over the next 10 years and beyond.

Figure 14. Customer Solar PV Load and Projection

2020 - Existing Installed



2040 - Modeled



- Voluntary renewables programs. PGE residential and business customers can opt in to voluntary renewable programs. Approximately 25% of PGE customers enroll in voluntary renewables programs that can also help fund new small-scale renewable projects in Oregon.

[14] Based on the Oregon Community Solar Program August 2026 Bi-Monthly report.

For the 16th straight year, PGE ranked first in the nation for customer participation in voluntary renewable energy programs.[15]

- Energy efficiency and weatherization via Energy Trust programs. Directly funded by PGE customers, $79M of incentives were provided to eligible customers in 2025, providing a robust suite of efficiency, weatherization, and DER financial incentives.

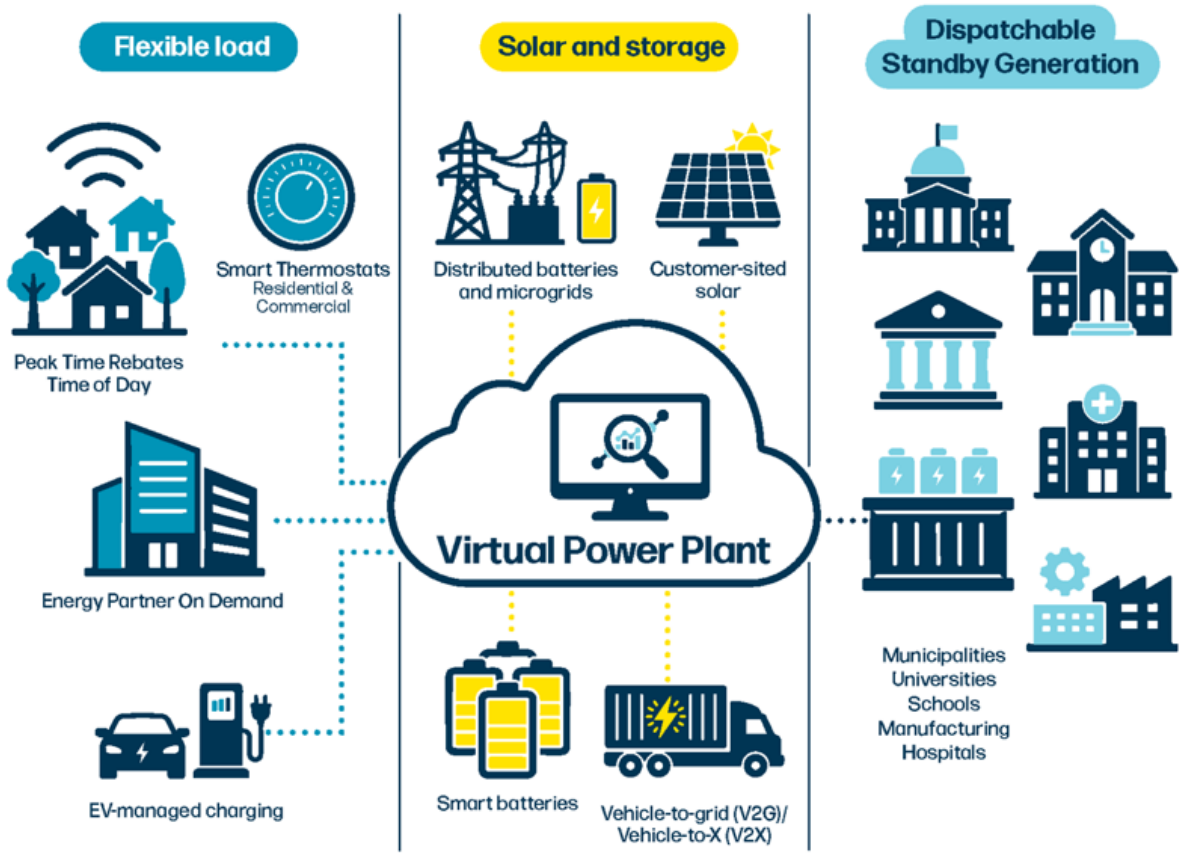
1.2.4 Virtual Power Plant

PGE's Virtual Power Plant (VPP) is a grid-integrated resource that coordinates more than 600 MW of capacity from over 250,000 enrolled customers across a portfolio of programs for all customers. This is approximately four times the national average participation rate. The VPP includes some of PGE's most cost-effective customer-side resource opportunities, particularly where flexible load and distributed resources can leverage existing system and customer-owned assets to provide energy, capacity and other grid services. By increasing the value of resources already connected to the system, the VPP can complement new generation, transmission, and distribution investments and, where appropriate, help avoid or defer higher-cost infrastructure.

The VPP provides PGE with another resource option for meeting customer and system needs. Participating customers receive value for the flexibility they choose to provide, while all customers can benefit when VPP resources reduce exposure to higher-cost energy periods, support reliability, improve utilization of existing infrastructure, or help address local grid needs. The VPP complements, but does not replace, the generation, transmission, and distribution investments necessary to serve growing customer demand.

[15] By the U.S. Department of Energy's National Laboratory of the Rockies (NLR), formerly known as National Renewable Energy Laboratory (NREL). NLR did not release rankings in 2011.

Figure 15. VPP at a Glance



PGE coordinates a portfolio that includes flexible loads, managed charging, customer-sited storage and eligible customer generation. Depending on the resource, PGE may directly dispatch equipment, send customer or aggregator event signals, shape load through rates, or incorporate distributed generation into net-load forecasting and operating decisions. PGE serves as the portfolio orchestrator and is responsible for forecasting, operating, measuring and managing portfolio performance. From 2015 to 2025, PGE's Flexible Load programs experienced a 100X growth rate, as enrollment increased from 2,300 customers to more than 250,000 customers. Program enrollment is more than a marketing function—it is critical to PGE's ability to meet the VPP targets supporting customer energy needs.

The VPP is a proven, reliable, scalable resource on a sustainable growth trajectory.[16] Across its portfolio, PGE conducts more than 500 resource and program dispatches annually for energy shifting, peak management, reliability and other grid needs. During the July 21, 2026 heat event, PGE coordinated seven VPP programs in staggered waves and reduced system load by approximately 128 MW at the key peak hour—roughly equivalent to the electricity demand of

[16] The U.S. Department of Energy cites PGE's VPP as a national reference case. U.S. Department of Energy. (2023, September). Pathways to commercial liftoff: Virtual power plants. https://climateprogramportal.org/wp-content/uploads/2025/06/LIFTOFF_DOE_VPP_2023.pdf

120,000 homes. When they reduce the cost of serving peak demand, VPP resources can provide benefits to all customers, both those who participate and those who do not. By reducing or shifting load during higher-cost periods, VPP resources can reduce reliance on more expensive market purchases or supply-side resources and can improve the utilization of existing infrastructure. To the extent these avoided costs are realized and reflected in the portfolio benefit-cost analysis, they support affordability for the broader customer base.

The large load customers connecting in PGE's service area today are bringing resources that can be integrated with PGE's VPP. They are bringing flexibility and broader system benefits that add value for all customers who receive energy from PGE. When including 400 MW of large customer flexible load as forecasted by PGE's Flexible Load Interconnection Analysis (in addition to participating DSG), IRP forecasts the VPP portfolio to have a total capacity equal to approximately 25% of peak capacity need by 2030.

PGE customer demand is growing and changing shape, more energy resources are being installed behind the meter at customer locations, and regional markets are changing how utilities plan and operate their systems. At the same time, affordability and reliability remain crucial customer priorities.

These changes increase the need for reliable resources that can respond when and where energy is needed. PGE's VPP provides an important part of that solution by making existing customer and distributed resources more useful to the grid. It does not eliminate the need for new generation, transmission, or distribution infrastructure. Instead, it provides another resource option that can help PGE better use existing infrastructure, manage new load, and make the right investments at the right time.

PGE's VPP consists of a diverse portfolio of existing or future customer-owned DER measures which include smart thermostats, electric vehicle chargers, electric water heaters, battery storage systems, backup generators, agricultural loads, and behind-the-meter solar. For the purposes of the IRP modeling and analysis, these resources have been broadly categorized into four high-level groups: flex load programs and pilots, potential DER measures in the future, customer-sited solar, and dispatchable standby generation. See Section 7.10 for additional information on VPP results.

1.2.5 Customer Affordability Priority

Affordability is a fundamental priority in every stage of the clean energy transition. As PGE invests to support growth and decarbonization, the Company is focused on delivering those investments on a least-cost, least-risk basis while maximizing the value of infrastructure customers have already funded.

PGE has pursued several strategies to manage costs. Since 2001, the Company has secured more than $1.4 billion in federal tax credits associated with Company-owned clean energy investments and estimates that an additional $1.7 billion in federal incentives may be realized through long-term third-party energy contracts. PGE continues to incorporate available incentives into procurement decisions while retaining flexibility as federal policy and market conditions evolve.

PGE is also using technology and customer flexibility to increase the capability of the existing system and defer or avoid higher-cost infrastructure where practical. GETs, including advanced

conductors, sensors, and dynamic line ratings, are increasing transmission capacity by as much as 20% under the right conditions. In 2025, a project with GridCARE developed flexible load interconnection analyses to unlock more than 80 MW of additional system capacity as part of a broader portfolio, expected to provide more than 400 MW by 2029.

PGE's VPP similarly leverages customer resources to support reliability, manage peak demand, and improve utilization of existing infrastructure. PGE is working on a non-wires alternative, or non-wires solution, which is intended to defer the need for traditional upgrades (like upgrading a distribution feeder) by using VPP Flexible Load resources. Rather than procuring new utility-owned assets or specialized equipment, the effort seeks to maximize the value of participating customer-sited flexible load resources by increasing targeted enrollment and dispatch capability in areas where feeder-level load relief may support infrastructure deferral.

PGE has also worked with regulators and policy makers to better allocate costs on the system. In 2026, PGE implemented the POWER Act, introducing a new tariff structure that allocates growth-related costs to large-load customers through a Peak Growth Modifier and related mechanisms. Under this new framework, datacenters contribute to investments needed to serve them, while an expanded customer base for system cost recovery results in lower bills for residential customers. Through this approach, PGE can support continued growth while maintaining a strong focus on affordability.

Together, disciplined procurement, federal incentives, infrastructure optimization, customer participation, and fair cost allocation demonstrate that affordability is not separate from PGE's clean energy strategy. It is fundamental to how PGE executes it. These principles will continue to guide implementation of the Clean Energy Plan and Integrated Resource Plan.

1.2.6 Advancing Regional Integration and Resource Adequacy

PGE continues to advance regional solutions that maintain reliability, improve affordability, and expand access to diverse energy and capacity resources. As Western markets and resource adequacy frameworks evolve, PGE's strategy emphasizes flexibility—participating in regional constructs where they provide demonstrable customer value while preserving the ability to pursue alternative solutions that better meet PGE's reliability and operational needs.

This approach is reflected in PGE's decision not to participate in the Western Resource Adequacy Program (WRAP) while evaluating alternative approaches to meeting its long-term resource adequacy needs. During this transition, PGE will continue to maintain adequate resources to reliably serve its customers and pursue regional coordination that provides access to diverse capacity and recognizes the increasingly interconnected nature of the Western grid. PGE is working with other EDAM-committed utilities, regulators, and stakeholders to develop a resource adequacy solution that leverages the transmission connectivity and resource diversity present in EDAM-committed utilities.

A durable regional framework must also establish comparable resource adequacy obligations across load-serving entities. Until such a framework is established, PGE supports clear and consistent standards for all utilities serving Oregon customers.

PGE is pursuing this strategy alongside implementation of the Extended Day-Ahead Market (EDAM), strategic hydro and dispatchable capacity contracts, and transmission investments that expand access to regional resources. Together, these efforts provide a flexible portfolio of tools to manage reliability and affordability while allowing PGE to adapt as regional markets and resource adequacy frameworks continue to develop.

1.2.7 Improving Clean Energy Planning Accessibility

Throughout the 2026 CEP/IRP planning cycle, PGE's outreach and engagement activities created opportunities for community members and the Community Benefits and Impacts Advisory Group (CBIAG), a community advisory group required by HB 2021 that represents environmental justice communities and low-income rate payers, to learn about the planning process and provide input. PGE designed its engagement approach to support broader public awareness while offering accessible and meaningful opportunities for participation throughout the development of the 2026 CEP/IRP.

In March 2025, PGE filed its inaugural Community Engagement Strategy in response to expectations outlined by the Commission in Order No. 24-096.[17] The engagement approach used for this CEP/IRP cycle was informed by that strategy.[18] At the beginning of the IRP development process, PGE evaluated its existing engagement practices, held conversations with interested parties and reviewed feedback submitted through regulatory dockets. This strategy was intended to strengthen how PGE shares information, gathers input, and creates opportunities for participation in long-term planning discussions, while creating opportunities for meaningful engagement.

The Community Engagement Appendix C describes the engagement activities completed throughout the development of the 2026 CEP/IRP in greater detail. Key themes and takeaways from those efforts are summarized below. Activities included CBIAG discussions on the CEP/IRP and Community Benefit Indicators (CBIs) in planning, PGE's All-Source Request for Proposals (RFP), and workforce and labor strategy. PGE also conducted community outreach and engagement at the Community Services Network (CSN) East County Resiliency Fair, the Community Energy Project Resource Fair, the Portland CSN Community Resiliency Fair, and the Center 50+ Energy and Resource Fair in Salem.

These activities provided multiple opportunities to introduce planning concepts, answer questions, and gather community perspectives. At community events, PGE collected feedback from interested participants through a brief anonymous survey and plans to continue gathering community input through similar survey efforts at future engagement events.

Table 1 summarizes these activities organized in a consistent framework: what we did, what we heard and what we learned through the engagement process. This structure is intended to document key themes, questions, and areas of interest. See Appendix Section C.1 for more detail.

[17] See https://edocs.puc.state.or.us/efdocs/HAD/lc80had335791056.pdf
[18] LC 80 Order No. 24-096, Staff Recommendation #6. https://apps.puc.state.or.us/orders/2024ords/24-096.pdf.

Table 1. 2026 Planning Cycle Community Engagement Summary

Engagement Activity	What We Did	What We Heard	What We Learned
CBIAG: CEP/IRP Intro **January 28, 2026**	Key elements of the IRP and who is involved. Considerations for planning, such as assumptions, tradeoffs, evolving information.	Active engagement from every member; 24 questions and comments. Interest in building technical understanding while grounding in real-world affordability, reliability, customer impacts.	Affordability was the primary concern, with foundational knowledge of technical concepts strengthening participation and confidence.
East County Resiliency Fair **February 21, 2026**	Workshop on core concepts in long-term planning for public audience.	Some participation; questions and concerns focused on customer bill impacts and affordability.	Long-term planning specifics and modeling were not of interest to this public audience, but real-world cost concerns were.
PGE Long-Term Planning Booth **February 21, 2026**	Info tables included planning, Income-Qualified Bill Discount (IQBD), transportation electrification, workforce, preparedness.	~100 visitors; questions and concerns focused on energy costs and monthly bills. 32 attendees participated in anonymous and voluntary long-term resource planning short survey.	Affordability was the most common theme across survey responses, with clean energy and reliability also priorities of interest.
CBIAG: All Source RFP **February 25, 2026**	Key elements of procurement processes and who is involved.	Some participation; seven (7) questions and comments. Strong interest in connection between RFPs and community benefits.	Building familiarity with how utilities procure new resources was of interest, but opportunity to further refine level of detail for the audience.
CBIAG: CBIs **April 22, 2026**	Reintroduction of CBIs and the evolving framework within planning.	Active engagement; 14 questions and comments. Affordability is central to community priorities. Interest in how CBIs are shaped and applied.	The complexity of this topic, how to balance priorities, and the difficulties of putting metrics here for planning purposes were understood. High interest in this topic and how to participate endures.
East Portland Community Resiliency Fair **May 30, 2026**	Info tables, including long term resource planning, customer service rep, Income-Qualified Bill Discount (IQBD), transportation electrification ride and drive, wildfire preparedness.	Attendees were engaged in discussions about EV adoption, grid modernization and long-term resource planning.	Survey findings continued to show affordability as the dominant concern, while participants also prioritized reliability, grid resilience, and clean energy in future planning.

Engagement Activity	What We Did	What We Heard	What We Learned
Center 50+ Energy & Resource Fair (Salem) **June 27, 2026**	Facilitated the "How PGE Plans for the Future" workshop and engaged with participants. Hosted a resource planning booth featuring customer programs (IQBD & Demand Response), grid education and future energy priorities.	Participants were highly engaged, asking questions and expressing appreciation for PGE bringing long-term resource planning education into a community setting.	Survey results reinforced affordability as the highest priority, while reliability, resilience, community benefits, and clean energy remained important considerations for future resource planning.

Across all engagement approaches, clear and consistent themes emerged. Participants were primarily focused on the outcomes of long-term planning, particularly customer bill impacts, affordability, reliability and access to customer programs, rather than the technical details, methodologies, or planning processes used to develop long-term planning. Broadly, participants were interested in understanding how the company makes real-world decisions and investments over understanding specific details of data assumptions, modeling, or long-term planning. These perspectives have informed PGE's planning as expressed through this CEP, including underscoring the importance of prioritizing customer affordability (Section 1.4.1), the foundational role of customer- and community-sited resources in PGE's portfolio (Section 1.2.3 and Section 1.2.4), and PGE's ongoing efforts to use Community Benefit Indicators to track the impacts of utility planning decisions on key areas of importance to communities (Section 1.4.2).

Together, these outreach approaches expanded awareness of the CEP and IRP while elevating community perspectives on how long-term planning relates (or does not) to customer experience and cost. These activities provided a foundation for ongoing engagement, especially with the CBIAG. The questions and perspectives shared will continue to inform how PGE approaches transparency and participation, including the ongoing need to ensure that complex technical topics are communicated in ways that remain relevant, accessible, and meaningful. PGE also learned the importance of continuing to find ways to bring interested parties along on topics and in forums where their interests and concerns are most readily addressed, which may not be in IRP and long-term planning.

1.3 Moving Forward towards 2030 and Beyond

The clean energy planning environment has evolved considerably since 2021, as discussed in detail in Chapter 3. PGE has performed rigorous analysis of projected energy demand, customer-sited and utility-scale resource capabilities, regional trends, and cost ranges. This analysis provides PGE's most detailed understanding to date of what it would take to meet HB 2021's 80% emissions target as well as alternative pathways forward. The modeling methods, input assumptions, and draft results have been shared over the past 18 months through over 30 hours of workshops supported by detailed materials posted on PGE's public website.

HB 2021 determines that a Clean Energy Plan must result in an affordable, reliable and clean electric system[19]. PGE remains committed to reducing emissions on the system and providing customers with increasingly clean energy - but the headwinds facing this decarbonization journey cannot be ignored. Even if the barriers related to increased competition for resources, transmission constraints, and all other execution related challenges were resolved, actions taken to achieve the HB 2021 Preferred Portfolio would likely surpass the statutory affordability threshold of six percent of annual revenue requirement. PGE utilized this affordability threshold, embedded within HB 2021, to inform a path forward that balances emissions progress with affordability.

1.3.1 External Landscape

The electric utility sector is experiencing a period of rapid change as described in detail in Chapter 3. Customer demand is increasing, peak needs are becoming more pronounced, and the market, policy, and infrastructure environment continues to evolve. Since PGE's 2023 CEP/IRP, the planning landscape has become more complex due to load growth, changing federal policy, increased resource costs, transmission constraints, and tighter regional resource adequacy conditions.

PGE also faces additional procurement challenges related to unresolved exposure to wildfire risk and restricted financing options, further discussed in Section 3.5.1 and Section 3.5.2. PGE's Action Plan requires procurement of multiple gigawatts of new clean resources. The capital investments necessary to support these projects will be significant, wildfire risk and restrained financing flexibility continues to increase capital costs, which drives up the cost of these clean energy projects for customers.

These conditions affect the pace and sequencing of actions needed to maintain reliability, manage affordability, and continue clean energy progress. Across the West, utilities are planning for growing demand while also facing longer development timelines for new generation and transmission, increased competition for viable projects, and greater reliance on resources whose contribution to reliability varies by season, weather, location, and duration. Regional assessments have identified increasing resource adequacy risks in the Northwest and broader Western Interconnection, including risks associated with load growth, transmission constraints, project development uncertainty, and extreme weather conditions.

PGE's planning must account for these realities without losing focus on the long-term direction of the clean energy transition. HB 2021 was adopted in a period when demand, renewable resource costs, and technology development appeared to support a more predictable path toward emissions reductions. Five years later, PGE continues to pursue that direction but must do so in a planning environment where customer needs are higher, resources are costlier and less certain, transmission is more constrained, and regional reliability conditions require greater attention.

[19] https://olis.oregonlegislature.gov/liz/2021r1/Downloads/MeasureDocument/HB 2021/Enrolled.

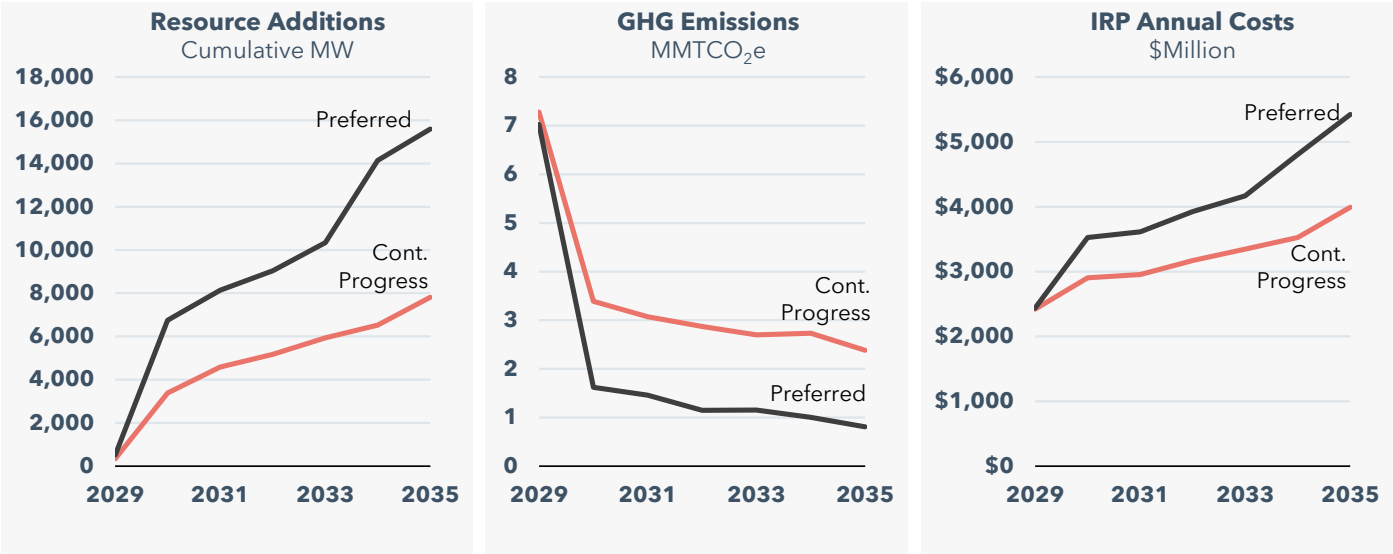
1.3.2 Evaluation of Planning Pathways

As described in IRP Chapters 4 to 7, PGE's planning analysis included construction of hundreds of 20-year resource portfolios associated with 24 planning scenarios. Scenarios and portfolios incorporated plausible outcomes for dozens of variables such as load forecasts, generation resource availability, tax credit policy, and regional transmission options with incorporation of feedback from stakeholders. Portfolios were assessed across 37 price futures, informing assessments of customer costs, risks, and retail emissions across each portfolio.

This robust analysis highlights the trade-offs associated with resource planning decisions and the resulting impacts on affordability and reliability. The HB 2021 Preferred Portfolio is required by rules to achieve the established emissions reductions targets outlined in HB 2021[20]. The HB 2021 Preferred Portfolio identified in this analysis described in detail in Chapter 7, is the lowest cost option to meet the 2030 HB 2021 emissions target, while ensuring reliability—this portfolio requires PGE to bring 6,747 MW of solar, wind and storage resources online by the end of 2029, while maximizing available on-system resources, with 2,300 MW of additional resources deployed through 2032.

The HB 2021 Preferred Portfolio's pace of resource additions presents major challenges, both in terms of achievability, regional transmission infrastructure, and customer price impacts. Hence the IRP also includes a Continued Progress Portfolio, which offers a balanced alternative to continual emissions reduction progress at reduced costs. Comparison of the two (2) portfolios informs PGE's action plan.

Figure 16. Comparisons of HB 2021 Preferred Portfolio and Continued Progress Portfolio



[20] https://secure.sos.state.or.us/oard/displayDivisionRules.action;JSESSIONID_OARD=fLm7IkWry5cy9H_KTM2CqxMZcfyXF2XmQ9UQqA3DrFHi5O6Kg9GC!-387146672?selectedDivision=5058

1.3.3 Opportunities Identified Across Portfolios

Comparison of the HB 2021 Preferred and Continual Progress portfolios demonstrate many areas of alignment. While acquisition volumes differ, both portfolios emphasize the importance of continued clean energy resource acquisition and VPP scale-up, with continued reliance on development of non-emitting resources to meet future needs. Additional key takeaways include:

- **Transmission expansion is foundational to reliability, affordability, and decarbonization.** Transmission connects customers to the diverse energy and capacity resources needed to reliably serve growing demand while managing costs and reducing emissions. PGE's strategy begins with maximizing the existing infrastructure capability that customers have already funded through GETs (e.g., dynamic line ratings, advanced conductors) and other operational innovations, including utilizing artificial intelligence to increase capacity and defer more costly investments. At the same time, PGE's portfolio analysis demonstrates that optimizing the existing system alone will not be sufficient. Additional regional transmission will be necessary to access new resources, strengthen resource adequacy, increase geographic diversity, and preserve flexibility as regional supply and demand conditions evolve. PGE is therefore pursuing a portfolio approach that combines optimization of existing infrastructure with strategic expansion of regional transmission capability. PGE's transmission analysis and conclusions are discussed in Chapter 7.
- **Large-load growth can bring significant new investment to Oregon while expanding the customer base supporting investments in generation and grid infrastructure.** Consistent with the principle that growth pays for growth, PGE's large-load framework is designed so that customers driving significant incremental demand bear the associated costs and risks, protecting existing cost-of-service customers from inappropriate cost shifting. When large-load growth materializes, it provides support for broader system investments and can improve system utilization. Since many large load customers develop their own on-site energy systems, such as large-scale battery systems that integrate directly into PGE's grid, their growth can also help meet peak needs for all customers. At the same time, uncertainty regarding the precise locations and timing of load additions necessitates planning approaches that maintain flexibility as conditions evolve. This balanced approach allows PGE to serve customer growth and respond to changing load expectations while maintaining affordability, reliability, and continued investment in an increasingly clean energy system.
- **Existing gas generation provides essential reliability as the system transitions.** PGE's existing fossil fuel fleet provides firm, dispatchable capacity that remains important to maintaining reliability as increasing quantities of renewable energy are added to the system. Wind, solar, and battery storage provide significant energy and capacity value, but current commercially available storage technologies do not yet economically address all periods of prolonged low renewable production or extreme weather events. PGE's portfolio analysis reinforces an important distinction between energy production and reliability value. Under both the HB 2021 Preferred Portfolio and Continued Progress portfolios, annual generation from PGE's gas fleet serving retail customers can decline significantly while the fleet

continues to provide critical capacity during relatively infrequent but consequential periods of system stress. Maintaining this existing capability provides a reliability backstop, supports integration of additional variable renewable resources, and reduces the need to prematurely replace dependable capacity with potentially higher-cost alternatives. PGE's strategy therefore anticipates a changing role for its existing gas fleet: lower utilization over time as clean energy additions increase, while preserving firm capacity until reliable and cost-effective alternatives are available at sufficient scale. This approach enables continued emissions reductions while maintaining the reliability and affordability customers depend on.

- **Regional hydropower provides significant reliability, affordability, and decarbonization value, but availability is increasingly constrained.** Long-term access to regional hydropower provides a unique combination of non-emitting energy, dependable capacity, and operational flexibility that complements wind, solar, storage, and customer resources. However, significant regional load growth, tightening resource adequacy conditions, and increasing competition for existing clean resources are reducing the amount of hydropower available for new or renewed long-term commitments. When hydro is available on cost-competitive terms, securing long-term access can diversify PGE's portfolio, reduce exposure to volatile short-term markets, strengthen reliability during periods of high demand or lower renewable production, and support continued emissions reductions.
- **Long-term portfolios continue to rely on emerging generation technologies.** PGE faces significant challenges in achieving the established emissions targets reliably and affordably. This requires systematically replacing fossil fuel generation and purchases with non-emitting energy and capacity resources. Zero-emissions technologies available today primarily include costly variable energy resources (VERs), such as wind and solar, as well as short duration (mainly 4-hour) battery storage. Deep decarbonization using these existing technologies alone puts at risk the reliability of the entire PGE system.[21] These technologies are not dispatchable (there when you need them) and there are limitations to the energy they can provide, especially during sustained heat or cold events. To contemplate moving beyond natural gas in the long-term, continued attention is needed on the development of commercially viable alternatives.
- **Current Small-Scale Renewable (SSR) eligibility requirements may increase costs without advancing broader clean energy objectives. HB 2021 raised Oregon's SSR requirement to 10% of PGE's generation portfolio capacity.** PGE has expanded customer-sited solar, storage, and VPP– capabilities that provide clean energy, flexibility, resilience, and system benefits; however, under current OPUC criteria these resources

[21] E3, Resource Adequacy and the Energy Transition in the Pacific Northwest, 2026, https://www.ethree.com/ra-pnw/.
GridLab and Sylvan Energy Analytics, Near-term winter resource adequacy challenges in the Pacific Northwest, 2026, https://gridlab.org/portfolio-item/pnw_nearterm_winterra/.
NERC, 2026 State of Reliability report, 2026, https://www.nerc.com/newsroom/2026-State-of-Reliability-Report.
NWPCC, Pacific Northwest Power Supply Adequacy Assessment for 2029, 2024, https://www.nwcouncil.org/fs/18853/2024-4.pdf.
ODOE, Oregon Energy Strategy, 2025, https://www.oregon.gov/energy/data-and-reports/Documents/Oregon-Energy-Strategy.pdf.
PNUCC, Northwest Regional Forecast, 2026, https://www.pnucc.org/wp-content/uploads/2026-PNUCC-Northwest-Regional-Forecast-4-21-26-final.pdf.

generally do not qualify toward the SSR requirement.[22] PGE continues to pursue qualifying resources through the Community Solar Program and cost-effective community-based renewable energy projects that provide identifiable customer and community benefits. However, to the extent additional SSR compliance requires acquiring resources based primarily on the need to comply with HB 2021, rather than demonstrated system need or customer value, PGE's modeling indicates increasing compliance costs as the broader portfolio becomes cleaner, including under the HB 2021 Preferred Portfolio. Excluding customer-sited resources from SSR eligibility hinders PGE's ability to prioritize the desires of communities and stakeholders, who actively seek increased support for these types of resources. Greater flexibility in SSR compliance could better align statutory requirements with affordability, decarbonization, resilience, and community benefits. See Section 7.8 for further analysis.

1.4 Informed Decisions on Behalf of PGE's Customers and Communities

House Bill 2021 sets ambitious emissions reduction targets for PGE, with demonstrations of progress required along the way.[23] HB 2021 also requires PGE to meaningfully include equity, resilience, and community-based renewable energy (CBRE) resources as part of its decarbonization efforts, and to evolve the resource planning approach to include a broader range of community benefits. The inclusion of community benefits marks a change in how utilities like PGE evaluate resources and other system investments to serve customers. PGE has evolved its approach over the past five years through the combined CEP/IRP processes to identify community benefits indicators and adapt IRP methods and public and stakeholder engagement approaches to begin to account for them.

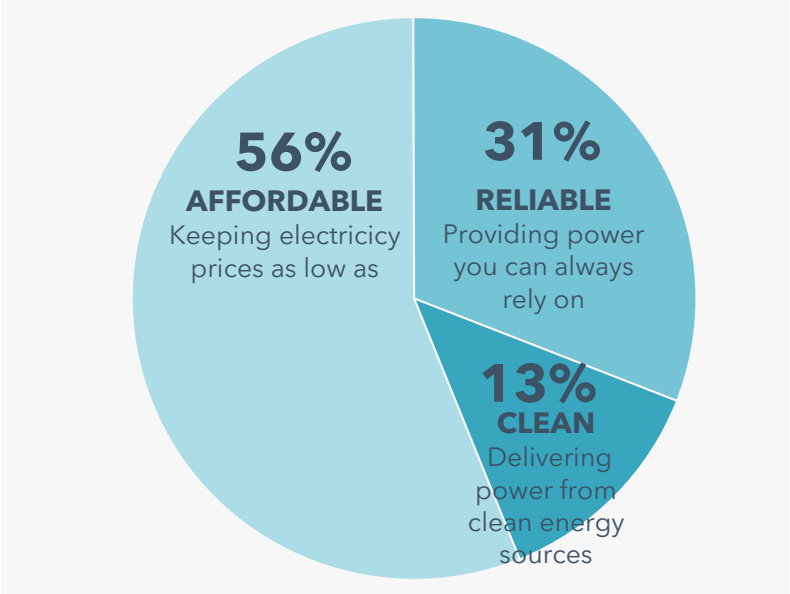
PGE believes this 2026 CEP/IRP is the best representation so far of realistic planning toward a cleaner energy future. Modeling advancements were made and assumptions refined to as closely reflect known realities at this time as is reasonable in analysis, and enhanced community outreach compared to previous planning processes.

1.4.1 Prioritizing Affordability in Planning Decisions

Energy affordability is a priority for PGE customers and communities. It is the most frequently cited concern in public and community input on PGE's planning processes and in conversations with communities across the Company's service territory. PGE's actions, summarized in Section 1.2.5, include pursuing available tax credits to reduce the cost of clean energy investments, using competitive procurement processes to identify least-cost, least-risk resource options, and allocating growth-related costs appropriately to the customer classes that drive those investments, all with the objective of supporting customer affordability.

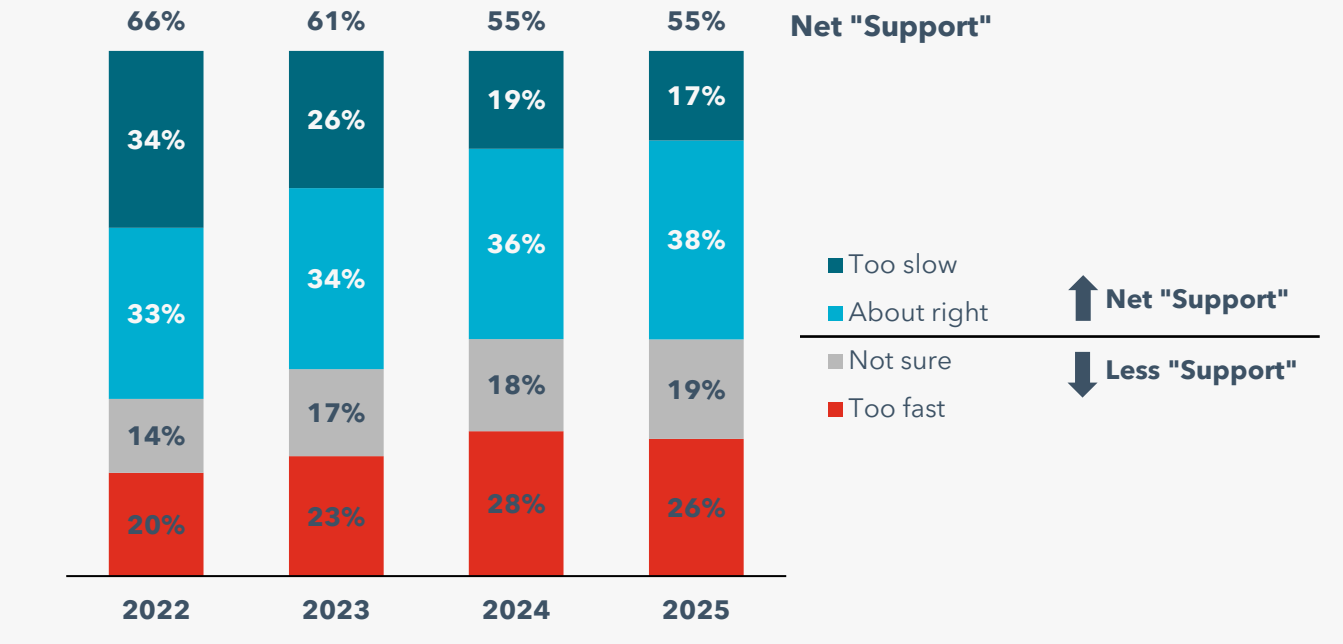
[22] OAR Chapter 860, Division 91.
[23] ORS 469A.405.

Figure 17. Priorities Based on Residential Customer Survey



As shown in Figure 17, when seeking to understand where PGE can best focus efforts to provide electric service in ways that are most important to residential customers, recent survey responses overwhelmingly indicate the priority is affordability, followed by reliability. Clean energy is viewed as the lowest priority to customers when compared directly to cost and reliable power.

Figure 18. Customer Support Trends for Clean Energy Transition



When asked "Do you think the State of Oregon's goal of achieving 80% cleaner electricity by 2030 and moving to 100% clean electricity sources by 2040 is too fast, too slow, or about right?", the

trend shown in Figure 18 indicates movement toward an even split between more and less supportive. Growing responses of the pace being "too fast" in the past couple of years correlate with rate increases and maintained focus on affordability as main priority (as shown in Figure 17).

The above survey results act as important signposts that inform PGE's CEP/IRP scenario development and Action Plan prioritization. This data and further learnings across community engagements[24] suggests that customers are focused on affordability and seem to have growing concerns regarding the pace of the clean energy transition. PGE's evaluation of multiple planning pathways to develop the Action Plan centers affordability in PGE's approach, recognizing that meeting rising demand with affordable, reliable, and increasingly clean energy requires grid modernization, growth, and diversification of generation and new transmission and distribution infrastructure. As described above, the approach to meeting all these needs includes both specific and intentional planned actions, as well as space to listen, learn, and evolve next steps based on customer needs and emerging information.

1.4.2 Community Benefits of PGE's Actions

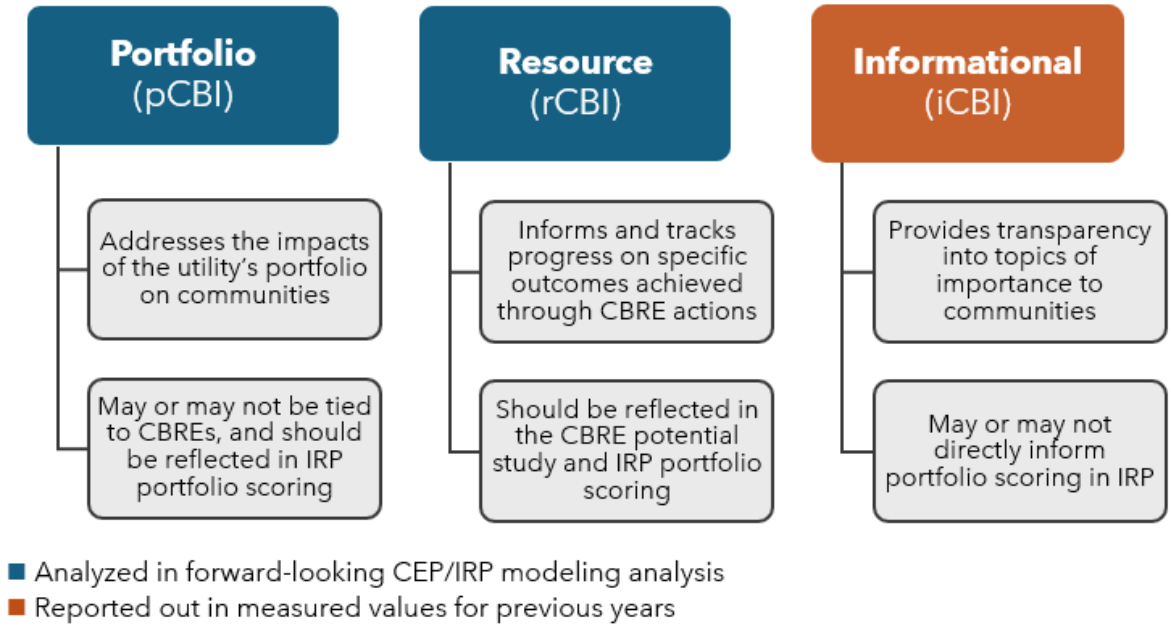
HB 2021 emphasizes that deployment of clean energy must, to the extent practicable, be advanced to provide additional direct benefits to Oregon communities.[25] PGE's advancement of clean energy and grid enhancement have benefited Oregon communities in numerous ways, above all through the enablement of daily life through provision of affordable, reliable electricity. In addition, clean energy projects provide direct and quantifiable benefits for Oregonians in the areas of family-wage jobs, increased tax and community development revenues for local governments, and reduction of greenhouse gas emissions.

Further, as a result of HB 2021, PGE now uses community benefit indicators (CBIs) to track progress and inform IRP analysis. These indicators have been significantly advanced since the 2023 CEP/IRP, though continuing work is needed. See Appendix D for robust review of CBI work to date and analysis included in this CEP/IRP, as informed by stakeholder engagement, the CBIAG, communities, and new CEP/IRP regulatory requirements. The appendix also includes measured values for community benefits indicators for each of the previous three (3) years.

Broadly, CBIs are addressed in planning in three (3) structured pathways, as summarized in Figure 19. A fourth use case of CBIs—screening real project or program proposals—falls largely beyond the scope of planning and the CEP/IRP. PGE's efforts to develop CBIs via a planning framework may inform but is not intended to limit community benefits that PGE may seek to advance via specific projects or programs, for example individual CBRE deployment or customer programs.

[24] See Appendix C Community Engagement–2026 Clean Energy Plan and Integrated Resource Plan and Community Benefits Indicators.
[25] ORS 469a.405(2).

Figure 19. PGE's Approach to CBIs in Planning



Considering the principles outlined in HB 2021, PGE has continued 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.[26] In the range of efforts to advance this work, PGE continues to face several challenges integrating CBIs into IRP processes. Key challenges include data gaps, proxy metric limitations, and diverse stakeholder priorities, highlighting the need for continued research, collaboration, and refinement. While methodologies continue to evolve, CBI analysis remains distinct from other scoring metrics and provides valuable information for utility decision-making. As described in Appendix D, CBI analysis, in and out of planning contexts, has informed investment decisions, contract negotiations, program design, and RFO and RFP requirements.[27]

1.4.3 Prioritizing Resilience in Resource Actions

Among the community benefits summarized in the previous section, resilience is a key objective associated with the clean energy transition. Resilience has broad applicability across utility planning, operations, and customer service, and it intersects with PGE's CEP in a number of ways. PGE defines resilience as the ability to anticipate, adapt to, withstand and recover from disruptive events. Broadly, PGE's focus on addressing critical risks to generation, transmission and distribution systems while coordinating efforts across business functions to support resilience across PGE's system and the communities it serves.

[26] Oregon House Bill 2021, Section 1(3)(a), 2021 Regular Session, https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB 2021/Enrolled.
[27] OAR 860-90-0060(7)(g)(E) and OAR 860-90-0100(4).mi

PGE's efforts related to clean energy and resilience include developing connected neighborhood microgrids, deploying smart community initiatives and updating design standards to address extreme weather conditions. Investments in wildfire mitigation, such as vegetation management practices, situational awareness tools, and system hardening, also contribute to grid resilience and public safety. PGE continues to expand existing programs that support community resilience, including the Dispatchable Standby Generation (DSG) program, which supports 50+ microgrid-capable sites, including hospitals, government buildings and educational institutions. Also, PGE offers programs for customers including the Medical Certificate Program and Medical Battery Program for qualifying customers located in high fire risk zones. The Medical Battery Program provides a portable backup battery to eligible customers who rely on electricity-powered medical devices. Between 2023 and 2025, the program served 152 eligible customers and transitioned from a pilot to an ongoing program, supporting customer outage preparedness and resilience.

PGE's progress in identifying and addressing risks, as well as actions related to system resilience, are described in detail through the following strategies:

- The Wildfire Mitigation Plan (WMP) guides annual investments in system hardening, vegetation management and operational measures such as Public Safety Power Shutoffs (PSPS). During 2025, PGE invested approximately $56 million in wildfire mitigation capital projects, including system hardening, inspection and correction activities and situational awareness investments. These initiatives are intended to reduce ignition risks, support grid resilience, and reduce customer impacts during wildfire events.
- The Distribution System Plan (DSP)[28] describes PGE's processes for identifying and prioritizing infrastructure upgrades and grid modernization initiatives. As discussed in PGE's most recent Distribution System Plan, grid needs are identified through a comprehensive assessment of system loading, reliability performance, asset risk, forecasted load growth, DER adoption, and other planning drivers. Identified constraints are evaluated and prioritized using a structured ranking framework that considers safety, customer commitments, reliability, compliance requirements, risk reduction, equity, and system performance. The resulting prioritized grid needs inform the development and selection of infrastructure investments and non-wires solutions that support a safe, reliable, and affordable distribution system.

PGE's clean energy planning includes exploring opportunities to increase community resilience through the evaluation of resource CBIs. While maintaining a reliable system across a range of climate and load conditions is a core planning objective, more direct community resilience benefits are closely associated with PGE's CBRE proxy resource, discussed in the next section. PGE's analysis indicates that CBREs, based on bid costs from the CBRE RFO, have higher costs than alternative non-emitting resource options and would increase customer costs relative to those alternatives. Some CBREs may be capable of maintaining partial or full electric service to one or multiple customers during local grid outages. The costs associated with resilience benefits are typically paid by the residential or business customers receiving them. Additional opportunities to support

28 https://downloads.ctfassets.net/416ywc1laqmd/6fsVybjYRmGNV4M7PwBOI2/c9ffcaa9e432ea82d67e6359c24c76ac/2024_PGE_DSP_2024_12_18.pdf

resilience for vulnerable customers, critical infrastructure and community-serving facilities may be available through programs or other funding mechanisms outside of resource planning processes. These efforts may also align with non-utility programs, incentives and grant funding that can supplement utility investments.

The value of resilience may differ across customers, communities and geographic locations. PGE supports continued efforts to improve understanding and quantification of resilience-related value drivers. PGE identifies opportunities where the estimated value to customers, communities, program administrators, or funding entities exceeds the incremental cost, as reflected in the rCBI framework described in Chapter 7. Identifying and advancing projects through programs, resource acquisition activities and collaboration with funding partners is identified as a near-term action in Chapter 2.

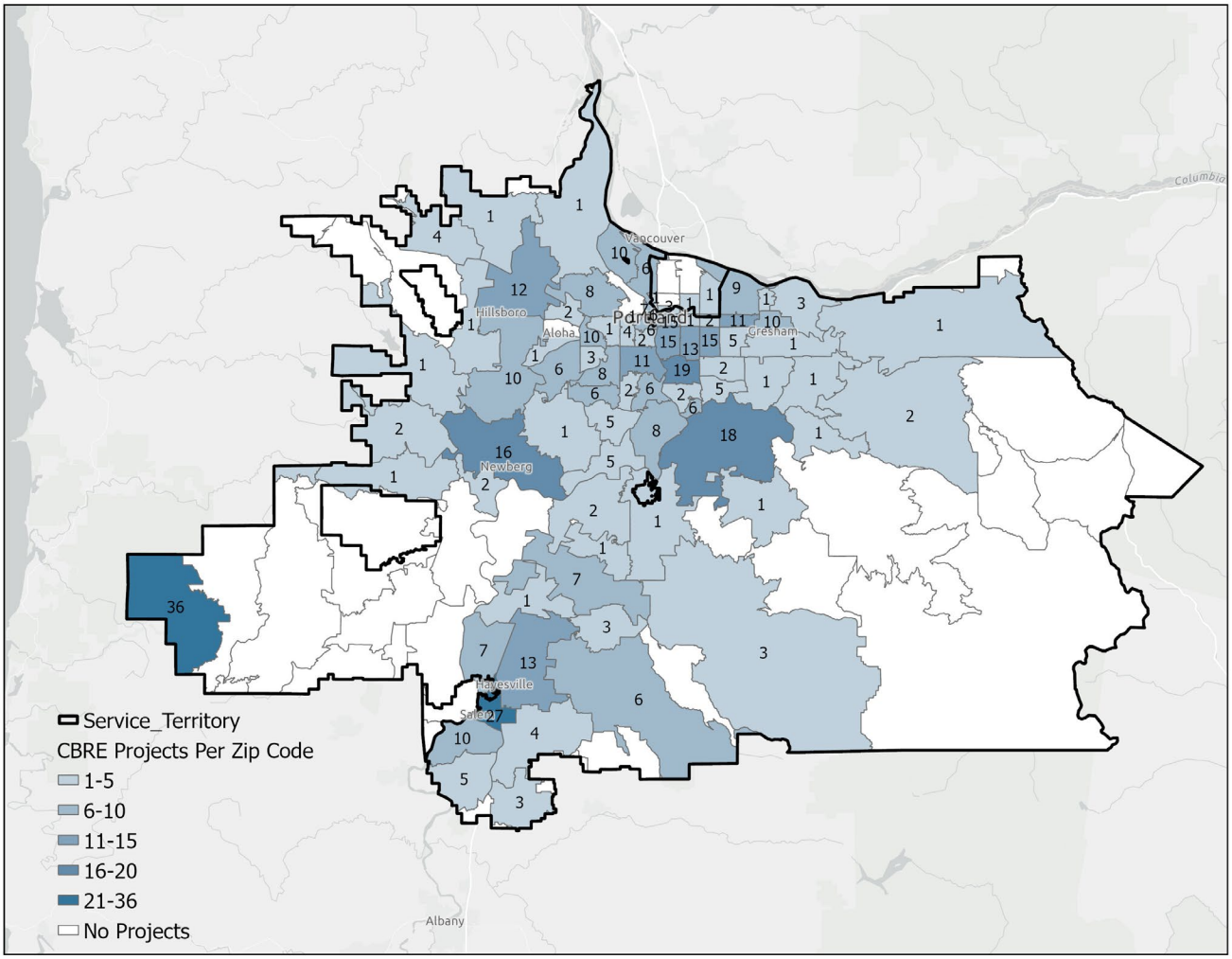
PGE's 2026 CEP incorporates resilience through reporting on resilience-related informational CBIs and through the development of an rCBI metric within the planning framework that may inform future clean energy and community-focused program design and implementation (see Section 7.9 and Appendix D for additional detail). PGE may also acquire resources that provide resilience-related co-benefits where incremental costs, as estimated through the rCBI framework, are paid by participating customers or offset through non-utility funding sources.

1.4.4 Assessing Opportunities for Community-based renewable energy

Utility system investments, especially clean energy projects, create economic, environmental, and reliability benefits for customers and communities. Driven by HB 2021's requirements and PGE's commitments and activities through the Oregon Clean Energy Workforce Coalition, PGE's clean energy acquisition actions require strong labor standards with PGE requirements including a minimum of prevailing wage, apprenticeship utilization, and local hiring preference. Continued growth of customer-sited resources, including Energy Efficiency (EE), demand response (DR) and solar, deliver meaningful benefits to adopting customers, including energy bill reductions, increased comfort and other non-energy benefits.

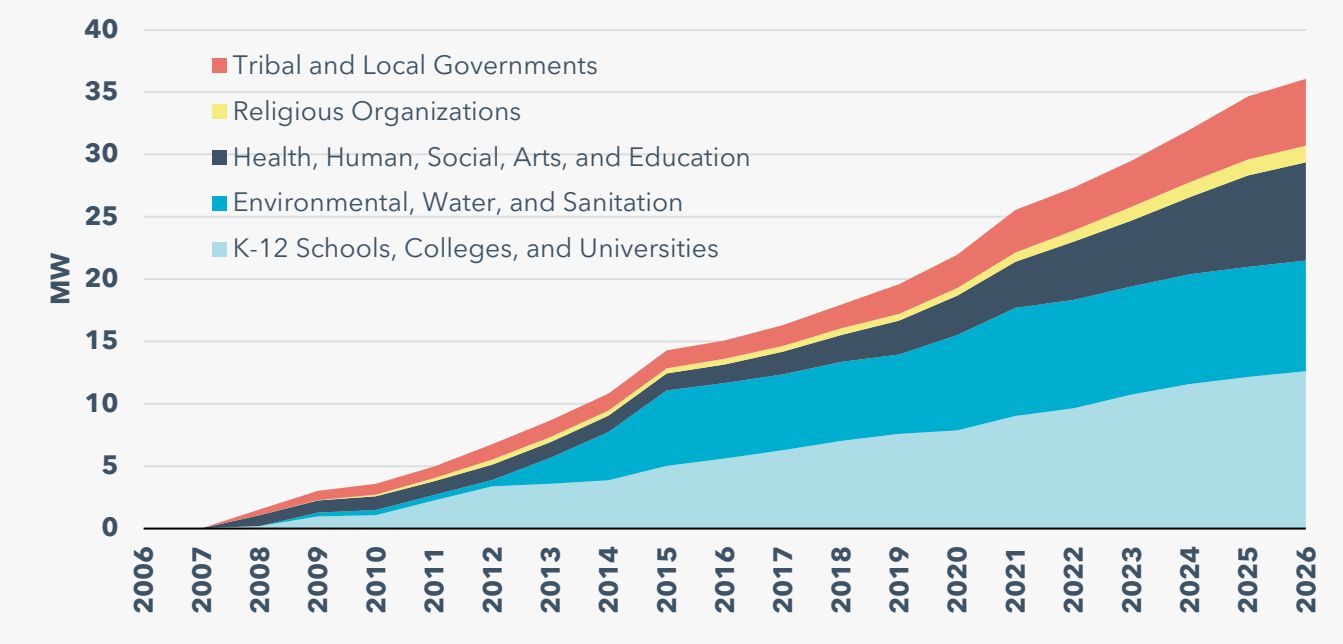
More specifically, HB 2021 directs utilities to review opportunities for Community-Based Renewable Energy (CBRE), inclusive of associated microgrids, storage, DR and infrastructure projects that provide direct benefits to communities as a function of their ownership, a community-benefits agreement, or advancement of resiliency or economic benefits. CBRE as defined by HB 2021 is a broad classification, potentially inclusive of out-of-state transmission-connected utility-scale projects through distribution-connected projects sited behind customer meters. Figure 20 highlights a variety of these facilities within PGE's service territory, though the facilities themselves may not have been intentionally designed to provide broader community benefits.

Figure 20. Current Community-based renewable energy Projects



Deployment of customer-sited CBREs has grown substantially over the past two (2) decades, as shown in Figure 21, supporting nonprofit organizations, education centers, local governments, and Federally Recognized Tribes. As depicted in Figure 21, PGE's existing portfolio of resources already includes over 478 individual projects totaling more than 36 MW of customer-sited CBRE.

Figure 21. Historical Cumulative Customer-Sited CBRE Deployment by Organization Type



Based on continuous resource planning efforts, the ongoing CBRE RFO process, CBIAG coordination work, and associated learnings, PGE's assessment of the costs and opportunities to offset thermal generation with community-based renewable energy has evolved and broadened since 2023. In particular, PGE intends to advance CBREs of all sizes. Behind-the-meter projects, which provide direct customer benefits and are most suited to ownership by governmental, tribal and nonprofit organizations, are a particularly important vehicle to continue delivering community benefits and remain the area where community-led interest and participation are strongest.

Though the acquisition approach is broader, PGE's IRP analysis focuses on a solar plus storage hybrid resource that is less than 20 MW to represent the proxy CBRE available for selection in portfolio analysis. IRP cost assumptions were informed by the 2025 bids in the CBRE RFO and reflect a contracted resource rather than utility ownership. As with other energy resources, development costs of actual solar and storage projects have increased. In addition, experience to date suggests that front-of-the-meter resource acquisitions are more likely to be developer-led, reflecting the scale, expertise, and capital required for project development while behind-the-meter projects continue to offer the greatest opportunities for direct community participation and ownership. The non-selection of CBREs in the cost-optimized portfolio of the rCBI sensitivity analysis[29] indicates that the quantifiable system benefits of this type of CBRE do not result in their selection in least-cost, least-risk planning. There is an opportunity to better align community priorities, project development, and available funding sources so that each can play its intended role in advancing various types of CBREs.

[29] See Section 7.9 rCBI Sensitivity Analysis for more.

Therefore, PGE intends to encourage and assist projects and developers to access supplemental funds to buy down the upfront or ongoing costs, informed by the rCBI analysis framework. Multiple funding opportunities have the potential to be leveraged to support CBRE development, potentially including PGE's Renewable Development Fund, state and federal grant programs, local programs and ETO program funding. PGE also sees opportunity to leverage new surcharges on large loads recently adopted by the OPUC.[30] The new funds may be used to support DERs that mitigate energy burden of residential customers, which offers high opportunity to align with CBRE objectives. CBREs can play an important role in both promoting resilience and facilitating GHG emissions reductions. While the Near-Term Action Plan does not set MW targets for CBRE acquisition, PGE anticipates that opportunities for subsidized front of the meter CBRE deployment may increase as community-centered market development and complementary funding sources are brought into closer alignment.

1.5 PGE's Resource Portfolio Actions

Future planning must account for uncertainty and changing conditions. However, PGE's core priorities remain unchanged: providing safe, reliable, and affordable service while continuing the operational transition to cleaner energy.

As summarized in Section 1.4 and described in more detail in Chapter 2, the approach out of this CEP/IRP cycle includes both specific and intentional planned actions, as well as flexibility to evolve next steps based on customer needs and the emerging planning landscape.

It is important to keep in mind that the modeling that informed this plan is based on assumptions and scenario analysis, available at the time this plan was developed, that assesses future variability and uncertainties. While the near-term Action Plan is meant to represent more tangible activities, PGE's actual ability to procure resources, reduce emissions, and meet load will all be on a real-world, operational basis in conditions that are not yet known. The scenarios shown in this CEP/IRP are intended to guide decision-making focused on least cost, least risk, and in the best interest of customers.

Decarbonizing the system will require significant new investment in clean energy and capacity, as well as in distribution and transmission infrastructure and integration at a pace and scale that is unprecedented. Per IRP planning requirements, the HB 2021 Preferred Portfolio is compliant with HB 2021 emissions targets and demonstrates what it would take on a planning-basis to achieve the statutory emissions reductions. However, resource additions at the scale identified in the HB 2021 Preferred Portfolio introduce a significant volume of execution risks and impacts on customer affordability. Ultimately, PGE's near-term actions are grounded in cost-optimized model results that are more achievable, tempering the pace of resource additions to balance decarbonization progress with affordability, and reducing, but not eliminating, execution risks and concerns.

Guaranteeing that PGE meets HB 2021's 80% carbon emissions target for 2030 would require a substantial volume of resource additions, be highly expensive, and require technology

[30] UM 2377, Order 26-154 at 13

advancement as well as policy changes outside PGE's control. Even if the entire 5,000 MW of 2025 RFP shortlist projects were procured, it would not meet the model-shown needs and significant transmission challenges for bringing that volume of clean energy to PGE's service territory would still exist. Further, the clean technologies today are neither dispatchable nor reliable, requiring additional investment in storage resources to maximize their contribution to the system and maintain reliability.

While the challenges are great, PGE has taken this opportunity to creatively plan ahead and presents in this CEP/IRP a dynamic Action Plan strategy that accounts for these headwinds while continuing to make progress through a range of coordinated actions and with the intention of evolving implementation strategies as the future unfolds, under close oversight from state regulators.

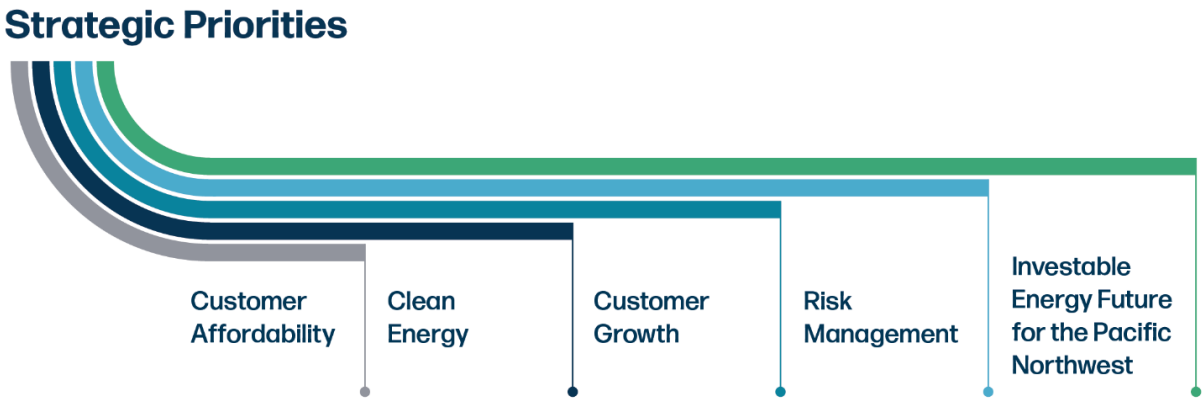
PGE also looks forward to how this plan furthers opportunities to support customer growth across the Company's service area, evolves the traditional utility model, takes actions to mitigate climate impacts, as well as grows community resilience.

1.5.1 Long-term Resource Strategy

PGE approaches resource planning with a simple objective: deliver safe, reliable, affordable and increasingly clean electricity by meeting customer needs while mitigating cost impacts to customers. Rather than treating affordability, reliability and clean energy progress over the planning horizon as competing objectives, PGE evaluates resource decisions through an integrated planning process that strives to balance all three (3).

PGE's long-term resource strategy builds on this approach. It is anchored to PGE's strategic priorities and informed by the results of resource planning analysis. This strategy is designed to clearly identify longer-term actions that support PGE's ability to reduce emissions and serve customers, and their growing demand for energy, at the least-cost and least risk.

Figure 22. PGE's Strategic Priorities



Throughout the planning process, PGE considers strategies necessary for long-term safe, reliable, affordable service that is compliant with state and federal laws. This is inherent in the design of

scenarios analyzed and accompanying assumptions that are all part of the IRP process and modeling analysis. The range of analytical results informs PGE's long-term strategy, with the following subsections describing anticipated actionable findings or existing strategies, woven into PGE business practices now and into the future.

1.5.1.1 Customer Affordability

Affordability is a priority for PGE. Customers are facing economic challenges and rising energy costs have a disproportionate impact on low-income and energy-burdened households. At the same time, Oregon's aging electric infrastructure requires continued investment to maintain safe, reliable and increasingly clean electric service.

Long-term actions identified to support customer affordability include:

- Seek to acquire all available and cost-competitive on-system resources, including energy efficiency and VPP resources, using resource-specific planning, acquisition and regulatory pathways.
- Use VPP resources, Flexible Load Interconnection Analysis, GETs and non-wires solutions, where cost-effective, to increase utilization of existing infrastructure and defer or avoid conventional investments.
- As development of reliability, clean energy and transmission infrastructure accelerates, support fair allocation of costs and risks across all utility and direct access customers. Make sure responsibility for system adequacy is assigned to responsible parties.
- Maintain reliance on existing gas fleet as an affordable reliability backbone through 2040.
- Continue to take actions where growth pays for growth; make sure incremental costs associated with new resources are directed to growing large load customers where appropriate, utilize established mechanisms and tools to allocate costs accordingly.

1.5.1.2 Clean Energy

Adding clean energy allows PGE to reduce reliance on fossil fuels, serving customers with increasingly clean electricity and advancing progress towards decarbonization.

Long-term actions identified to increase the volume of clean energy in PGE's power supply include:

- Rely almost completely on clean energy resources to meet long-term load growth. Acquire viable projects that can capture tax credits where available and optimize use of existing and planned transmission infrastructure. Continue to seek opportunities for dispatchable capacity resources, using existing resources where available and transitioning to emerging technologies as they become commercially available.
- Pursue transmission expansion projects that provide greater access to renewable resources in diverse geographic locations and support a safe, reliable, affordable grid.
- Continue to evaluate, with the CBIAG and other key stakeholders, CBRE procurement frameworks that can allow CBREs to grow while maintaining affordability and strengthening community benefits.

- Seek development of more precise mechanisms for tracking and reporting the emissions content of resources dispatched and allocated through energy markets. Markets serve as a critical tool in balancing both reliability and affordability and can enable clean energy progress with more granular emissions accounting for unspecified purchases.

1.5.1.3 Customer Growth

As Oregon grows, analysis demonstrates that load growth can help improve affordability for all customers. New large-load customers, including datacenters and advanced manufacturers, can help support the transmission and distribution investments needed to serve a growing state by contributing to system costs and increasing utilization of existing infrastructure.

Long-term actions identified that support customer growth in PGE's service area include:

- Center PGE's resource acquisition strategy on reliability, ensuring that appropriate volumes of dispatchable capacity remain to maintain a reliable system that supports growth across all customer classes. Develop and participate in regional reliability programs that ensure that all power suppliers—including utilities and Energy Service Suppliers—bear responsibility, and are allocated appropriate costs and risks, for development of resources that support reliability.
- Integrate VPP expansion with customer growth, including opportunities to design flexibility into new large loads, while advancing PGE's long-term goal for the VPP to meet 25% of peak capacity need by 2030.
- Evaluate opportunities for special contracts with large customers, incorporating flexibility where appropriate and utilizing tools that allocate costs fairly.

1.5.1.4 Investable Energy Future for the Pacific Northwest AND Risk Management

A financially healthy utility is essential because it can attract capital at a reasonable cost, invest in reliability and clean energy infrastructure, manage growth and protect customers from financial risks. PGE's long-term strategy is underpinned by actions that focus on maintaining the Company's financial health, ultimately unlocking the ability to achieve the strategic items for customers identified above.

Long-term actions identified that support an investable future and risk management activities include:

- Pursue state and federal action to address wildfire risk. Unbounded wildfire liability is the single largest risk facing the electric sector. The risk drives up the cost of capital, and in-turn threatens economic development, limits clean energy deployment, and drives higher costs for all customers.
- Continued advocacy for a holding company structure that aligns with industry standards. Oregon's energy needs are growing, and PGE's customers are clear in their prioritization of affordability. The actions identified in this plan will require significant investment for years to come. PGE's near-term Action Plan calls for large volumes of utility-scale solutions, under both the utility-owned and third-party purchase agreement structures. Achievement of PGE's

near-term Action Plan and long-term resource strategy will likely be impacted by PGE's ability to obtain and support financing on favorable terms to support resource acquisitions, transmission investments and other actions needed to continue to serve customers safely, reliably and at the lowest possible cost while continuing to make progress towards PGE's decarbonization targets.

- Continue to seek the Commissions' support in establishing regulatory constructs that reflect the system PGE operates and further PGE's ability to serve customers:
- Power Cost Adjustment Mechanism (PCAM) Reform: the power cost adjustment mechanism was designed when the system ran largely on dispatchable, thermal energy—not the significant volumes of renewables and storage seen today. Furthermore, EDAM participation, described in Section 3.4.1, will shift resource scheduling and dispatch functions to the market operator, reducing PGE operators' ability to influence net variable power costs. Much like PGE's recent datacenter tariff, the power cost adjustment mechanism will need to be adjusted to equitably distribute costs and integrate growing quantities of variable renewables and reduced transmission availability.
- Long-lead time infrastructure and emerging generation require timely regulatory authorization: PGE's IRP analysis demonstrates the need to expand and modernize transmission infrastructure while also preserving access to new generation technologies that may be necessary to meet future reliability, capacity, and decarbonization needs. Transmission projects and emerging generation resources can require significant development expenditures and commitments many years before they are needed, including investments in permitting, interconnection, engineering, land, and long-lead equipment. Traditional regulatory review processes may not align with these development timelines or the increasingly competitive environment for scarce infrastructure, equipment, and development opportunities. Regulatory frameworks that provide appropriate authorization for prudent early-stage investments—while preserving subsequent review of final project costs—will be increasingly important to maintaining viable options and avoiding delays that could increase costs or create reliability risks. Establishing this framework will support developers, as well as other utilities, and position PGE to advance critical transmission projects and emerging generation technologies when needed while maintaining appropriate regulatory oversight and customer protections.
- Streamlining competitive bidding processes: PGE's resource analysis concludes that significant volumes of renewables are needed in the near-term and long-term, and competition for these resources is continuing to increase. Pathways to streamline competitive bidding processes to support nimble acquisition of cost-competitive projects that arise outside of RFP cycles, through waivers of competitive bidding rules provisions or other mechanisms, will be critical in advancing PGE's resource strategy.

PGE will continue to adapt strategies accordingly and engage regulators, stakeholders, and communities on a regular cadence as CEP/IRP updates are submitted and work towards the next full CEP/IRP moves forward.

2 Near-Term Action Plan

PGE developed the Action Plan for the 2026 CEP/IRP based on the key findings of the HB 2021 Preferred Portfolio and Continued Progress Portfolio. This chapter summarizes the key findings observed in portfolio analysis, details the actions identified in the near-term action plan and discusses acquisition and timing considerations for key procurement activities.

Chapter Highlights

- PGE's near-term Action Plan is built to provide flexibility. The action plan was informed by the HB 2021 Preferred Portfolio and the Continued Progress Portfolio, providing a range to inform near-term decisions. This flexibility is critical in supporting PGE's ability to move quickly and adapt to changes in the planning environment as PGE moves forward.
- The Action Plan differentiates between important demand-side and supply-side activities. Energy efficiency and Virtual Power Plant resources are important as PGE continues to maximize the use of the existing system. Utility-scale clean energy projects that provide non-emitting energy and capacity and maximize transmission availability are also critical.
- New transmission development can no longer be deferred. This Action Plan includes specific transmission projects that require near-term action to support longer-term needs.

2.1 Action Plan Background

2.1.1 Portfolio Analysis Overview

PGE's portfolio analysis serves as the analytical foundation for recommending a discrete and appropriate list of near-term actions. In portfolio analysis, informed by stakeholder input, PGE modeled optimized resource portfolios, subject to alternative sets of assumptions selected to test the most critical questions PGE faces in long-term planning. PGE evaluated the performance of each portfolio—each comprised of a unique set of resource outcomes over time—against a set of metrics, allowing comparison of costs, greenhouse gas emissions and other outputs over time. Detailed discussion of the methodologies and results of these analysis workstreams are woven throughout the IRP, especially in Chapters 4 through 7 and referenced appendices.

Based on this analysis, the HB 2021 Preferred Portfolio presents the least-cost, least-risk pathway set of resources needed to continue to meet resource adequacy needs while fully decarbonizing in accordance with HB 2021 emission reduction targets. This portfolio identified an additional 6.7 GW needed by 2030 to reach 80% emissions reductions, growing to 9 GW of resource additions by 2032 to stay on the glidepath as PGE progresses towards the next target in 2035. As discussed in Chapter 1, the HB 2021 Preferred Portfolio's pace of resource additions presents major challenges, both in terms of achievability, regional transmission infrastructure, and affordability impacts. Furthermore, the analysis cannot account for all costs associated with building and integrating necessary resources, as topics such as distribution costs are out of scope.

Recognizing the cost and feasibility implications of the HB 2021 Preferred Portfolio glidepath, PGE, with stakeholder input, designed an alternative portfolio to explore a path that works to reduce the

execution and affordability risks identified in the HB 2021 Preferred Portfolio, referred to as the Continued Progress portfolio. In this alternative portfolio, PGE's compliance with HB 2021 is assumed to occur through an alternate path, instead of full achievement of emission reduction targets. However, this portfolio still prioritizes large deployment of renewable, storage and DERs to meet needs, adding 3.4 GW by 2030, growing to over 5 GW by 2032, and achieves significant emissions reduction in the next five (5) years—proving that decarbonization progress remains steady. For information on methodological assumptions used in the construction of this portfolio, see Section 7.3 and Appendix Section H.6.5.

Resource acquisition outcomes identified in the HB 2021 Preferred Portfolio and Continued Progress portfolio inform the 2026 CEP/IRP Action Plan. The Action Plan describes steps that PGE intends to take over the next five years based on portfolio analysis (see Section 2.1.2 with additional detail in Chapter 7 and PGE's long-term resource strategy (See Section 1.5.1). The Action Plan presents MW ranges as desired outcomes for PGE's continuing resource acquisition activities. PGE aspires to the higher resource amounts associated with the HB 2021 Preferred Portfolio, but the Action Plan presents ranges inclusive of Continued Progress Portfolio pathways in anticipation of potential feasibility and affordability challenges.

PGE's flexible Action Plan allows the Company to adapt to current planning conditions while prioritizing decarbonization, affordability, and management of execution risk for resources. It also preserves flexibility within the Action Plan should market conditions evolve. If emerging technologies mature more rapidly, federal policy support changes, or broader macroeconomic conditions improve, PGE can increase procurement activity as needed to remain on track toward achieving the greenhouse gas emissions reduction targets established under HB 2021. However, if PGE cannot limit exposure to wildfire risk and implement a holding company structure that provides more financing capacity, options and supports greater financing flexibility, PGE may not be able to accomplish the actions identified in a way that supports customer affordability and maintains the financial health of the utility. PGE will continue to prioritize transparency and engagement with customers, communities and regulators throughout the Action Plan time horizon as we assess procurement options and evaluate the resource outcomes that best meet customer and policy needs. PGE will continue to engage with external stakeholders through the CEP/IRP Update process and any relevant procurement efforts.

2.1.2 Portfolio Analysis Key Findings

Comparison of the HB 2021 Preferred Portfolio and Continued Progress Portfolio serves as the basis for PGE's near-term action plan, as PGE seeks to prioritize the near-term actions that advance progress toward both portfolios to the extent possible. Findings are further informed by comparison to alternative portfolios—such as those created when key resources or transmission links are not available, when large load growth is excluded from planning, or when the scope is limited solely to reliability needs. This immense body of analytical work yields key findings which inform

PGE's actions. Table 2 summarizes the key findings emerging from portfolio analysis that shape the construction of the Near-Term Action Plan, supported by further detail in Chapter 7.

Table 2. 2026 CEP/IRP Key Findings

Key Finding	Implication for Action Plan
Continued deployment of current generation technologies delivered to PGE using near-term transmission service plans can meet reliability needs over the upcoming five years.	A portfolio predominantly reliant on wind, solar, and storage additions delivered over BPA's system will continue to deliver the most affordable, reliable, energy while enabling continued progress toward HB 2021 decarbonization targets. Modelled portfolios tend to include hybrid batteries rather than on-system standalone batteries, and the Action Plan will prioritize hybrid resources to the extent possible. (see Section 7.11, Portfolio Reliability)
Near-term clean energy deployment enables emissions reductions, but costs and challenges of incremental reductions increase beyond 60% by 2030. This indicates concerning customer affordability impacts from the remaining 20% of reductions.	PGE seeks to pursue a balanced strategy to maintain a least-cost, least-risk portfolio. Resource outcomes in the Action Plan are presented as ranges to encompass portfolios which temper the pace of renewable additions to continue progress towards decarbonization targets but keep customer affordability front and center. (see Section 7.9 and Section 7.6.1).
Cost-effective energy efficiency and growth of the Virtual Power Plant is foundational.	The Action Plan reemphasizes commitment to actions that advance available and cost-competitive EE, DERs, and customer-sited resources. (see Section 6.2 and Section 7.10)
CBREs may provide customer and community benefits but are not widely selected in portfolios that seek to optimize a least-cost, least-risk system.	PGE remains committed to consideration of CBREs on a planning-basis, and reemphasizes the importance of accessing external funding, aligning with SSR progress, and providing tangible benefits vetted by the CBIAG, which may occur outside of planning-related processes. (see Section 7.9)
Renewable-storage hybrid projects utilizing existing BPA transmission service plans and capable of capturing tax credits offer high value.	Acquisition actions should prioritize wind/solar/storage hybrid projects, including optimization of existing resources, to capture tax credits, increase utilization of limited transmission, and provide energy and capacity to PGE's portfolio. (see Section 7.4).
Additional clean energy needs to serve large load growth will provide system benefits while being allocated to large customer rates through ratemaking process.	Serving new large load growth contributes to PGE's resource needs on a planning basis, with the growing segment responsible for associated costs. New IRP analysis of cost allocation indicates that tracking and allocating costs through the peak growth modifier mechanism and special contracts where applicable can reduce rate pressure for other customer classes. (see Section 7.4.2)
PGE's thermal fleet provides valuable system benefits through the 2030s.	Even with reduced capacity factors, continued availability of PGE's natural gas portfolio is consistent with continual progress toward HB 2021 and necessary to maintain a reliable system. Where available, near-term contracts with additional gas resources may be necessary in the absence of other capacity resource availability. (see Section 7.4)
Transmission expansion is needed to maintain long-term reliability and support further renewable development and access to markets.	Regional transmission projects must be advanced in the Action Plan horizon to meet scheduled 2032-2035 in-service dates. North Plains Connector, Warm Springs Power Pathway and Harborton-Trojan #3 contribute to least-cost, least-risk portfolio progress. Increasing access to new transmission reduces costs, variability risk and resource needs, reducing procurement-related risks (see Section 7.4.4).
Emerging non-emitting capacity resources are needed in the second half of the planning horizon to maintain decarbonization progress.	PGE should consider options to gain familiarity with emerging technologies, which may not yet be cost-effective nor commercially available, but serve an important role for maintaining reliability while making progress towards clean energy targets in 2035 and beyond. (see Section 7.4).

2.2 Near-Term Action Plan

PGE's Near-Term Action Plan (Action Plan) describes priority actions through 2032 needed to meet identified system needs on a planning-basis and in the context of the evolving planning and policy environment. The electric utility landscape is shifting at an unprecedented pace, driven by rising

demand, and rapidly changing federal policy, as well as changing market conditions, resulting in significant impacts to clean resource costs and technological advancements.

The Action Plan presents a framework that PGE will revisit in future CEP/IRP Updates. The Action Plan is anchored to need assessments described in this CEP/IRP. PGE anticipates keeping analysis methodologies fixed while updating input assumptions as PGE's system and the external landscape evolves, in alignment with OPUC rules and guidance. PGE intends to take least-cost, least-risk actions, to acquire needed resources timely, with outcomes dependent on market conditions and PGE's evolving portfolio at the time of decision-making. Table 3 presents PGE's Action Plan, with supporting context for each group of actions provided in the following subsections.

Table 3. Near-Term Action Plan

No.	Objective	Action
Energy Efficiency Action		
1.1	Acquire cost-effective energy efficiency	Fund Energy Trust of Oregon via Multi-Year Planning framework
Virtual Power Plant Actions		
2.1	Pursue available cost-effective flexible load and dispatchable distributed resources that customers choose to provide.	Pursue winter and summer capacity from existing programs and pilots, as established in the VPP Multi-Year Plan. Reevaluate non-cost effective opportunities in future planning. Integrate large load flexibility through plan of service requirements. Explore opportunities to use Non-Wires Solution projects to address locational needs.
2.2	Maximize resource value of customer-sited solar, with emphasis on increased VPP capabilities.	Prioritize storage pairing, prioritize community benefits. Investments to support customer-friendly application and enrollment process.
Community-based renewable energy and Small-Scale Renewables Actions		
3.1	Seek projects with tangible community benefits across procurement pathways.	Deploy CBRE through customer programs and resource procurement actions, where cost -competitive. Develop pipeline of projects that provide tangible community benefits, with supplemental funding sources. Build out rCBI framework to inform funding partnerships for projects that provide tangible community benefits and ownership opportunities for local governments, tribes, or nonprofit organizations.
3.2	Acquire SSR-eligible resources.	Maintain SSR progress through contributions from QFs, CBREs, projects promoted by large load service plans, and if eligible, PGE-procured and VPP-integrated customer-sited resources. Issue SSR RFP in 2027 seeking up to the 2030 target volume of SSR-eligible resources if cost-competitive.
Utility-Scale Resource Actions		

No.	Objective	Action
4.1	Acquire firm and dispatchable capacity contracts.	Continue multipronged procurement strategy: ▪ 2025 RFP FSL transactions; ▪ Bilateral actions (including 2026 PPA All-call); ▪ Large load special contracts (where appropriate). Where appropriate, prioritize projects with firm transmission plans, and tax credit eligibility.
4.2	Acquire approximately 3,000 MW of wind, solar, and hybrid battery storage that maximize use of existing transmission service plans.	
4.3	Acquire an additional 1,800 to 5,700 MW of wind, solar, and hybrid battery storage, informed by resource acquisition progress, ongoing assessments of needs, and project costs.	Issue one or more all-source RFPs; Large load special contracts (where appropriate).
Transmission Actions		
5.1	Leverage Grid Enhancing Technologies (GETs) to enhance local transmission.	Execute GETs strategy, including continued deployment of Dynamic Line Rating sensors and advanced conductor coating applications for transmission lines.
5.2	Advance development of the Warm Springs Power Pathway project in collaboration with Confederated Tribes of the Warm Springs to assure reliability and access diverse renewables.	Continue development activities, by entering into agreements to support permitting, engineering design, procurement, construction, and community engagement actions.
5.3	Support development of North Plains Connector to access diverse renewables and markets.	Enter into definitive agreements with project developer for purchase of capacity and option to purchase interest in the line, subject to appropriate regulatory approval and other conditions precedent.
5.4	Advance development of the Harborton-Trojan #3 project to assure reliability and access diverse renewables.	Continue development activities, by entering into agreements to support permitting, engineering design, procurement, construction, and community engagement actions.
5.5	Maintain options for additional transmission informed by resource acquisition progress, ongoing assessments of needs, and project costs.	Explore additional regional transmission options to access diverse renewables and non-emitting resources.
Resource Planning Actions		
6.1	Publish two (2) annual CEP/IRP Updates to this 2026 CEP/IRP.	File 2026 CEP/IRP Updates, currently planned to be on or before Oct. 15, 2027, and Oct. 15, 2028.
6.2	Publish next CEP/IRP.	File 2029 CEP/IRP, currently planned to be on or before Oct. 15, 2029.

The following sections provide context for the Near-Term Action Plan depicted in the table above.

2.2.1 Energy Efficiency Action

Cost-effective energy efficiency (EE) in Oregon is acquired through programs funded by utility customers and administered by Energy Trust of Oregon (ETO). EE provides valuable system benefits which are especially critical in the context of the headwinds facing other resource types. PGE will continue to coordinate with ETO on effective deployment and administration of EE programs and funds through ETO's Multi-Year Plan development process. According to ETO analysis, cost-effective EE implemented in 2027 through 2031 is currently forecasted as cumulative savings of approximately 182 MWa, an average pace of incremental deployment of about 36 MWa per year (see Section 6.2.4). This cost-effective EE was included in the load forecasts used for all scenario analysis and is the basis for the Action Plan. By comparison, portfolio analysis identified cumulative adoption of just 1 to 13 MW of non-cost-effective EE, depending on scenario, through 2032. Therefore, annual targets of the Action Plan focus on continued actions to acquire cost-effective EE, within the fixed five-year budget established by ETO's 2026-2030 Multiyear Plan. This budget forecasts a $219 million average annual cost to PGE customers, responsible for an estimated 5.5% increase of a typical residential customer's bill on an average basis.

PGE's collaboration with ETO has matured significantly, with collaboration on co-delivery, co-marketing and co-development activities to deploy a variety of customer offerings. Changes to avoided costs through annual updates will influence how EE funding is allocated among programs and measures within ETO's fixed budget. The adaptive management framework provides flexibility to respond to changing market conditions in balancing program and portfolio cost-effectiveness, pilot goals, and programs focused on equity and energy burden outcomes. Additionally, to the extent specified community benefits and small-scale renewable projects are directed by state policy, PGE encourages a process with OPUC and ETO to explore opportunities to leverage ETO programs to offset SSR and CBRE cost premiums.

Effective management also requires clarification of decision criteria to improve transparency, accountability and stakeholder confidence. PGE intends to continue to advocate for further development of quantitative metrics within performance measurement frameworks, articulation of guardrails for non-cost-effective programs, and additional transparency. PGE also sees opportunities to improve program effectiveness through greater transparency of practices between ETO and PGE, particularly to support income-qualified customers. These refinements will build upon an already strong partnership and help ensure that the multiyear plan delivers both accountability and maximum value for customers over the planning horizon.

Table 4. Energy Efficiency Action through 2032

No.	Objective	Action
1.1	Acquiring cost-effective energy efficiency	Fund Energy Trust of Oregon via Multi-Year Planning framework

2.2.2 Virtual Power Plant Actions

PGE's VPP is a grid-integrated resource that orchestrates more than 600 MW of capacity from over 250,000 enrolled customers across a portfolio of programs for all customers. The VPP uses integrated customer and grid technology platforms to provide energy, capacity and grid services. PGE's VPP vision is presented in Section 1.2.4. Analysis methodologies and findings for VPP

resources are described in Section 7.10. As discussed in Section 7.10, PGE's analysis reveals significant portfolio value of existing flex load programs and pilots (Bins 1, 2, and 3). Additional opportunities assessed through IRP analysis for emerging flex load resources are sensitive to cost assumptions, resulting in more limited portfolio selection. These findings provide support for future VPP resource volumes inclusive of all available growth of existing programs and pilots, with more limited contributions of emerging opportunities:

- All available growth of currently cost-effective, existing large-scale programs, estimated to provide an incremental 43 MW (summer), 21 MW (winter) by 2032 for flex load programs and pilots, in addition to 219 MW of Dispatchable Standby Generation (DSG).
- All available growth of currently existing smaller scale programs and pilots, estimated to provide incremental 8 MW (summer), 5 MW (winter) by 2032.
- Measured growth of forward-looking VPP measures which have high technical and market potential, estimated to provide approximately 3 MW (summer), 4 MW (winter) by 2032.
- Additional flexibility associated with integration of large loads.
- Continued growth of customer-sited (customer side of utility meter) solar, with reference case forecast growth of 9 MWa during the Action Plan horizon. While not dispatchable, PGE classifies customer solar as a VPP resource. Details of the solar adoption forecast, which is subject to continuing updates, are found in Section 6.2.2.3.

Annual acquisition volumes for all VPP resources will depend on evolving cost-effectiveness forecasts and demonstrations presented in VPP Multi-Year Plans and reported in program-specific tariff and deferral approval filings.

Table 5. Virtual Power Plant Actions through 2032

No.	Objective	Action
2.1	Pursue available cost-effective flexible load and dispatchable distributed resources that customers choose to provide.	Pursue winter and summer capacity from existing programs and pilots, as established in the VPP Multi-Year Plan. Reevaluate non-cost-effective opportunities in future planning. Integrate large load flexibility through plan of service requirements. Explore opportunities to use Non-Wires Solution projects to address locational needs.
2.2	Maximize resource value of customer-sited solar, with emphasis on increased VPP capabilities.	Prioritize storage pairing, prioritize community benefits. Investments to support customer-friendly application and enrollment process.

2.2.3 Community-Based Renewable Energy and Small-Scale Renewables Actions

In response to regulatory and policy expectations, the Action Plan includes CBRE and SSR acquisition actions. These resource categories may have synergies with the VPP if deployed on

PGE's system and integrated in the VPP but could potentially be off-system or subject to different requirements.

Modeling results show that inclusion of CBRE and SSR growth in resource portfolios increases total costs, due to their higher costs than comparable utility-scale alternatives. As described in Section 7.6. PGE's SSR compliance requirement grows in proportion to resource additions. PGE seeks to acquire projects where cost competitive as described in Table 6. However, CBRE resources, given their forecasted high costs, are not selected in the near-term window of the Continued Progress portfolio. Modest volumes of CBRE are selected in the near-term of the HB 2021 Preferred Portfolio given the significant resource needs of that portfolio. Increased volumes of CBRE resources are selected later in the planning horizon across both key portfolios, emphasizing the importance of continuing to work with communities and stakeholders on refining the procurement strategy for these resources as part of PGE's long-term strategy.

The Action Plan also emphasizes the importance of accessing supplemental funding in the near-term to offset the associated cost premiums where projects provide tangible community or policy-related benefits, as described in Section 1.4.4. Opportunities for CBRE. Portfolio analysis finds the following resource additions within the action plan horizon:

- Up to 27 MW of CBRE through 2032, depending on scenario
- Approximately 448 to 669 MW of small-scale renewables needed for the 2030 initial compliance year

PGE's next phase of CBRE development builds on the foundation established through PGE's initial RFO and the work of the CBIAG (as described in Section 6.3.4), while evolving toward a more community-led and affordability-focused model. PGE can provide procurement pathways, technical expertise, system-value analysis, and a potential long-term offtake; communities and project sponsors can increasingly lead the identification of desired benefits, project partnerships, and external funding. In many cases, customer-sited resources may offer the greatest opportunities for direct community participation and ownership and will continue to be promoted through PGE customer programs and further explored as part of PGE's long-term resource strategy.

Selection of the proxy CBRE resource type—a 20 MW solar-storage hybrid - in optimized portfolios is highly dependent on both the assumed availability of a subsidy for the above-market cost and the availability assumptions of both CBRE and comparable utility-scale resources (Section 7.9). Both areas of uncertainty warrant flexibility in PGE's Acton Plan. As PGE seeks to match incremental cost of CBRE with equivalent incremental system value or supplemental funding, available CBRE amounts may prove lower or higher than PGE's IRP assumptions, warranting adjustment to procurement expectations.

This balanced approach of the Action Plan reflected in Table 6 can allow CBRE procurement to grow while maintaining affordability, strengthening community ownership of project outcomes, and ensuring that customers receive both measurable community benefits and meaningful system value from the resources they fund.

Table 6. Community-based renewable energy and Small-Scale Renewables Actions through 2032

No.	Objective	Action
3.1	Seek projects with tangible community benefits across procurement pathways.	Deploy CBRE through customer programs and resource procurement actions, where cost competitive. Develop pipeline of projects that provide tangible community benefits, with supplemental funding sources. Build out rCBI framework to inform funding partnerships for projects that provide tangible community benefits and ownership opportunities for local governments, tribes, or nonprofit organizations.
3.2	Acquire SSR-eligible resources.	Maintain SSR progress through contributions from QFs, CBREs, projects promoted by large load service plans, and if eligible, PGE-procured and VPP-integrated customer-sited resources. Issue SSR RFP in 2027 seeking up to the 2030 target volume of SSR-eligible resources if cost-competitive.

2.2.4 Utility-Scale Resource Actions

Utility-scale resources comprise the majority of resource addition needs in this Action Plan. As demonstrated in portfolio and sensitivity analysis, resource needs are highly variable. They vary based on factors including pace of load growth, project attributes, transmission availability, and clarification of regulations applicable to the HB 2021 Section 10[31] and/or other offramp provisions. PGE's Action Plan has been designed to reflect the inherent uncertainties that can arise through the resource procurement process, utilizing a range of nameplate capacity to capture the volume of resources needed to achieve desired outcomes. Consistent with PGE's historical practices, specific energy and capacity contributions will be determined through the least-cost, least-risk procurement process.

Portfolio analysis indicates 4,800 to 8,700 MW of wind, solar, and storage resources added through 2032 (including any projects that may be contracted from the 2025 RFP Final Shortlist). As a complement to these additions, portfolio analysis also demonstrates the contributions of firm and dispatchable capacity contracts where available to manage PGE's near-term reliability positions in a least-cost, least-risk manner. As discussed in Section 7.6, the Continued Progress Portfolio uses 137 MW of contracted natural gas generation capacity to satisfy reliability needs in 2027 and beyond. Similarly, analysis conducted via portfolio sensitivities concludes that near-term hydro contracts also help reduce portfolio costs and lower resource needs, offsetting significant amounts of new resource development in all cases evaluated (Section 7.4.3) discusses analysis of 200 MW of hydro contracts). While nameplate amounts of any specific resource type remain subject to change based on resource availability, cost, and portfolio needs, these findings support the near-term action of acquiring firm and dispatchable capacity contracts, when available, through PGE's least-cost, least-risk procurement framework.

[31] https://olis.oregonlegislature.gov/liz/2021r1/Downloads/MeasureDocument/HB2021/Enrolled

Nameplate resource outcomes for development of new utility-scale resources assume balanced progress of wind, solar and hybrid storage technologies, with attention to geographic diversity, optimization of existing interconnection and transmission rights, and tax credit eligibility at least through 2030 to align with portfolio reliability and affordability modeling. While not selected in portfolio optimization through 2032, PGE also remains open to acquisition of other commercially mature non-emitting technologies that meet least-cost, least-risk expectations, as well as opportunities to gain experience with emerging technologies.

To meet reliability needs, and continue progress toward the 2030 GHG emissions target, PGE will pursue a multipronged procurement strategy to acquire available and cost-competitive resource options as summarized in Table 7. PGE's strategy and portfolio results emphasize the importance of expeditiously procuring 3,000 MW of renewables and storage to align with 2025 RFP negotiation opportunities, address near-term needs, and capture tax credits. PGE will then continue to seek non-emitting resources through additional procurement avenues to align with the range of resource needs identified by the Continued Progress Portfolio and HB 2021 Preferred Portfolio over the action plan horizon. In both procurement phases, customer demand for clean energy via large load special contracts, Green Future Impact, and other programs can provide a pathway to procure additional renewable projects when available, supporting participating customers' continued commitment to clean energy and furthering PGE's ability to reduce emissions on the system. Section 2.3 provides further details on PGE's intended scope and timing for these actions. Specific MW needs for procurement will continue to evolve as acquisition actions and load forecasts progress.

Table 7. Utility-Scale Resource Actions through 2032

No.	Objective	Action
4.1	Acquire firm and dispatchable capacity contracts.	Continue multipronged procurement strategy: ▪ 2025 RFP FSL transactions; ▪ Bilateral actions (including 2026 PPA All-call); ▪ Large load special contracts (where appropriate). Where appropriate, prioritize projects with firm transmission plans, and tax credit eligibility.
4.2	Acquire approximately 3,000 MW of wind, solar, and hybrid battery storage that maximize use of existing transmission service plans.	
4.3	Acquire an additional 1,800 to 5,700 MW of wind, solar, and hybrid battery storage, informed by resource acquisition progress, ongoing assessments of needs, and project costs.	Issue one or more all-source RFPs; Large load special contracts (where appropriate).

2.2.5 Transmission Actions

Planning analysis demonstrates that expanding the transmission network and upgrading aging transmission infrastructure is needed in the near-term and long-term. Transmission projects are critical to access diverse renewable non-emitting resources, and support a safe, reliable and affordable grid.

PGE faces decisions on key projects during the 2026 CEP/IRP Action Plan timeframe. However, as PGE described in its recently filed 2027 General Rate Case (GRC), changes to Oregon's regulatory

framework will be critical to support utility investment in long-lead time infrastructure such as transmission lines. PGE encourages development of an appropriate regulatory framework, allowing approval of eligible projects with appropriate customer protection before construction begins and has requested that the Commission open an investigation with the aim of establishing this framework.[32]

Table 8. Transmission Actions through 2032

No.	Objective	Action
5.1	Leverage Grid Enhancing Technologies (GETs) to enhance local transmission.	Execute GETs strategy, including continued deployment of Dynamic Line Rating sensors and advanced conductor coating applications for transmission lines.
5.2	Advance development of the Warm Springs Power Pathway project in collaboration with Confederated Tribes of the Warm Springs to assure reliability and access diverse renewables.	Continue development activities, by entering into agreements to support permitting, engineering design, procurement, construction, and community engagement actions.
5.3	Support development of North Plains Connector to access diverse renewables and markets.	Enter into definitive agreements with project developer for purchase of capacity and option to purchase interest in the line.
5.4	Advance development of the Harborton-Trojan #3 project to assure reliability and access diverse renewables.	Continue development activities, by entering into agreements to support permitting, engineering design, procurement, construction, and community engagement actions.
5.5	Maintain options for additional transmission informed by resource acquisition progress, ongoing assessments of needs, and project costs.	Explore additional regional transmission options to access diverse renewables and non-emitting resources, and, where appropriate, enter into definitive agreements with project developer for purchase of capacity and options to purchase interest in the line(s).

2.2.6 Resource Planning Actions

Resource planning is a continuous practice based on best-available assumptions at the time of analysis. PGE will continue to track progress and refine methodologies, with subsequent reporting using the annual schedule of CEP/IRP and Update filings, consistent with OPUC rules.

Table 9. CEP/IRP Actions

No.	Objective	Action
6.1	Publish two (2) annual CEP/IRP Updates to this 2026 CEP/IRP.	File 2026 CEP/IRP Updates, currently planned to be on or before Oct. 15, 2027 and Oct. 15, 2028.
6.2	Publish next CEP/IRP.	File 2029 CEP/IRP, currently planned to be on or before Oct. 15, 2029.

[32] See Exhibit 1500, Long Lead Time Infrastructure and Resource Framework in PGE's 2027 General Rate Case Testimony in OPUC UE 473.

2.2.7 Regional Initiatives

As the planning environment evolves, new regional market structures play an important role in PGE's access to cost-competitive energy and capacity. While not evaluated as resource actions in this CEP/IRP analysis, critical enabling actions include:

- Market GHG Emissions Reporting: With PGE's participation in CAISO's Extended Day-Ahead Market (EDAM) going live in October 2026, PGE will be a full participant in a regional market. PGE intends to continue its participation in stakeholder processes, including at CAISO and Oregon DEQ, with the intention of improving the alignment of emissions reporting associated with markets.
- Resource Adequacy (RA) Framework: To access a resource adequacy program to improve efficiency of capacity planning, PGE continues to actively engage in efforts to develop and ultimately participate in a regional program, currently being advanced through the development of the EDAM-aligned RA Program framework. See further details in Section 3.4.4.
- In each case, inter-organizational implementation actions are in progress; PGE is not seeking acknowledgement of these actions in this IRP.

2.3 Resource Acquisition Timing and Coordination

PGE intends to proceed expeditiously to acquire EE and VPP resources through program and resource-specific pathways. This section expands on Section 2.2.4 to describe near-term timing and process expectations for efforts to develop new cost-competitive energy and capacity resources.

2.3.1 Near-Term Procurement Actions

Consistent with the Commission's encouragement in its 2025 RFP shortlist acknowledgement and recent executive orders by Oregon's governor,[33] PGE continues to evaluate all opportunities to advance viable clean energy projects that can benefit customers and maintain HB 2021 progress.

PGE's ongoing diligence and negotiations of 2025 RFP shortlisted projects have demonstrated that several projects continue to face material development constraints, including interconnection, transmission, permitting, and other development risks, that are likely to delay commercial operation beyond the dates assumed in their bids and, in some cases, into the 2030s. (Section 3.2 and Section 6.3.3 include additional detail on these challenges).

In the current environment, projects with the capability to meet 2029-2030 CODs are actively at risk for two (2) reasons. First, large-load buyers, and datacenters in particular, can offer developers terms a regulated utility bound by long and protracted processes cannot match, and can absorb the price changes and delays imposed by federal permitting and transmission uncertainty. Hence a project PGE cannot quickly procure is a project a datacenter may acquire instead. Second, many projects that may have a viable development opportunity could see schedule and cost uncertainty

[33] OPUC Order 26-194 in Docket UM 2371, 18 May 2026. EO 25-25 and EO 25-29 (Oct. 2025 and Nov. 2025).

increase materially if contracting and construction starts do not occur quickly, potentially leading developers to abandon opportunities facing increasing uncertainty.

In the context of these challenges, and a diminishing window to develop tax credit eligible renewable projects, PGE seeks all available opportunities to supplement 2025 RFP negotiations with complementary near-term procurement. PGE has been an active participant in discussions with Staff and regulatory stakeholders regarding options for accelerated procurement and increased commercial flexibility while retaining process that ensure prioritization of least cost, least risk opportunities. The Company looks forward to sharing additional details about near-term actions in an appropriate venue when available.

In alignment with these goals, PGE is also seeking Commission approval for PGE to continue negotiations with a utility-scale 199 MW solar photovoltaic array paired with a 199 MW 4-hour battery energy storage system being advanced on the Warm Springs Reservation by Warm Springs Power & Water Enterprises (WSPWE), the enterprise that manages the energy assets of the Confederated Tribes of Warm Springs (CTWS).[34] This is a tribally initiated project that remains subject to the Tribe's development review and approval process. PGE understands that the project could support CTWS's participation in energy resource and infrastructure development in a manner that advances Tribal sovereignty, cares for tribal natural and cultural resources for future generations, creates durable economic value, builds Tribal leadership and Tribal workforce in the energy sector, and advances opportunity for greater Tribal ownership and control of energy infrastructure. The project would build upon the decades-long relationship between PGE and CTWS centered on the jointly owned Pelton Round Butte Hydroelectric Project and provide an opportunity to extend that partnership by optimizing the existing hydroelectric generation through integration of solar and battery storage. The project proposes an interconnection associated with Pelton Round Butte through a substation bay owned by CTWS. This Tribally owned position is a significant, site-specific development attribute that creates a unique opportunity to integrate new resources with existing energy infrastructure on the Warm Springs Reservation. If approved and developed, this project is anticipated to provide PGE's customers with clean, reliable, cost-effective, and tax-credit-eligible capacity that advances PGE's progress toward meeting identified resource needs, as further evaluated in this CEP/IRP, and complements PGE's ongoing competitive procurement processes.

2.3.2 Bilateral Energy and Capacity Contracting

Mid-Columbia hydro contracts have historically provided clean, low-cost, and high-capacity contribution to PGE customers. As existing contract expirations approach, PGE faces increased competition from large load customers and other entities for new agreements.

IRP portfolio results show significant affordability and emissions benefits when additional long-term hydro capacity is available to PGE's portfolio. For example, availability of 200 MW of hydro was associated in portfolio modeling with avoidance of nearly 800 MW of otherwise necessary new renewable and storage resources by 2030, compared to the HB 2021 Preferred Portfolio (see

[34] OPUC Docket No. UM 2471, PGE request for waiver filed 30 Sep, 2026.

Section7.4.3.1). The inclusion of natural gas contract capacity in the Continued Progress Portfolio provides similar reliability and affordability benefits.

In this context, PGE has entered into new agreements for two (2) new 10-year PPAs which provide PGE access to Columbia River hydro beginning in 2027, as described Appendix Section F.2.3.1. These new PPAs allow PGE to manage near-term open energy and capacity positions in the context of exits of other hydro contracts from PGE's portfolio. Due to the execution timing of these agreements, these PPAs are not included as existing resources in PGE's 2026 IRP modeling.

Accounting for the new hydro PPAs, analysis results continue to show remaining near-term capacity needs and portfolio value associated with securing access to existing facilities, whether hydro, gas contracts, and renewable resources. PGE continues to explore opportunities for cost-competitive energy and capacity contracts aligned with 2026 IRP portfolio results.

2.3.3 All-Source RFP

Consistent with Action Plan item 4.2 in Table 7, PGE also intends to pursue acquisition of new wind, solar, storage and other cost-competitive non-emitting projects via one or more future All-Source RFPs pursuant to OPUC's competitive bidding rules.

- PGE's approach to its next RFP seeks to build on PGE's experience in the recently completed 2023 and 2025 procurement cycles. To reduce the burden on participating project developers and loss of projects to competitors, PGE continues to encourage more streamlined and flexible procurement processes that prioritize viable projects aligned with PGE's Action Plan and current market conditions. Updated processes also need to incorporate sharpened viability assessments (see discussion in Section 2.3.1). PGE's approach will also be informed by any revised regulatory guidance advanced by the Commission's forthcoming EO 25-25 and EO 25-29 implementation work plan.[35]
- PGE intends to issue its next RFP following Commission acknowledgement of the 2026 IRP. These plans remain subject to change.

[35] Docket UM 2417

3 Planning Environment

This chapter reviews policy, technology, economic and industry dynamics that inform and constrain PGE's planning. These dynamics are incorporated into IRP analysis input and methodological assumptions, which are referenced throughout the chapter.

Chapter Highlights

- Affordability remains a priority as the cost and risk of resource development increase. Changing federal tax policy, tariffs, supply-chain constraints, long equipment lead times and increasing competition for viable projects are affecting both resource costs and availability.
- Load growth creates opportunity to spread the cost of decarbonization over a larger base, decreasing its cost impacts, but its timing and magnitude are increasingly uncertain. Datacenters, electrification, and broader economic growth can expand the customer base and improve system utilization, but proposed and adopted moratoriums, permitting restrictions, economic conditions, and changing customer commitments require PGE to maintain flexibility in the timing of resource and infrastructure investments.
- Resources that are capable of generating and delivering energy when called upon are becoming increasingly valuable. Growing demand, multi-day winter reliability risks, transmission constraints, and declining incremental capacity contributions from additional variable resources increase the importance of resources capable of reliably serving customers during periods of system stress.
- Resource availability can no longer be assumed. PGE increasingly competes with utilities and large energy users for a finite pool of tax-advantaged renewable projects, firm capacity, regional hydropower, transmission rights, interconnection positions, equipment, and development opportunities.
- Long infrastructure lead times require PGE to act early to prepare for the load of the future. Major transmission projects, interconnections, permitting, and emerging generation technologies can require development timelines of five to ten years or longer. Maintaining future options will necessitate commitments many years in advance of when the projects will be able to serve customers.
- Regional integration creates value. EDAM, evolving resource adequacy constructs, and new transmission development can expand access to regional resources and shared efficiencies. PGE must retain flexibility to participate in structures that provide customer value while maintaining sufficient resources to meet its own reliability obligations.
- The clean energy transition must remain adaptable. Oregon's statutory decarbonization requirements remain an important planning driver, while changes in federal policy, technology costs, resource availability, and customer affordability require flexibility in how PGE achieves continued emissions reductions.

PGE is planning for a period of significant change in the electric industry. Customer demand is growing at a pace not experienced in decades, regional energy and transmission surpluses are tightening, infrastructure development timelines are lengthening, and federal and state policies

affecting resource economics are evolving. At the same time, PGE must continue to provide safe, reliable and affordable electricity while continuing progress toward Oregon's clean energy objectives.

These conditions create both opportunity and uncertainty. Electrification and economic development can expand the customer base and support investment in Oregon, while new technologies, regional markets, and transmission can provide capabilities that were not available in prior planning cycles. However, competition for viable generation projects, transmission capacity, equipment, and development opportunities is increasing, and many of the investments necessary to serve customers require commitments years before they are needed.

The 2026 CEP/IRP therefore emphasizes flexibility, optionality, and timely execution. Rather than relying on a single forecast of the future, PGE's planning process articulates and evaluates a range of plausible conditions and prioritizes actions that perform well across multiple outcomes. This approach allows PGE to advance long-lead investments, when necessary, preserve access to scarce resources and infrastructure, and adapt the pace and composition of future investments as customer demand, technology, policy, and regional markets evolve.

These dynamics set the stage for the critical planning analysis questions and execution strategy decisions discussed in the rest of this plan. Ultimately, these trends highlight the need to approach challenges creatively and maintain a flexible approach to near-term actions.

3.1 Customer and Policy Expectations

Customers expect PGE to reliably power their homes, businesses, and communities at an affordable cost. Increasingly, they also rely on electricity to support transportation, heating, industrial activity, digital infrastructure, and economic growth. These expectations are occurring alongside Oregon's clean energy requirements and growing concern about the affordability of essential services.

PGE's planning must take all objectives into consideration and advance actions to reliably serve growing customer needs, manage affordability, advance clean energy requirements, and make investments that remain valuable across a range of future conditions.

3.1.1 Customer Affordability

PGE has served Oregon communities with reliable, affordable, and safe power for over 130 years, and that foundational responsibility remains unchanged. Because utility resource and infrastructure decisions influence customer prices for decades, affordability is a priority in how PGE plans, procures, and operates resources.

Customers, community representatives, and customer advocates have consistently emphasized the importance of centering affordability in utility decision-making. In PGE's recent rate cases, customer surveys, and community forums—including the CBIAG—commenters have highlighted the need to manage the pace and cost of the clean energy transition while maintaining reliability and advancing equitable outcomes. PGE customer survey results similarly indicate that affordability is a leading

customer priority, with 56% of respondents expressing that affordability should be PGE's highest priority (as depicted in Figure 17 of Section 1.4.1).

This focus on affordability has informed Oregon policy and regulatory priorities. HB 2021 established clean energy targets for investor-owned utilities while including a cost cap mechanism intended to help manage customer cost impacts. More recently, House Bill 3546 (passed in 2025), also known as the POWER Act, established cost allocation provisions for large-load energy users, including datacenters, to help costs associated with serving new large loads get assigned consistently with cost causation and that they do not create unreasonable cost shifts to other customers. PGE is working to incorporate both provisions within utility processes, as both mechanisms are refined through their respective regulatory processes.[36]

PGE prioritizes affordability across all aspects of corporate planning and operations. PGE's approach combines immediate assistance for customers facing financial hardship, including the Income Qualified Bill Discount Program and low-barrier Arrearage Management Plan, with long-term strategies that reduce the overall cost of servicing customers. PGE drives long-term downward pressure on rates through strategies evaluated in resource planning including cost-effective energy efficiency, scaling the VPP, utilization of Grid Enhancing Technologies, and continuing to maximize capture of federal tax credits.

As the planning landscape evolves, the topics discussed in this chapter, including federal tax-credit availability, tariff impacts, resource development, transmission and market evolution, wildfire risk, and ratemaking frameworks, all have implications for customer affordability. In IRP analysis, long-term costs are a primary metric within portfolio analysis (represented as NPVRR, described in Section 7.5.2). In addition, annualized costs are estimated and included in scoring results for all portfolios, providing additional insight into near-term cost impacts and trade-offs among resource pathways. In this IRP, PGE also introduced new calculations to estimate the impacts of costs on different customer classes (Section 7.4.2). Through assumptions and methodologies for high and low market price and technology cost futures, PGE's analysis investigates risks associated with each portfolio, as described in Section 6.6.3. Ultimately, PGE's comparison of GHG Glidepath, Continued Progress and Core Growth Only portfolios seek to explore trade-offs associated with affordability concerns (Section 1.4, Section 7.4.2), as well as consideration of HB 2021 affordability offramps in portfolio modeling assumptions (Appendix Section I.3).

Importantly, the CEP/IRP does not estimate rate impacts by customer class, as planning is uncertain and ratemaking requires known cost information rather than prospective assumptions. In accordance with OAR 860-090-0060(7), any cost estimates used or presented in the CEP/IRP should be used only for evaluation within the CEP/IRP context.

[36] AR 685 (Rulemaking on HB 2021 Cost Cap) and UE 473 (PGE 2027 GRC)

3.1.2 Increasing and More Uncertain Electric Demand

Electricity demand across PGE's service territory is increasing at a pace and scale not seen in decades. Industrial development, datacenters, transportation and building electrification, in the context of broader economic growth, all drive increased energy and capacity requirements.

PGE's service area has experienced significant industrial load growth in recent years, which is forecast to continue. From 2020 through 2025, PGE total load grew roughly 3%, largely supported by the 10% load growth from the industrial class in that period.

PGE executed load service contracts in 2025-2026 with five (5) customers representing 430 MW of load, while continuing to review 1.7 GW of additional incremental large load requests. PGE is planning for significant growth from large load customers in particular, driven by datacenter expansion and high-tech customers, with anticipated 10% annual growth between 2025 and 2030. However, the pace and magnitude of this growth are subject to considerable uncertainty, in part due to evolving local and state political dynamics, including a 120-day land use moratorium on new applications adopted by the City of Hillsboro,[37] the State of Oregon's termination of a proposed land sale for datacenter development,[38] and similar efforts under way in other jurisdictions.

Recent large load contracts, combined with the anticipated future industrial load growth, further bolster the importance of ensuring the costs of this growth are fairly allocated to the appropriate customer class. Following House Bill 3546, PGE secured regulatory approval to establish a new datacenter customer class, providing contracting flexibility and supporting residential and small business customer affordability.[39] The approved large load tariff creates regulatory clarity for continued growth of large loads, as well as a framework to encourage load flexibility and VPP integration.

In addition to large loads, system load growth drivers also continue to include projects for vehicle and stationary electrification. Electric vehicle adoption trends continue to be supported by state and local policies and are described in PGE's Transportation Electrification Plan (TEP). PGE's most recent TEP, filed in 2025, identifies pathways to enable transportation decarbonization while managing system impacts.[40] Building electrification is also expected to increase through the planning horizon, supported by policies including Oregon's Climate Protection Program (CPP).[41] Though the CPP, which imposes a gradually declining cap on emissions from fossil fuels, has been in place since 2024, ongoing legal challenges and redesign efforts contribute to uncertainty about the timing and magnitude of its impacts on PGE's load.

Load growth impacts and uncertainties are incorporated into the 2026 CEP/IRP through updated load forecast futures and scenario analysis. This analysis incorporates PGE's May 2026 load forecast, including high, reference, and low cases to allow comparison of resource needs and costs under

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[37] "Datacenters in Hillsboro: Next Steps After Moratorium." Posted 3 Aug 2026, accessed 11 Aug 2026. https://www.hillsboro-oregon.gov/Home/Components/News/News/17569/
[38] "Governor Kotek Directs State to Withdraw Land for Proposed Salem Datacenter Site." Posted 30 Jul 2026, accessed 11 Aug 2026. https://apps.oregon.gov/oregon-newsroom/OR/GOV/Posts/Post/governor-kotek-directs-state-to-withdraw-land-for-proposed-salem-data-center-site
[39] OPUC Docket No. UM 2377
[40] PGE 2025 TEP
[41] OAR Chapter 340, Division 271, Oregon Climate Protection Program.

different load trajectories (Sections 6.1.3). Similarly, portfolio analysis compares scenarios with all customer load to core load growth only (see Section 7.4.2). Since DER potential in certain cases expands as a function of load growth, the Core Load Only scenarios remove DSG potential assumed with large load growth. The Action Plan is designed to account for a range of potential future needs associated with load growth uncertainty, through its emphasis on flexibility over the planning horizon to track progress within calculated ranges. Together, these updates allow this analysis to assess resource needs, costs, and reliability outcomes under a range of plausible load growth futures using best available data.

3.1.3 Climate Policy and Expectations

Climate policy and customer expectations continue to shape the planning environment for electric utilities in Oregon and across the West. At the state level, Oregon has established a comprehensive clean energy framework, including the Renewable Portfolio Standard (RPS; SB 1547, passed in 2016) and HB 2021. Oregon's RPS requires electric utility to obtain increasing percentage of qualifying renewable resources for electricity provided to Oregon customers.[42] HB 2021[43] sets targets for emissions reductions for electricity sold to retail consumers in Oregon and a prohibition on siting or expanding natural gas generators in Oregon.

The Oregon Department of Environmental Quality (ODEQ) is tasked with collecting emissions data, establishing baseline emissions levels, calculating required reductions, and verifying projected emissions reductions, drawing on data submitted by electricity providers through Oregon's Greenhouse Gas Reporting Program. Together, the RPS and HB 2021 set the statutory expectation of a transition toward non-emitting resources while maintaining reliability and affordability. The urgency of these state policies has been emphasized by two (2) recent executive orders, EO 25-25 and EO 25-29 (Oct. 2025 and Nov. 2025). These orders direct state agencies to fast-track siting and permitting wind and solar projects and to take other actions aligned with the Oregon Energy Strategy.

Locally, city and county-level climate policies and initiatives also meaningfully impact PGE's resource planning. Many cities and counties served by PGE have published climate-related goals. PGE works closely with these local governments, including offering programs that enable decarbonization on an accelerated timeline (such as Green Future Enterprise and Green Future Impact) and support advancement of local clean energy projects (via Community-based renewable energy acquisition). Local programs like Portland Clean Energy Fund (PCEF) provide an additional avenue for supporting community-scale, equity-focused projects, aligned with local clean energy priorities. Continuing robust participation in Green Future Choice (residential customer base) and Green Future Impact (business customer base) programs, as well as consistent customer adoption rates of on-site solar and storage, indicate continuing customer demand for clean energy and in many cases, support for climate policy, among many of PGE's customers.

These state and local dynamics occur within a broader national context of uncertainty. Federal priorities have shifted since 2024 toward emphasis of energy dominance, energy independence,

[42] https://www.oregon.gov/energy/energy-oregon/pages/renewable-portfolio-standard.aspx
[43] https://www.oregon.gov/puc/utilities/pages/HB 2021-implementation-activities.aspx

and deregulation. Federal tax incentives for clean energy have been constrained or phased out, and some federal grant programs have been narrowed or refocused. Repeal of key provisions of the EPA's power plant rules, repeal of the EPA's 2009 Endangerment finding, and orders from DOE for specified thermal plants to remain online beyond scheduled closure dates are notable departures from the climate policy landscape applicable in PGE's previous planning cycle.[44]

Climate policy and customer expectations are directly incorporated into the 2026 CEP/IRP assumptions, modeling, and portfolio development, which includes resource assumptions and planning constraints that reflect applicable state policies. Consistent with HB 2021 and Renewable Portfolio Standard policies, modeled resource options do not include new construction of thermal generation development. In addition, the analysis framework is structured around policy-aligned scenarios and constraints, ensuring scenario analysis accounts for regulatory requirements. Further details on emissions assumptions, resource eligibility, and portfolio construction are summarized in Section 1.2.1 Reductions in Greenhouse Gas Emissions, Appendix G, and Appendix H respectively.

3.2 Resource Development Headwinds and Competition

The environment in which PGE acquires resources has changed significantly. Utilities are no longer competing only with other utilities for generation and capacity. Large energy users, developers, public power entities, and other market participants are competing for a limited pool of renewable projects, firm generation resources, transmission rights, interconnection positions, equipment, and development opportunities.

At the same time, federal tax changes, tariffs, supply-chain constraints, permitting delays, and transmission limitations are reducing the ability of proposed projects to advance through the development process and achieve commercial operation on the timelines customers require.

For PGE, these conditions change the relationship between planning and execution. Identifying a resource as least-cost and least-risk in an IRP does not ensure that the resource will remain available years later. Increasingly, preserving access to cost-effective resources requires earlier commercial decisions, development commitments, and regulatory alignment.

3.2.1 Federal Incentives and Resource Economics

Federal incentives are a key driver of resource economics and project availability in PGE's planning environment. When passed in 2022, the Inflation Reduction Act (IRA) provided a long-term extension and modernization of the Investment Tax Credit (ITC) and Production Tax Credit (PTC), which historically have faced repeated expirations and short-term renewals. The IRA also expanded credit availability with credit adders for domestic content, energy communities, and prevailing wage and apprenticeship requirements. The IRA also broadened eligibility across technologies, including standalone energy storage, and introduced credit transferability provisions, allowing project developers and utilities to monetize tax credits more efficiently.

[44] See for example U.S. Energy Information Administration, "Retirement delays of U.S. electric generating capacity may continue in 2026," Feb. 23, 2026. https://www.eia.gov/todayinenergy/detail.php?id=67206

More recent federal legislative developments have introduced changes to this policy landscape. The One Big Beautiful Bill Act (OBBBA, HR 1, passed in 2025) modifies and accelerates the phaseout of certain tax incentives, including the ITC and PTC, with distinct timelines depending on technology type.[45] Renewable generation resources and energy storage are subject to different sunset schedules, and emerging technologies may face additional uncertainty regarding eligibility and credit levels. At the same time, implementation of federal grant programs and other funding opportunities supporting clean energy development remains uncertain, with exposure to cancellations, additional requirements, and delays.

PGE is firmly committed to capturing federal tax incentives for the benefit of Oregonians. To date, PGE has secured over $1.4 billion of clean energy tax credits from the portfolio, and estimates as much as another $1.7 billion from long-term, third-party energy contracts. PGE has been awarded an additional $300 million in federal grants, though a portion of these awards (~$50 million) have been subject to recent federal award terminations. Maximizing access to these incentives remains a key consideration in resource planning and procurement decisions given the significant cost savings these credits provide. The removal of tax credits has the potential to increase costs 30% or higher for certain renewable projects, directly impacting customer affordability and PGE's pace of emissions reduction. In response to evolving federal timelines, PGE has taken steps to accelerate procurement schedules and prioritize projects with viable strategies to qualify for expiring tax credits, including through recent all-source RFPs and related contracting activities. In the 2025 RFP, all conforming projects, which offered in-service dates in 2028-2030, demonstrated strategies to establish eligibility for tax credits, primarily based on construction beginning prior to OBBBA deadlines. Though these projects may continue to experience risks, the risks are being actively managed by PGE and project developers. However, the 2025 RFP response and related market intelligence indicates a limited pool of tax-credit-eligible projects currently under development.

Federal tax policy assumptions are incorporated in proxy resource costs and portfolio analysis as impacts to the fixed costs of proxy new resources. Modeling assumptions reflect sunset schedules aligned with current tax policy, with additional analysis of implications of the expiration of credits (see Section 7.4.5). PGE's Reference case includes federal tax incentives as available only for wind and solar projects selected through PGE's 2025 RFP Final Shortlist (FSL), with no additional wind or solar projects assumed to qualify for ITC or PTC benefits beyond those procurements (Appendix Section G.7). Under the OBBBA, energy storage and eligible emerging technology (e.g., small modular nuclear reactor or enhanced geothermal) resources are not subject to this accelerated phaseout of federal tax credits –although tax credits for those resources do phasedown and phaseout across the second half of the 2030s. The Action Plan emphasizes the importance of acting expeditiously to capture remaining tax-credit-eligible projects, even if such projects may be found outside of 2025 RFP negotiations, in order to maximize important savings for PGE customers (see Section 2.3.1).

[45] One Big Beautiful Bill Act of 2025, Pub. L. No. 119-21, Title VII, Subtitle A.

3.2.2 Trade Policy, Supply Chains, and Long-Lead Equipment

Federal trade policy is an increasingly important driver of the cost and availability of energy and storage resources. Tariffs and import restrictions affecting solar, batteries, and related technologies have expanded in recent years, introducing greater uncertainty into project costs, supplier availability, and development timelines.

Tariffs on energy equipment reflect a layered and evolving policy framework, which continues to evolve amidst multiple judicial findings and administrative actions. Significant shares of solar and storage equipment are imported to the United States and are exposed to country-specific and technology-specific tariffs. At times since 2025, effective tariffs of 100% or more applicable to imports of solar components or modules have been proposed. Separate investigations under Section 2.3.2 for critical materials needed to develop battery storage and solar projects led to additional tariffs and import price control announcements, which are expected to strongly impact battery storage and solar development economics.[46]

Additionally, federal policies addressing supply chain security are affecting equipment costs and availability. Foreign Entity of Concern (FEOC) provisions limit access to tax credits and federal support for projects using components or suppliers linked to certain countries and introduce complex eligibility thresholds that may constrain available supply.

Meanwhile, concerns regarding cybersecurity risks associated with certain grid-connected equipment, including solar inverters and battery systems sourced from foreign manufacturers, could lead to additional technical requirements or future import restrictions. These risks are compounded by global supply chain concentration for key materials such as lithium, cobalt, and rare earth elements, increasing exposure to geopolitical disruption and trade policy changes.

Global load growth is also increasing pressure on supply chains, with near-term availability and cost impacts to many types of critical infrastructure. Main power transformer availability has been particularly impacted, with acquisition timelines for new orders extending to two (2) to five (5) years. Recent policy attention on increasing availability through new production capability could bring some relief, but details remain uncertain.[47] These dynamics directly impact resource development timelines and risks.

PGE addresses these dynamics through procurement strategies that emphasize supply chain transparency, compliance with evolving requirements, and contractual protections against cost escalation and delivery risk. In recent RFPs and negotiations, PGE has required counterparties to demonstrate viable approaches to managing tariff exposure and sourcing constraints. Continuation of these efforts will be important to the resource acquisition actions described in Chapter 2.

In planning analysis, these dynamics are reflected in aggregate assumptions for proxy resource cost and availability (see Appendix G). While tariff and supply chain risks primarily affect procurement execution, they contribute to resource pricing uncertainty as evaluated through low, reference and

[46] "Adjusting Imports of Polysilicon and its Derivatives into the United States." Posted 6 Aug 2026, accessed 12 Aug 2026. https://www.whitehouse.gov/presidential-actions/2026/08/adjusting-imports-of-polysilicon-and-its-derivatives-into-the-united-states/
[47] "Defense Production Act: Request for Information." Accessed 12 Aug 2026. https://www.energy.gov/cmei/manufacturing/defense-production-act-request-information

high technology cost futures (See Section 6.6.3). Project Development and Infrastructure Constraints

Availability of sufficient resource volumes, from customer-scale to utility-scale, is impacted by development challenges related to siting, permitting, interconnection and transmission factors. In addition to factors discussed in the previous two subsections, timelines and viability of large-scale projects are heavily dependent on interconnection and permitting timelines. Project development in the region is frequently dependent on BPA interconnection review timelines. BPA recently transitioned from serial studies to a first-ready, first-served cluster study, as part of a set of reforms intended to clear a queue backlog that had grown to 150 GW of project requests in 2024.[48] However, study completion, network-upgrade cost allocation, and construction timelines continue to place project development schedules and corresponding tax credit eligibility windows at risk.

Separately, Oregon land-use policy has limited the availability of Western Oregon farmland to renewable development, with siting projects on Eastern Oregon farmland growing more challenging as well. Permitting challenges have also arisen for storage and CBRE projects in certain jurisdictions; for example, the City of Hillsboro adopted a temporary moratorium on permitting energy storage facilities.[49] Development timelines for many Oregon-sited projects must account for required Energy Facility Siting Council (EFSC) reviews. Future projects may benefit from recent state policy attention on the permitting process, including HB 3681 (2025), which implemented changes to streamline EFSC review process and Governor Kotek's Executive Order 25-29, which established binding timelines and measurable targets across state agencies.

Federal permitting processes, including National Environmental Policy Act (NEPA) review, also impact many projects' development timelines, with current increased uncertainty tied to changes to the review process. While many reviews including NEPA apply to projects whose generation facilities or interconnection infrastructure is sited on federal land, a new challenge emerged in 2026 regarding required evaluations by the Federal Aviation Administration (FAA) of all wind project applications. In the absence of action by the Defense Department, new onshore wind projects with pending certifications—including projects on PGE's 2025 RFP final shortlist—are unable to start construction. Legal challenges are ongoing as of summer 2026, imposing continuing uncertainty on development timelines and viability.[50]

PGE's focus on project development viability in RFP bid evaluation seeks to screen projects for the interconnection and permitting risks described here, in addition to other development risks. Even so, PGE has identified the need for additional flexibility in 2025 RFP negotiations and continuing procurement efforts to balance the potential impacts of these risks on customers. These issues are not represented directly in portfolio modeling beyond their effect on the quantity and timing of near-term proxy resources assumed to be commercially available. They are, however, important considerations in the Action Plan, where future procurement actions increasingly need to prioritize project viability—including permitting status, land-use risk, interconnection readiness, and

[48] See https://www.bpa.gov/energy-and-services/rate-and-tariff-proceedings/tc-25-tariff-proceeding
[49] https://www.hillsboro-oregon.gov/Home/Components/News/News/17551/4300
[50] Renewable Northwest et al. v. Hegseth, No. 3:26-cv-01092-IM, Opinion and Order (D. Or. Aug. 6, 2026), Dkt. 125.

development timing—alongside the traditional considerations of cost and performance (see Section 2.2.4).

3.2.3 Competition with Utilities and Large Customers for Viable Projects

The competitive landscape for energy procurement has expanded significantly in recent years. Robust demand from traditional utility buyers seeking to meet growing load are now exposed to new competition from large non-utility consumers. These entities, generally linked to new large loads, can make large financial commitments, are able to accept higher levels of development and commercial risk, and can move quickly to secure projects, which contributes to increased competition for a limited pool of near-term resource opportunities. PGE has observed these dynamics directly in recent procurement cycles. For example, in both the 2023 RFP and 2025 RFP, renewable projects included on initial and final shortlists were acquired by non-utility buyers prior to entering into negotiations with PGE, resulting in loss of over 1,000 MW of wind, solar and storage resources. Similarly, renegotiation of existing PGE contracts exposes PGE to competition from new buyers.

In addition to contributing to increased load forecasts as discussed in Section 3.1.3, state and local climate policies outside of Oregon contribute to strong regional demand for renewable projects. Most states in the region, including Oregon, continue to have varying forms of RPS or other similar clean energy standards in place. In addition, California's Cap and Trade, Washington's Climate Commitment Act, as well as more targeted policies to reduce reliance on coal imports, all factor into regional utility buyers' high renewable procurement targets.

These developments underscore the need to adapt procurement processes to expediently capture viable projects that are exposed to competition, and to prioritize where appropriate projects with reduced procurement competition. From a planning perspective, increased procurement competition contributes to both the scarcity and cost of modeled resource options. These dynamics are reflected in the quantity, timing, and price assumptions for proxy resources. Informed by PGE's 2025 RFP Final Shortlist filing, modeling only assumes availability of approximately half of PGE's 2025 RFP final shortlist volume, reflecting the viability challenges described above and competition for projects with competitors (Appendix Section G.5). These market dynamics are also contributing factors to PGE's Action Plan, which emphasizes the importance of acting nimbly when viable opportunities arise (as discussed in particular in Section 2.3.1). In an increasingly competitive environment, streamlined processes to reduce risk in commercial decisions are critical to securing cost-effective resources on behalf of customers.

3.2.4 Direct Access and Resource Adequacy Responsibility

Oregon's Direct Access (DA) framework reflects a long-standing policy that promotes retail competition. At the same time, the DA program is designed to ensure that customers leaving the utility do not cause unwarranted shifting of costs to other utility customers. Established under Senate Bill 1149 (1999), DA allows eligible nonresidential customers to procure electricity from certified Electricity Service Suppliers (ESSs), while utilities continue to provide delivery service and remain the provider of last resort. Accounting for 9% of PGE's net system load in 2025, ESSs represent an additional source of demand for a limited pool of resources, influencing market availability and pricing for capacity and energy products as discussed above.

Over time, the Commission has structured direct access programs—including long-term direct access (LTDA) and new load direct access—through eligibility criteria, participation caps, and transition mechanisms intended to mitigate cost shifting to cost of service customers. In May 2026, the OPUC revised aspects of the DA framework and reaffirmed that program design must prevent cross-subsidization between customers taking utility service and those electing competitive supply.[51] The Commission clearly stated that the DA business model must be reliable and incorporate the full cost of resource adequacy (RA). However, during a temporary three-year period, ESSs may use a new utility RA backstop product, with costs set to avoid cost shifting based on avoided costs. This Capacity Backstop Charge (CBC) mechanism will allow eligible existing, non-curtailable direct access customers to be included in PGE's RA load through October 1, 2029. This outcome provides PGE with a mechanism to plan and procure for participating direct access load while requiring ESSs to pay the full associated capacity and transmission costs, thereby protecting cost-of-service customers from cost shifting

ESSs will ultimately be responsible for demonstrating both the resource adequacy and environmental performance of the electricity they supply to DA customers. OPUC rules updated in 2024 require ESSs to demonstrate capacity sufficiency on a planning basis through participation in a regional RA program, with informational showings submitted to the Commission.[52] Meanwhile, HB 2021 establishes clean energy continual progress compliance expectations to ESSs for DA, with the OPUC directing ESS providers to file their first Emissions Compliance Reports on January 1, 2027.

The 2026 CEP/IRP therefore treats resource adequacy not simply as a PGE procurement requirement, but as a broader market-design consideration. PGE will continue to maintain sufficient resources to reliably serve its customers while supporting regulatory and regional frameworks that appropriately assign reliability obligations and costs to all load serving entities. See Section 6.1 on PGE's load forecast process, with additional detail in Appendix Section H.8. See description of reliability analysis in Section 7.11.

[51] OPUC Order No. 26-153, Docket No. UM 2024
[52] OAR 860-095-0030

3.3 Regional Reliability Outlook

PGE's planning is closely linked to planning dynamics affecting the Northwest and West more generally. Across the region, the impacts of forecast load growth and generation buildout impact PGE's assessment of reliability drivers examined in long-term planning.

3.3.1 WECC-Wide Load Growth

Load growth across the Western Interconnection is accelerating, driven by similar forces to those described in Section 3.1.2. The Western Electricity Coordinating Council (WECC) reported record annual demand and record peak demand in 2025 and forecasts a 33% increase in total loads over the coming decade.[53] WECC's 2025 resource adequacy assessment found planned resource additions may not keep pace with anticipated load growth and identified potential energy shortfalls as early as 2028 if planned projects are delayed or canceled.[54] Much of this anticipated growth is from hyperscale datacenters proposed in Utah and other Western states.

These regional trends further increase competition for generation, capacity, and transmission and impact the availability and costs of market energy purchases. To reflect these and other factors in resource planning, PGE produces a range of wholesale energy price curves using a model of supply and demand across the Western Interconnection. This model is informed by data provided by Wood Mackenzie, an external consultant (Section 6.6.2). In addition, very limited resource availability from neighboring utilities during constrained periods is assumed in portfolio analysis, reflecting tighter regional conditions (Appendix Section H.5.4).

3.3.2 Renewable Adoption Trend

Across the WECC, wind, solar, and battery storage have become the dominant forms of new resource development. WECC reported that more than 18 GW of new generation capacity was added in 2025, of which 15 GW was inverter-based solar, battery storage, and wind.[55] WECC also reports that 90% of planned resource additions in the West over the next decade are battery storage, solar, or wind.[56] The prevalence of these technologies is driven by their continued cost-competitiveness, despite the headwinds described above. Lazard's 2025 Levelized Cost of Energy+ (LCOE+) analysis found that utility-scale solar and onshore wind remain the lowest-cost forms of new-build generation even on an unsubsidized basis and characterized these resources as likely to continue playing a key role in new U.S. power supply because they are both cost-competitive and relatively quick to deploy.[57]

As more wind, solar, and storage resources are added, marginal capacity contributions decline. Western Resource Adequacy Program's (WRAP) winter and summer Effective Load Carrying Capability (ELCC) / Quality of Capacity Contribution (QCC) data show this effect directly, with qualifying capacity values falling as GW-scale adoption increases in several zones and resource

[53] https://feature.wecc.org/soti2026/state-of-the-interconnection-2026/load/index.html
[54] https://feature.wecc.org/2025wara/index.html
[55] https://feature.wecc.org/soti2025/soti2025/resources/
[56] https://feature.wecc.org/2025wara/index.html
[57] https://www.lazard.com/news-announcements/lazard-releases-2025-levelized-cost-of-energyplus-report-pr/

classes.[58] This creates a discontinuity between the accelerating adoption of VERs described above and their alignment with reliability needs, increasing the importance of other resources, transmission, and operational strategies.

PGE reflects these dynamics in multiple parts of the CEP/IRP. PGE incorporates WECC-wide renewable adoption trends into market price forecasts and associated sensitivities (Appendix Section H.2.1). The ELCC analysis assesses the changing capacity value to PGE's system of wind, solar, and storage as adoption rises (Appendix Section H.5). These dynamics inform portfolio results and the Action Plan, informing RFP valuation and prioritization strategies for prospective resources (Chapter 1 and Chapter 7).

3.3.3 Pacific Northwest Reliability Landscape

External studies suggest the greater Pacific Northwest is facing growing reliability concerns [59, 60, 61, 62] These studies highlight the resource adequacy risks caused by regional retirement of dispatchable capacity, load growth, and constrained transmission networks. A recent assessment of resource adequacy in the Pacific Northwest by Energy + Environmental Economics (E3) estimates that by 2030, the region will have a 9 GW gap in effective capacity needed to maintain reliability.[63] E3's analysis shows the pace of annual resource additions required to fill the reliability gap is four to five times greater than the annual average achieved in the region since 2000. Further, forecasted reliability challenges are concentrated in Winter, as multi-day cold-weather events strain an energy limited system. A primary conclusion from E3's report suggests natural gas peaking capacity is a robust long-term strategy to maintain reliability while achieving deep decarbonization. E3's findings were subsequently evaluated by Sylvan Energy Analytics, corroborating the winter reliability concern. This highlights a need for short-term demand-side strategies and emphasizes that "the need for dispatchable or baseload solutions is not a question of if, but when."[64]

Reliability concerns are more acute West of the Cascades where load is concentrated, and transmission constraints inhibit access to generating resources. Such is the case for PGE, whose growing loads necessitate transmission expansion to access non-emitting generation resources with high-capacity factors. Efforts are underway to develop capacity programs featuring RA obligations and reporting for all load-serving entities including ESSs serving direct access customers (Section 3.4.4).

These findings are incorporated into long-term planning through explicit winter stress modeling and portfolio needs assessment (Section 7.11). In particular, the CEP/IRP evaluates resource performance under prolonged constrained conditions and reflects the implications of such events

[58] Summer 2027: https://www.westernpowerpool.org/private-media/documents/2025-12-10_WRAP_Summer_2027_and_2030_Data_BOD.pdf
[59] NERC, 2026 State of Reliability report, 2026, https://www.nerc.com/newsroom/2026-State-of-Reliability-Report.
[60] NWPCC, Pacific Northwest Power Supply Adequacy Assessment for 2029, 2024, https://www.nwcouncil.org/fs/18853/2024-4.pdf.
[61] ODOE, Oregon Energy Strategy, 2025, https://www.oregon.gov/energy/data-and-reports/Documents/Oregon-Energy-Strategy.pdf.
[62] PNUCC, Northwest Regional Forecast, 2026, https://www.pnucc.org/wp-content/uploads/2026-PNUCC-Northwest-Regional-Forecast-4-21-26-final.pdf.
[63] E3 NW RA Final Report. Document is not yet public, awaiting final publication Spring 2026.
[64] Near-term winter resource adequacy challenges in the Pacific Northwest. Sylvan Energy Analytics. January, 2026.

for the value of firm capacity, storage duration, market access, and flexible customer resources (methodology details in Appendix Section H.5). This planning cycle also gives increased attention to opportunities for load flexibility, including updates to VPP assumptions tied to large-load growth scenarios (Appendix Section G.2).

3.3.4 Emerging Technology Progress

Emerging clean technologies, such as small modular nuclear, advanced geothermal, carbon capture and sequestration, and long-duration storage, have the potential to play an important role in providing firm, dispatchable, non-emitting energy, helping to address these reliability dynamics. Despite continuing research and development support, in the absence of broad market adoption, these technologies continue to experience uncertainty related to cost, development timelines, supply chains, permitting, and operational performance at scale.

Recent announcements by large technology companies illustrate both the potential and the uncertainty of this space. Microsoft, Google, Amazon, and Meta have each announced major nuclear-related activities, providing significant financial support to commercialization efforts.[65] However, the details of the announcements underscore the uncertainty, with timelines extending into the 2030s. Enhanced geothermal facilities and long-duration storage show similar promise: market and investment activity have increased, and recent reports point to improved viability and project pipelines.

For PGE, emerging technology availability remains a key planning uncertainty. Emerging technology is represented in planning analysis as a single proxy resource type capable of providing non-emitting capacity and energy, as described in Appendix Section G.5.5 and challenges of emerging technology consideration are incorporated in portfolio analysis and PGE's long-term resource strategy (Section 7.6 and Section 1.5.1, respectively).

3.3.5 Gas and Electric Transmission Utilization

Existing electric and natural gas infrastructure is being used more intensively as regional loads increase, resource development in renewable-rich regions continues, and energy imports and exports from California influence regional markets. Analysis from Stanford University found that the Northwest's transmission lines had the fourth-highest utilization in the Western Interconnection out of 24 control areas during summer peak contingency conditions, with similar results for transformer loadings.[66] Competition for use of limited existing transmission is also evidenced by BPA's increasing use of conditional firm transmission products leading to a broader effort to overhaul its

[65] For example, see MIT Technology Review article, 20 May 2025, accessed 13 Aug 2026. https://www.technologyreview.com/2025/05/20/1116339/ai-nuclear-power-energy-reactors/
[66] Measured under N-1 contingency criterion. https://www.nwcouncil.org/news/2026/03/27/westtec-study-results-pacific-northwest-transmission-system-expansion/

transmission service queue and study process.[67] As of summer 2026, BPA's planning reforms are still in progress, with uncertain implications for transmission availability to new resources.

Similarly, access to existing natural gas transmission infrastructure for electric generation is increasingly limited. In a presentation to Washington regulators, NW Natural warned that pipeline systems in the Pacific Northwest are very constrained, increasing risks of volatile market prices.[68] Constraints for both electric and natural gas systems are particularly important during winter stress periods, when regional buyers may have limited ability to acquire additional transmission or imports.

Compared to previous analysis, the 2026 CEP/IRP includes more details regarding current BPA transmission availability. Proxy resources now have access to a combination of firm, conditional firm, and non-firm transmission assumptions that vary based on location informed by PGE market intelligence (Appendix Section H.6.6). PGE has also embedded assumptions in dispatch simulations, limiting thermal dispatch ability informed by real natural gas delivery constraints to select thermal (See Appendix Section H.5.7).

3.4 Regional Market and Transmission Development

Regional market design and transmission development are increasingly important features of the planning environment because they affect both the availability of resources and the ability to deliver resources to load. As conditions tighten across the West, PGE's planning must account not only for what resources may exist but also for how emerging market structures and resource adequacy frameworks, as well as evolving transmission networks, affect access, reliability, and timing.

PGE's transmission system is highly integrated with other transmission systems in the West, due in large part to BPA's historical role in building and operating a regional transmission system. Because PGE's network load is centralized in a compact service area, instead of spread across a larger geographical area, PGE utilizes a concentric circle model to plan available transmission options, described in (Section 5.1).

3.4.1 Day Ahead Market Expansion

The West is shifting from balancing area-level operations to broader regional market structures. Over the past decade, the sub-hourly Western Energy Imbalance Market (WEIM) grew to cover more than 80% of West-wide load, with PGE joining in 2017. CAISO's Extended Day-Ahead Market (EDAM) builds on that real-time framework by expanding to the day-ahead timeframe, when most generation and transmission commitments are made. EDAM went live on May 1, 2026, with PacifiCorp as the first participant, and PGE joined on October 1, 2026. After comparative analysis, PGE selected EDAM as its preferred day-ahead market choice to maximize economic efficiencies and reliability benefits for PGE's customers, with anticipated gross cost savings between $6 million and $18 million annually.[69] EDAM provides direct connectivity to a market footprint that

[67] https://www.bpa.gov/energy-and-services/transmission/transmission-planning-reform
[68] https://www.utc.wa.gov/sites/default/files/2025-11/NW%20Natural%20Winter%20Readiness%20Slides.pdf
[69] https://investors.portlandgeneral.com/news-releases/news-release-details/portland-general-electric-announces-intent-join-caiso-edam

contains diverse generation sources, enhancing PGE's ability to access low-cost, renewable energy. Multiple utilities, who are estimated to serve over 50% of the load in the Western Interconnection have committed to EDAM.

In parallel, Southwest Power Pool (SPP) has launched RTO West in the intermountain region and is offering Markets+ as an alternative day-ahead market in the West. Markets + has attracted many interested parties through the Phase One and Phase Two developments, including BPA and Puget Sound Energy. PGE is actively engaged with BPA, CAISO and other stakeholders to assess and develop mitigations for impacts of the EDAM and Markets+ transition on utility planning and operations.

The shift from an imbalance market to a day ahead market affects PGE on both an operational and planning basis. Operationally, EDAM expands regional coordination into the day-ahead timeframe by optimizing generation, load, and transmission commitments, while continuing sub-hourly balancing through WEIM. In PGE's energy price forecasts and market dispatch simulations, the Western Interconnection is modeled as an interconnected system with physical transmission limits governing the exchange of energy throughout the system. When assessing portfolio resource adequacy sufficiency, PGE assumes limited availability of energy from markets (Appendix Section H.5.4). These market changes may add to uncertainty regarding future transmission availability as discussed in Chapter 5, increasing the importance of long-term firm transmission rights as regional organized markets diverge.

Changes to organized markets and PGE participation in them will also support PGE's access to greater amounts of clean energy. Current Oregon emission reporting regulations do not account for evolving market resource mixes in the region. As such, these regulations currently limit Oregon utilities options to leverage the benefits of regional diversification in the market while delivering reliable power and complying with statutory clean energy targets, like HB 2021. PGE explores a planning scenario in Appendix Section I.5 to assess what a replacement Western market emission factor could look like in the future based in model data as various state clean energy policies advance.

3.4.2 BPA Transmission System Investment

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 rights under contract with BPA. PGE's ability to interconnect resources to and flow increasing amounts of power through BPA's system is largely dependent on BPA's efforts to expand transmission infrastructure, award transmission rights, manage local congestion, and complete interconnection studies.

Because BPA is a self-funded federal power marketing administration within the U.S. Department of Energy, it is not subject to FERC jurisdiction, and it can be directly impacted by federal policy and workforce actions. During 2025, BPA experienced employee attrition and a hiring freeze, prompting concern from Northwest lawmakers; by May 2025, BPA stated that no further staffing reductions were planned. In 2026, BPA's new leadership emphasized the reputation and importance of BPA's

work force and reiterated support for BPA's grid expansion projects and transmission planning reform.[70]

Schedules for approved transmission upgrade projects impact development of new generation resources. BPA has sought to increase its transmission capabilities through the Grid Expansion and Reinforcement Portfolio (GERP, formerly known as the Evolving Grid Initiative). In 2023 and 2024, BPA announced more than 20 transmission line and substation projects with estimated costs of more than $5 billion.[71] While GERP Phase 1.0 projects are progressing through construction, in some cases with timeline delays, Phase 2.0 projects remain in pre-construction status, with in-service dates largely scheduled for 2031-2035.

Meanwhile, California has added more than 30 GW of new resources since 2020, primarily solar and storage, that have fundamentally reshaped how power flows across the west.[72] These new south-to-north flows have exposed PGE to new system risks, specifically, BPA's creation of the North of Pearl (NOPE) flow gate in 2023. NOPE changed how congestion is observed and managed in the Portland area, emerging as a reliability constraint for PGE. NOPE congestion management has negatively impacted PGE's ability to use its transmission portfolio to deliver power to customers, especially during periods of surplus California solar and storage imports into the Northwest.

BPA's commercial planning processes are also in transition. After BPA's transmission service queue grew to 65 GW of unstudied requests, BPA cancelled its 2025 transmission service cluster study and portions of related planning processes to reevaluate its framework. BPA's Grid Access Transformation (GAT) initiative is intended to revise long-term firm queue management, interim service, and commercial planning processes, but timing of outcomes from this process remain unclear.[73] In the interim, BPA is attempting to process or remove as much of the 65 GW queue as possible before GAT is implemented.[74] Within the GAT initiative, BPA is considering reforms that would grant conditional firm transmission service (CFS) to certain requests prior to completion of enabling grid expansion projects.[75] CFS transmission flows have a lower priority than long-term firm transmission (LTF), limiting usefulness for system reliability, especially in the context of EDAM/Markets+ seams. Increased use of CFS is also likely to negatively impact availability of lower priority transmission products (e.g. short-term firm and non-firm).

Even after commercial studies resume under GAT, new transmission service plans with delivery to PGE are likely to be conditional until completion of GERP projects and other identified physical upgrade plans of service. BPA's increasing use of CFS further entrenches the value of LTF in PGE's

[70] https://www.bpa.gov/about/newsroom/news-articles/20260629-kavulla-sworn-in-as-17th-bpa-administrator
[71] https://www.bpa.gov/energy-and-services/transmission/grid-expansion-and-reinforcement-portfolio
[72] www.caiso.com/documents/2026-summer-loads-and-resources-assessment.pdf
[73] https://www.bpa.gov/energy-and-services/transmission/grid-access-transformation-project
[74] BPA TC-27 proceeding
[75] BPA's GAT initiative describes plans to offer more Conditional Firm Service than previously made available, which makes forecasts based on historical patterns less reliable. The first "wave" of Conditional Firm Service offers under GAT changes are expected shortly following the conclusion of BPA's TC-27 process (Fall 2026).

resource planning and increases financial risks to project owners and utility customers dependent on CFS, transmission redirects, or other transmission strategies,

To represent uncertainty of BPA transmission availability, PGE's planning models incorporate detailed assumptions for transmission access on BPA's system (Appendix on ROSE-E assumptions). Proxy resources are evaluated using differentiated assumptions that reflect expected transmission availability by transmission product type, considering location-specific details and transmission path characteristics. (Appendix on resource options). All scenarios also assume completion of BPA's current GERP as part of the base case transmission outlook (Section 5.2.2). These assumptions make transmission deliverability a more explicit part of resource valuation and portfolio feasibility than in previous planning cycles. However, IRP analysis does not directly analyze BPA timeline and operational uncertainties, which are a point of connection to PGE's near-term action plan and project-specific procurement evaluation.

3.4.3 Regional Transmission Planning Coordination

Regional transmission projects are gaining momentum across the West, but the planning environment remains defined by long development timelines, evolving institutional processes, and uncertainty regarding who will move projects from study to construction. Throughout the region, NorthernGrid remains the principal regional planning forum for many transmission owners, including PGE, under FERC Order Nos. 890, 1000 and 1920.

Additionally, WestTEC, a broader West-wide collaborative, was launched in late 2023 to address broader interregional planning gaps across the Western Interconnection and develop actionable 10- and 20-year transmission studies.[76] WestTEC's February 2026 10-Year Horizon Report identified a portfolio of projects adding or upgrading more than 12,600 miles of high-voltage transmission at an estimated cost of approximately $60 billion by 2035. WestTEC is a voluntary and informational process rather than a project approval mechanism, but it reflects a broad regional view that existing planning frameworks have not kept pace with rising load, new resource development, and the changing grid conditions in the region. WestTEC's study results inspired the initiation of a state-led forum focused on expedited transmission permitting in the West.[77]

At the same time, transmission development is being advanced through utility-driven processes. These efforts are being advanced through the efforts of the Western Transmission Consortium (of which PGE is a participant) among other entities. Transmission project developments demonstrate growing momentum, but face headwinds from very long lead times tied to permitting, land acquisition and financing. As just one example, the Boardman-Hemingway line, which is under construction with energization scheduled for 2027, filed its initial federal permitting application in 2010.

Accordingly, federal policy and funding have become increasingly important to transmission development. While transmission expansion has received federal policy support through borrowing

[76] https://www.westernpowerpool.org/news/westtec-a-new-approach-to-transmission-planning-in
[77] In July 2026, a group of 11 bipartisan governors endorsed WestTEC's study and announced the creation of the Permitting Alignment and Coordination Task Force. https://www.westernpowerpool.org/news/western-governors-endorse-westtec-create-permittin

authority, DOE financing tools, and grant programs intended to accelerate siting, permitting, and project development, federal programs, and priorities are in flux, as discussed in Section 3.2.1.

PGE has been a leader in promoting regional transmission planning coordination, advancing projects capable of providing customer benefits, and leveraging federal grant funding opportunities for the benefit of Oregonians. In 2023, the Confederated Tribes of Warm Springs (CTWS) and PGE were an awardee of a U.S. Department of Energy Grid Resilience and Innovation Partnerships (DOE GRIP) grant for the Warm Springs Power Pathway transmission corridor.

Portfolio analysis in this planning cycle incorporates a new evaluation method that makes 10 proxy transmission lines available to be selected, informed by the cost-optimization of the capacity expansion model. Creation of proxy assumptions for discrete transmission lines allows planning models to build portfolios that can choose to build transmission to access additional regional resources, while factoring transmission cost trade-offs into optimization calculations (see Chapter 5).

3.4.4 Resource Adequacy Program Landscape

Regional frameworks for resource adequacy continue to evolve as the West moves away from utility-by-utility planning assumptions and toward more integrated markets and common approaches to reliability. In 2024, OPUC adopted Division 95 Resource Adequacy rules, which require utilities and electricity service suppliers to participate in Commission-approved regional reliability planning. The Commission has recognized the need for flexibility during the transition, including waivers tied to early state program compliance while regional program options continue to evolve.

The Western Resource Adequacy Program (WRAP) is currently the most developed regional effort, establishing a framework for common planning reserve requirements, binding forward showings, and Qualifying Capacity Contributions (QCCs) for different resource types, under a FERC-approved tariff. Details of the program scope remain in development, as complications of a program in which members may be participating in different emerging regional markets (that is, EDAM and SPP's Markets+). In 2025, PGE chose not to participate in binding program operations but continues to participate in the non-binding phase through fall of 2027.

In parallel, PGE and a group of other EDAM-participating Western utilities have undertaken construction of a new, voluntary RA compliance program.[78] The new program emphasizes the benefits arising from alignment of market and RA frameworks and the connectivity and diversity of the EDAM footprint to reduce policy conflicts, support consistent incentives and utilize market dispatch for RA resource delivery. The EDAM-aligned RA program design elements and compliance framework are being developed throughout 2026, with implementation timing to be specified.

These evolving regional dynamics are reflected in the 2026 IRP through a dedicated State Reliability Metrics Portfolio that applies WRAP based needs assessment and capacity accreditation measures,

[78] EDAM-aligned RA program background documents and workshop materials are posted on the Regional Organization for Western Energy (ROWE): Regional Resource Adequacy Program | ROWE Western Energy

allowing resource buildout outcomes to be evaluated under an existing regional reliability framework (Section 7.4.6).

3.5 Other Regulatory and Market Dynamics Impacting Planning

While largely outside the scope of IRP analytical methods, PGE's success in advancing the energy transition as contemplated by the Clean Energy Plan and Action Plan is strongly dependent on supportive regulatory structures and partnerships.

3.5.1 Wildfire Risk

PGE and long-term suppliers face significant capital investments to construct and commission the portfolio of resource additions contemplated in PGE's resource plan. Wildfire risk continues to grow in Oregon, threatening the safety of the communities served, as well as utility assets and the overall financial health of the utility.

PGE's ability to maintain investment-grade credit ratings is critical in supporting both PGE's priority of procuring renewable resources at the lowest possible cost and investing in wildfire mitigation actions that help protect PGE's customers, communities and utility assets. PGE's Wildfire Mitigation Plan calls for substantial spending on undergrounding lines, vegetation management, AI-enabled cameras, weather stations and grid hardening. Unresolved exposure to wildfire risk can negatively impact credit ratings, directly resulting in higher capital costs. Higher capital costs drive up the costs of clean energy projects, burdening PGE' ability to decarbonize while balancing affordability. Further, 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 and policy action to address unbounded utility wildfire liability risk is needed at the state and/or federal level. Despite successfully implementing 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. PGE continues to assign the highest priority to wildfire mitigation actions, as featured most recently in PGE's 2026-2028 Wildfire Mitigation Plan, which was approved by OPUC in 2026. However, wildfires are inherently uncertain, making liability reform a critical enabler of utility clean energy actions.

3.5.2 Holding Company Structure

To continue serving customers reliably while making significant progress toward decarbonization, PGE will need a diverse mix of generation and transmission resources. This will include a range of commercial structures, including PGE-owned assets and resources secured through long-term power purchase agreements. Both approaches are essential to meeting evolving customer demand, maintaining reliability, advancing clean energy, and managing costs.

This is why PGE has continued to advocate for a holding company that aligns with common utility structures. This type of structure would give PGE more financing options and help PGE pursue the capital needed for customer investments at the lowest reasonable cost. The lower the cost of financing, the less customers ultimately pay. PGE's ability to achieve the actions identified in this

plan are subject to risk if PGE is unable to obtain the financing necessary to support these projects on favorable terms.

3.5.3 Workforce Availability

The pace at which PGE can advance its clean energy goals is directly tied to the availability of qualified workers. Without a sufficient workforce pipeline, the ability to site, build, and connect new clean energy resources at the speed Oregon's climate goals require will be constrained, making workforce development a critical enabler of the clean energy transition. PGE took a proactive step in 2022 by establishing the Oregon Clean Energy Workforce Coalition (OCEWC). Since its launch, the coalition has grown to include more than 100 partners spanning industry, labor, government, employers, educational institutions, nonprofits, and community-based organizations, all united around the goal of building a stronger talent pipeline for Oregon's clean energy future.

The OCEWC has made significant strides since its founding. The coalition has secured nearly $4 million in funding from the U.S. Department of Labor and private funding. Their work was recognized as one of only six national awardees in the Regional Green Jobs Challenge with Jobs for the Future, a national workforce development nonprofit. These resources are being deployed in meaningful ways, including training adults in custody for direct entry into union apprenticeship programs upon release and creating pathways to stable employment across the state.

The coalition continues to advance actions to secure Oregon's clean energy workforce pipeline, connecting people to family-wage careers and ensuring that employers have access to the skills and talent needed to drive the clean energy transition forward.

3.5.4 Regulated Ratemaking Frameworks

Regulated utility cost recovery of prudently incurred generation, power, program, and asset costs occur through a set of OPUC processes including rate review proceedings, power cost updates and adjustments (AUT and PCAM), and program-specific approvals, deferrals, and pass-throughs. These regulatory mechanisms serve as an additional dimension of PGE's planning environment, as the pace and magnitude of PGE commitments to generation and transmission development are strongly influenced by regulatory risk.

To support the necessary scale and pace of resource development, existing ratemaking and procurement frameworks must evolve to address impacts of market integration, unique challenges of long-lead infrastructure, and the increasingly dynamic resource procurement landscape. Section 1.5.1.4 describes key reform priorities.

4 Modeling and Process Overview

This chapter provides a high-level overview of the analytical process that PGE utilizes in resource planning, including overviews of PGE's tools and the modeling approach. Supporting details on modeling tools and processes are provided in Appendix H IRP Modeling Details.

Chapter Highlights

- PGE's resource planning process tests resource options under a broad range of possible futures. PGE's analysis continues to be comprised of three (3) core exercises: production cost simulation, resource adequacy, and capacity expansion.
- PGE has made significant updates to planning analysis methods since the 2023 IRP cycle. These updates include hourly emissions forecasts, comprehensive transmission expansion and alternative analysis, inclusion of increased market integration benefits, and a more rigorous analysis of portfolio risks.

PGE's 2026 CEP/IRP is comprehensive exercise in modeling the power system of the future. Using the best available data and understanding of the planning environment, the CEP/IRP uses a host of technical tools to forecast PGE's system needs, evaluate resource options, and develop a plan for a least-cost, least-risk resource investment strategy. As discussed in Chapter 3, the 2026 CEP/IRP is facing a complex planning environment presenting many uncertainties. The CEP/IRP attempts to capture these uncertainties by quantitatively modeling various pathways to maintain a reliable and affordable system while progressing on emissions reduction requirements. This IRP and all related forecast analyses should be read as directionally informative but inherently cannot fully represent operational practices nor the future as certain. The resource planning process is meant to provide a roadmap that helps PGE deliver on its commitment to serve customers with reliable, affordable, and increasingly clean energy.

4.1 Analytical Process Overview

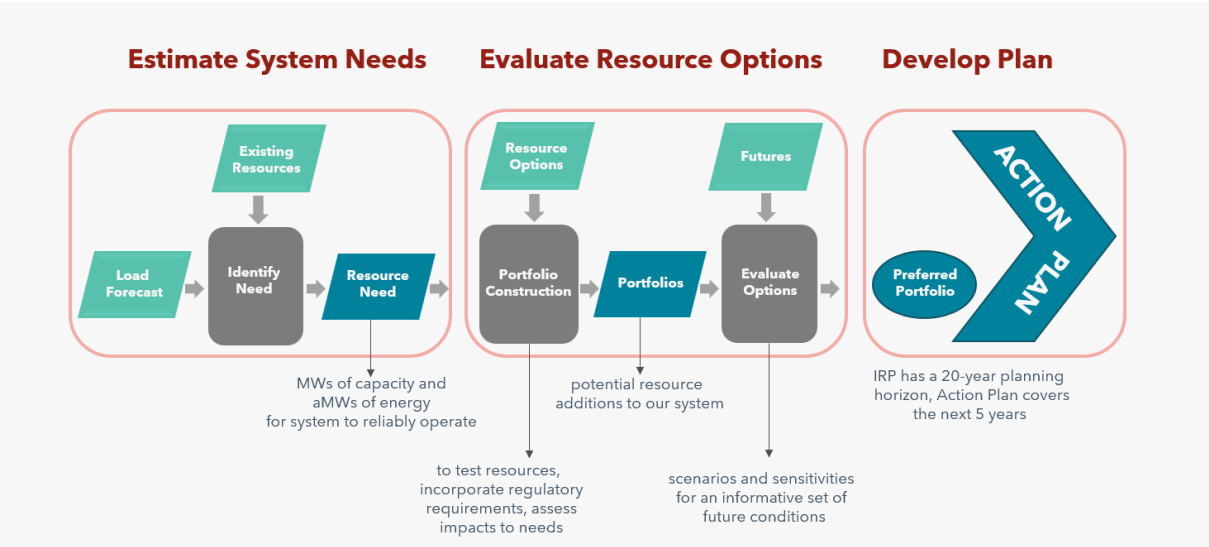
PGE's quantitative measures and analytical tools are used to examine the requirements of the future system, the landscape of the resource options feasible across the planning horizon and the optimal strategy to procure resources based on PGE's understanding of the landscape. The key assumptions built into this analysis are the result of 12 months of iterative engagement with stakeholders through PGE's public Roundtable discussions.[79]

[79] https://portlandgeneral.com/about/who-we-are/resource-planning/resource-planning-engagement/resource-planning-meeting-materials

Figure 23 depicts a conceptual diagram of the 2026 CEP/IRP analytical process which is described below. At a high level, the process is to:

- Estimate system needs
- Evaluate resource options
- Develop a resource plan

Figure 23. CEP/IRP Analytical Process



An assessment of the current system is the first step in IRP analysis and results in four quantitative measures of system needs described in detail in Section 6.6.1: Energy Needs, Capacity Needs, Renewable Portfolio Standard Needs, and Flexibility Needs. Needs capture the gap between PGE's owned and contracted resources, and the forecasted growth of the system and policy obligations. Key inputs to the identification of system needs are load forecasts and existing resources. Load forecasts are discussed in detail in Chapter 6 and Appendix Section H.8. Existing and planned resources are described in Appendix F. Two (2) key measures of need are Energy Need and Capacity Need. Energy Need measures quantity of energy generation capability necessary to meet average load in each month - recognizing the diminishing role of thermal operations under policy constraints, and the second measures the quantity of generation capacity capability to meet load under extreme weather conditions and maintain system reliability. The modeling of emissions constraints resulting in Energy Needs are discussed in Chapter 6. Capacity Needs are estimated using loss of load probability modeling discussed in Appendix Section H.5 and detailed in Section 1.5 and Chapter 6.

To complement the assessment of system needs, the IRP evaluates various resource options. These resource options represent the Company's best understanding of generating technologies that could meet system needs between 2027 and 2046. Resource options, including their costs as estimated in the LUCAS model in Appendix Section H.3, energy values as estimated in Aurora outlined in 6.4, and capacity contributions as estimated in Sequoia are described in detail in 6.5. Energy values are derived through a production cost simulation described in Appendix Section

H.2.2, and effective load carrying capability (ELCC) is estimated through Appendix Section H.5. Additionally, some resource options are accessed by extra-regional transmission projects, which are described in Chapter 5.

After needs and cost/benefit streams of resource options are estimated, the IRP tests resources to assess their impact on needs through Portfolio Construction. Portfolio Construction compares the needs and resource options across the planning horizon and optimizes for the least-cost portfolio. For details on Portfolio Construction, see Appendix Section H.6 (ROSE-E) and Appendix Section H.7 (ARIA).

The process of estimating needs, quantifying the costs and benefits of resource options, and constructing least-cost portfolios is done under various futures and across many scenarios, described in Section 7.2. Futures capture uncertainty in key economic inputs such as load and energy prices in Section 6.6, while scenarios allow for the comparison of various fixed planning environments that attempt to quantify the effect of discrete policy or resource procurement pathways (described in Appendix I). The numerous resource buildouts produced through modeling futures and scenarios are scored as described in Chapter 7 to identify the least-cost and least-risk resource buildout.

The HB 2021 Preferred Portfolio is the least-cost, least-risk resource buildout that meets needs and policy requirements, including the emissions reductions targets outlined in HB 2021. Given the affordability and execution risks associated with this portfolio, PGE developed the Continued Progress Portfolio. The Continued Progress Portfolio reflects the work of the 2026 CEP/IRP to capture and quantify the uncertainties in the planning environment and identify the most affordable 20-year plan that meets system needs, including reliability and makes significant progress towards decarbonization requirements. PGE's 2026 CEP/IRP develops a Near-Term Action Plan as described in Chapter 2 that is informed by both the HB 2021 Preferred Portfolio and Continued Progress Portfolio. The Action Plan proposes the quantity of resource additions required in the coming two (2) to five (5) years to best prepare the company to meet energy needs affordably and achieve progress on emissions reduction requirements.

4.2 Modeling Overview

PGE uses a suite of analytical models for the 2026 CEP/IRP, as introduced in the section above. However, there are three (3) core modeling exercises in the 2026 CEP/IRP:

1. Production Cost Simulation
2. Resource Adequacy
3. Capacity Expansion

PGE uses Aurora for production cost simulation. The WECC wide model of generating resources simulates economic dispatch in the region, resulting in hourly prices and revenue estimates of

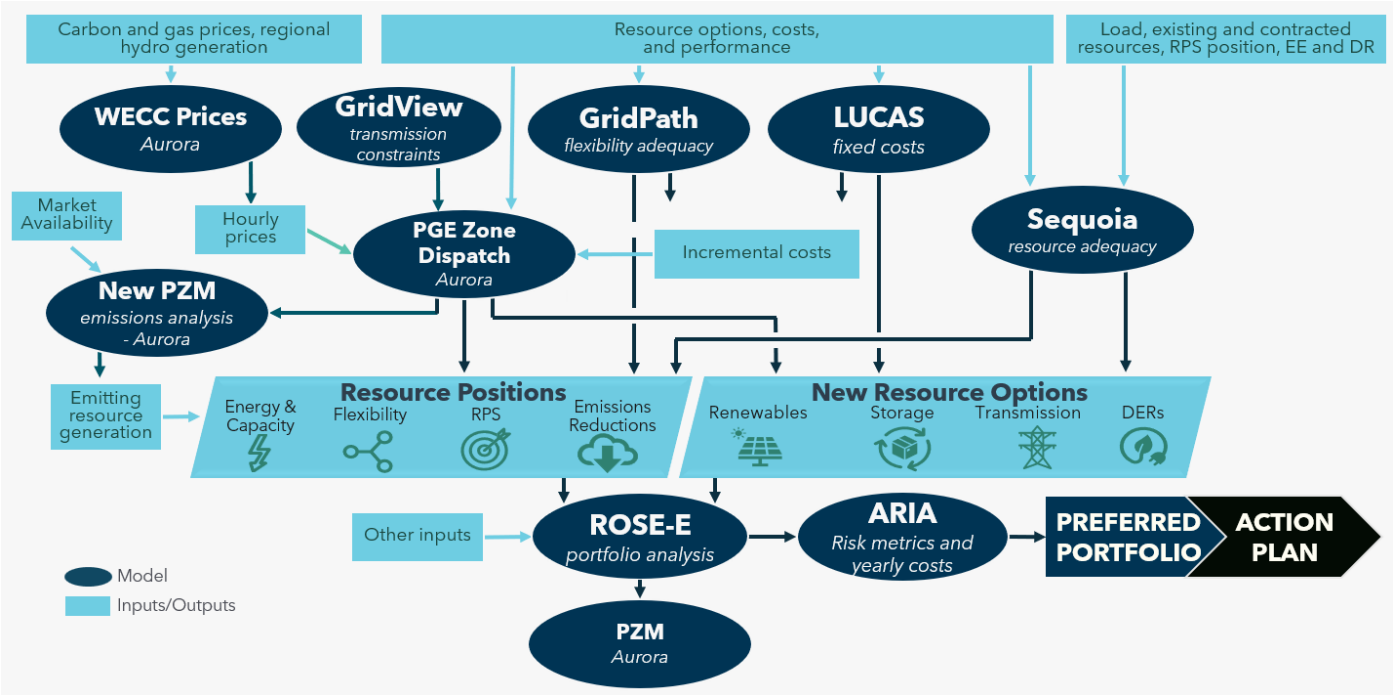
resource options. The objective of a production cost simulation is to minimize system costs with respect to median operating conditions. See Appendix Section H.2.2 for details.

Resource Adequacy assesses the reliability of PGE's system by modeling plausible load and resource combinations that stress the system's ability to serve load. PGE uses an hourly loss-of-load probability model, Sequoia, which has the objective of minimizing unserved energy and determines the amount of capacity needed to meet the industry standard 1-event-day in 10-years reliability metric. Sequoia is also used to evaluate capacity contributions of resource options. See Appendix Section H.5 for details.

Capacity expansion is conducted through PGE's ROSE-E model. This model identifies required resource additions in each year, meeting system needs and policy objectives while minimizing costs across the planning horizon. See Appendix Section H.6 for details.

Figure 24 displays the three (3) core modeling components discussed above and the host of other models which provide inputs or process outputs from Aurora, Sequoia, and ROSE-E. All models and their related assumptions, inputs, and outputs are detailed in Appendix H.

Figure 24. PGE's 2026 IRP Modeling Flow



4.3 Modeling Considerations

In the 2026 CEP/IRP, simplifying assumptions are used to represent complex market dynamics that will unfold in the coming years. PGE uses three (3) need futures, three (3) technology cost futures, and thirty-seven (37) price futures in the attempt to capture a range of unknown economic conditions across the 20-year planning horizon (See Section 6.6). Simulating resource buildouts

across these 333[80] futures is meant to provide a reasonable representation of uncertainty. Many uncertainties in technology location, transmission, generation, and costs are updated to provide a higher fidelity assessment of resource procurement decisions as PGE takes the Near-term Action Plan that results from the 2026 CEP/IRP and seeks competitive offers from the market.

[80] 3 Need Futures x 3 Technology Cost Futures x 37 Price Futures = 333 Futures

5 Transmission Requirements

This chapter describes the transmission environment facing PGE, the implications for future resource access and reliability, and the framework used to evaluate transmission solutions in the 2026 CEP/IRP. Additional details regarding PGE's transmission system, planning framework, and individual transmission alternatives are provided in Appendix J, Appendix K, Appendix Section K.2, and Appendix L.

Chapter Highlights

- Transmission availability is increasingly determining resource availability. Access to clean energy, firm capacity, and regional markets depends not only on the availability and economics of generation, but also on whether that generation can be reliably delivered to PGE customers.
- Existing regional transmission capacity is increasingly scarce. BPA and other regional transmission systems are highly subscribed, limiting opportunities for incremental firm service without upgrades or new infrastructure and increasing the strategic value of existing transmission rights.
- Changing regional power flows are creating new constraints. The emergence of the North of Pearl (NOPE) flowgate illustrates how changing generation, load growth, and regional market participation can create constraints that affect PGE's ability to reliably move power across the system.
- PGE is pursuing a portfolio of transmission solutions. PGE's strategy combines optimization of existing infrastructure and transmission rights, Grid Enhancing Technologies, targeted PGE system upgrades, acquisition of third-party transmission rights, and participation or investment in regional and interregional transmission projects.
- Long development timelines require earlier action and greater optionality. Major transmission projects require many years to develop, while transmission capacity and project participation opportunities may be limited. Preserving future options can therefore require development commitments well before the ultimate generation resource or customer need is fully known.
- Regional planning is increasingly important but does not replace the need for PGE action. Initiatives such as WestTEC can improve coordination and identify efficient regional solutions, while PGE must continue advancing transmission opportunities necessary to protect reliability, resource access, and customer value.

Transmission expansion is increasingly foundational to PGE's ability to reliably serve growing customer demand, maintain affordability, and achieve Oregon's clean energy objectives. As regional energy and capacity needs grow, the focus on availability of generation alone is no longer sufficient, resources must also be interconnected and deliverable to PGE's system when customers need them.

The Pacific Northwest is transitioning from a region that historically benefited from available transmission capacity to one in which access is increasingly constrained. Existing regional systems

are highly subscribed, power flows are changing as generation and load patterns evolve, and new transmission infrastructure can require a decade or more to plan, permit, and construct. These conditions increase the strategic value of existing transmission rights and make timely development of new transmission capability increasingly important.

Since the 2023 IRP Update, several developments have reinforced this shift, including the emergence of the North of Pearl (NOPE) flowgate as a significant constraint, increasing limitations on incremental service across BPA's transmission system, advancement of major regional and interregional transmission projects, and completion of the first WestTEC study. Together, these developments reinforce the need to more closely integrate transmission and resource planning.

PGE's transmission strategy therefore emphasizes both maximizing the infrastructure available today and preserving access to the infrastructure customers may need tomorrow. This includes optimizing existing transmission rights and facilities, deploying GETs, advancing targeted upgrades to PGE's system, securing additional transmission rights, and evaluating participation and investment in regional and interregional transmission projects. Given long development timelines, PGE must also preserve strategic options and advance projects before future resource needs are fully certain where waiting could result in higher costs, lost access, or increased reliability risk.

5.1 PGE Transmission Planning Background

PGE's transmission system serves a region representing approximately half of Oregon's population and roughly two-thirds of the state's commercial and industrial activity. While PGE owns and operates the transmission system and Balancing Authority Area (BAA) necessary to reliability serve its customers, its transmission footprint is relatively compact and highly interconnected with the broader Western transmission system.

PGE's service territory is concentrated primarily in Oregon's Willamette Valley. PGE owns and operates approximately 268 miles of 500 kV, 334 miles of 230 kV, and 559 miles of 115 kV lines, 454 circuit miles of 57 kV transmission lines, together with 176 substations and switching stations. PGE plans, operates, and expands this system to reliably serve retail customer load while also providing transmission service to eligible wholesale customers consistent with FERC requirements and PGE Transmission's Open Access Transmission Tariff (OATT).

Most PGE-owned transmission infrastructure is located within its retail service territory and is designed principally to move power across and into that footprint. PGE's system is significantly interconnected to BPA and PacifiCorp's transmission network. BPA's network in particular is relied upon to deliver generation resources to PGE's service territory. PGE also owns strategically important transmission assets outside its service area, including facilities in central and southern Oregon and Montana. These include PGE's ownership interest in the Colstrip Transmission System and one of the three 500 kV circuits comprising the Northwest AC Intertie (NWACI), which provides connectivity between the Pacific Northwest and California. These historical assets hold significant strategic importance for PGE's existing clean energy portfolio, offering foundational geographic access to diverse power systems facilitating market transactions and access of clean energy sources.

When evaluating transmission requirements, PGE must consider two (2) distinct transmission needs: local and regional transmission access. Local transmission planning identifies the reinforcements

necessary to safely and reliably move power across PGE's system and deliver it to customers. PGE seeks to maximize the capability of existing infrastructure before constructing new facilities, including through GETs, targeted upgrades, and other operational improvements. Planned local transmission investments are described in Appendix K, and PGE's GETs strategy is described in Appendix J.

Regional transmission access determines whether generation outside PGE's footprint can reach PGE's system. Delivering these resources requires sufficient transmission capability and, where applicable, rights across third-party systems. These rights are increasingly scarce as regional load grows, new generation seeks interconnection, and existing transmission systems become more highly subscribed.

Regional transmission access is critically important to integrated resource planning. Identifying a cost-effective generation resource does not provide customer value if the resource cannot be interconnected and reliably delivered to PGE's system. Additionally, securing regional transmission access can expand the universe of generation resources available to customers, improve geographic and resource diversity, and reduce exposure to regional short-term market disruptions.

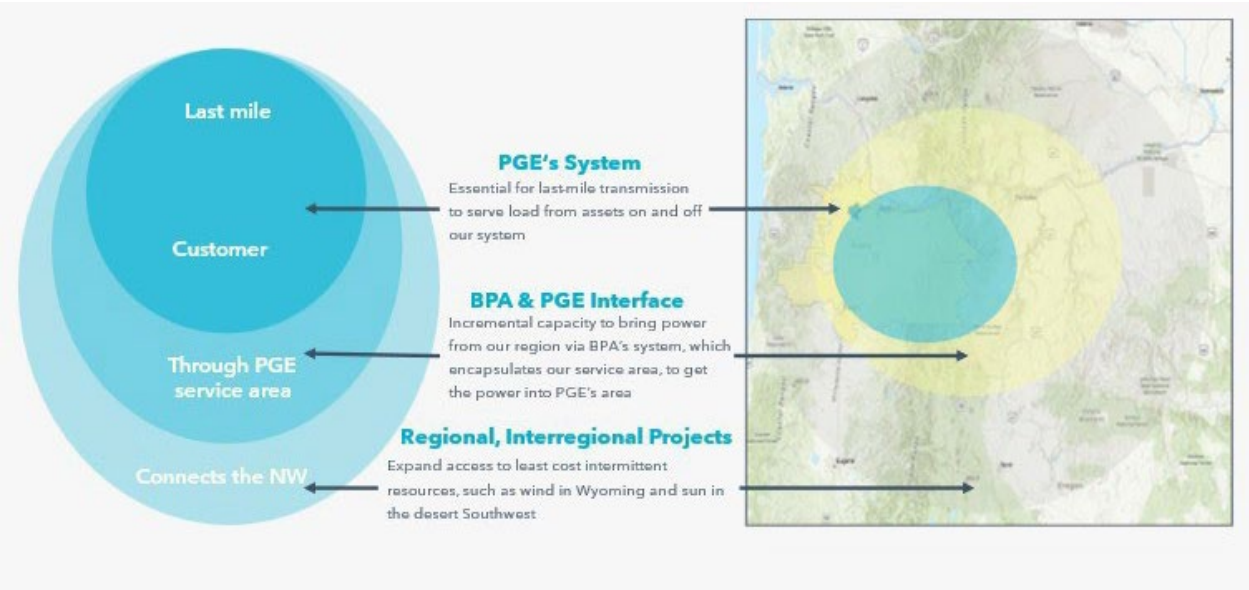
For these reasons, the 2026 CEP/IRP more fully integrates generation and transmission planning. PGE evaluates transmission not simply as infrastructure required after a generation resource is selected, but as a strategic resource that can enable future generation choices. This approach includes optimizing PGE's existing system, preserving and acquiring transmission rights, evaluating regional and interregional transmission investments, and advancing long-lead transmission opportunities where early action is necessary to preserve future resource access and customer value.

Additional detail regarding PGE's existing transmission system and local transmission planning is provided in Appendix K.

5.1.1 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 25.

Figure 25. PGE Transmission Concentric Circles



The innermost 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.

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.

Circle Three, the outermost 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.

5.2 Key Developments Since the 2023 IRP Update

PGE introduced combined generation and transmission planning in the 2023 CEP and IRP, recognizing that access to cost-effective generation increasingly depends on the availability of transmission to deliver those resources to customers. The OPUC subsequently directed PGE to further evaluate the transmission requirements associated with its resource strategy. PGE addressed Commission feedback in the 2023 CEP/IRP Update by significantly expanding the quantity of evaluated transmission options and introduced benefits related to diverse market access.

Since the development of the 2023 IRP Update, the regional transmission planning environment continues to change. Transmission constraints have intensified, major transmission projects have advanced, and regional planning efforts have provided greater visibility into the infrastructure that may be required over the coming decades. Collectively, these developments are incorporated into the 2026 CEP/IRP. PGE has strengthened resource planning by evaluating generation and transmission together. This integrated approach helps advance the discussions and decisions needed to ensure transmission infrastructure is built on time to support future generation resources.

5.2.1 Increasing Regional Transmission Constraints

Available transmission capability across the Pacific Northwest is becoming increasingly scarce as customer demand grows, new resources seek interconnection, and regional power flows change. This is particularly important for PGE because BPA's transmission network provides the primary pathway between PGE and many existing and prospective resources located outside PGE's service territory.

BPA's system is highly subscribed. As detailed in Appendix K, since 2023 PGE has faced numerous events in which BPA has suspended sales of short-term transmission products due to congestion specifically on the North of Pearl flowgate. Long-term transmission products are likewise unavailable and BPA's study processes to award new long term transmission plans of service have been suspended since 2023. Incremental firm transmission service increasingly depends on system reinforcements that require substantial investment and long development timelines.

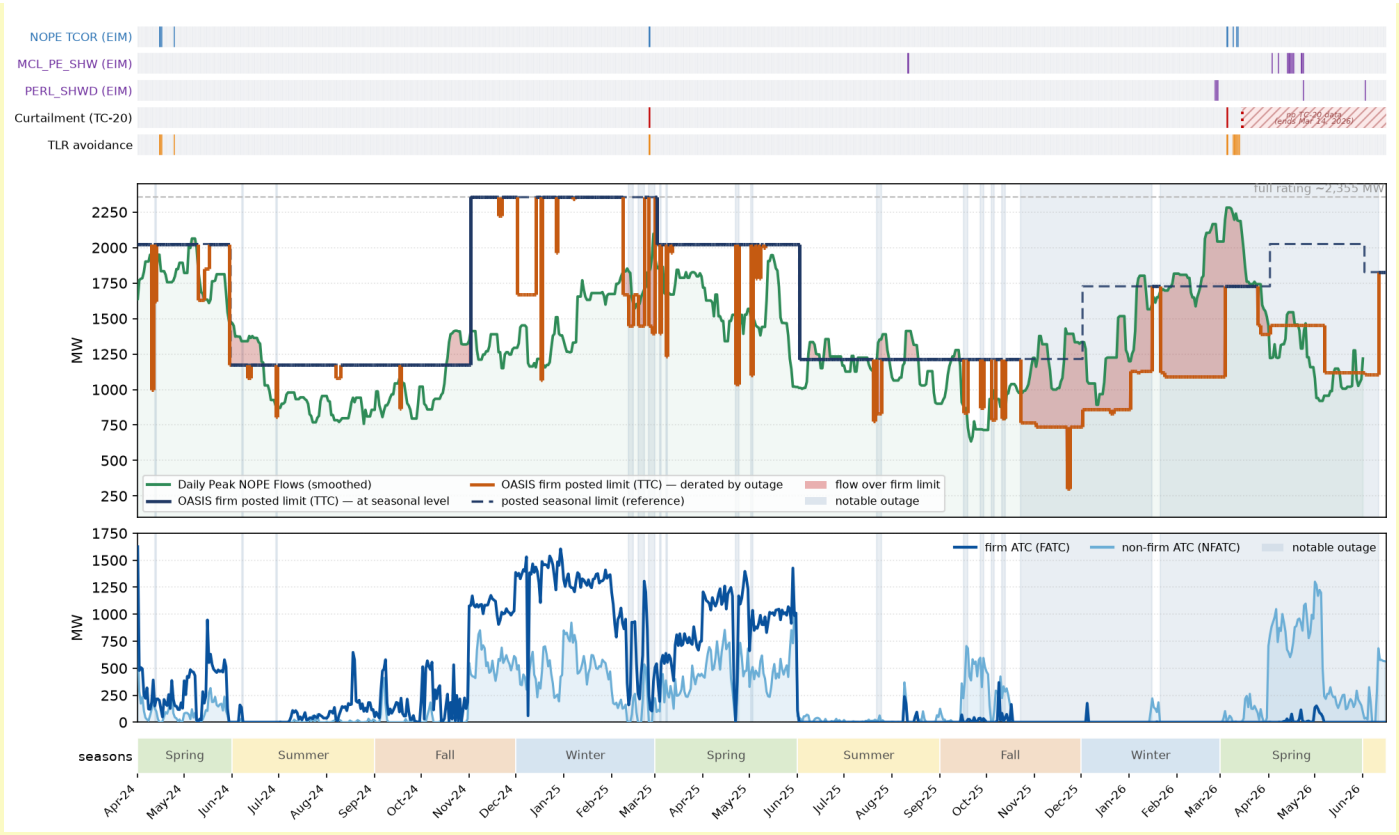
A BPA flowgate is a defined set of transmission facilities that operators monitor as a single constraint point because power flows across those facilities can collectively limit transfers between areas. Flowgates are relevant to resource planning because they indicate where transmission capacity may be insufficient to reliably or economically move energy from remote resources to load. Congestion on a flowgate is an essential lagging indicator of transmission unavailability: it shows that under actual system conditions, available transfer capability has already been consumed or reduced, increasing the risk that transmission service may be curtailed.

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 & #3

230kV lines, and the McLoughlin-Pearl BPA-Sherwood 230kV line. The flowgate was instituted on August 11, 2023, a few days before a heatwave that blanketed much of the Pacific Northwest.

Since its inception, the NOPE flowgate has experienced frequent congestion. Since the 2023 IRP Update, the frequency of that congestion has increased. Congestion has led BPA to take real-time mitigation actions that include sending congestion signals to the EIM marketplace that dispatched PGE Port Westward gas resources unexpectedly, halting short-term transmission sales, stopping all hourly redirects on BPA's system, and significantly curtailing transmission schedules across the region. Figure 26 below identifies the history of BPA congestion management actions (EIM redispatch, Transmission Curtailment, and Transmission Loading Relief), NOPE flows relative real time limits, and limited quantities of available short-term firm and non-firm transmission. This historical analysis shows that key parts of the existing transmission system are already operating at practical limits, underscoring the need for new infrastructure to maintain reliability and support additional generation deliveries to PGE.

Figure 26. Historical Congestion Management Actions, Flows, and Transmission Availability on the North of Pearl Flowgate



5.2.2 Key BPA Projects Affecting PGE

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 10, necessary for the safe and reliable operation of the region's transmissions system.

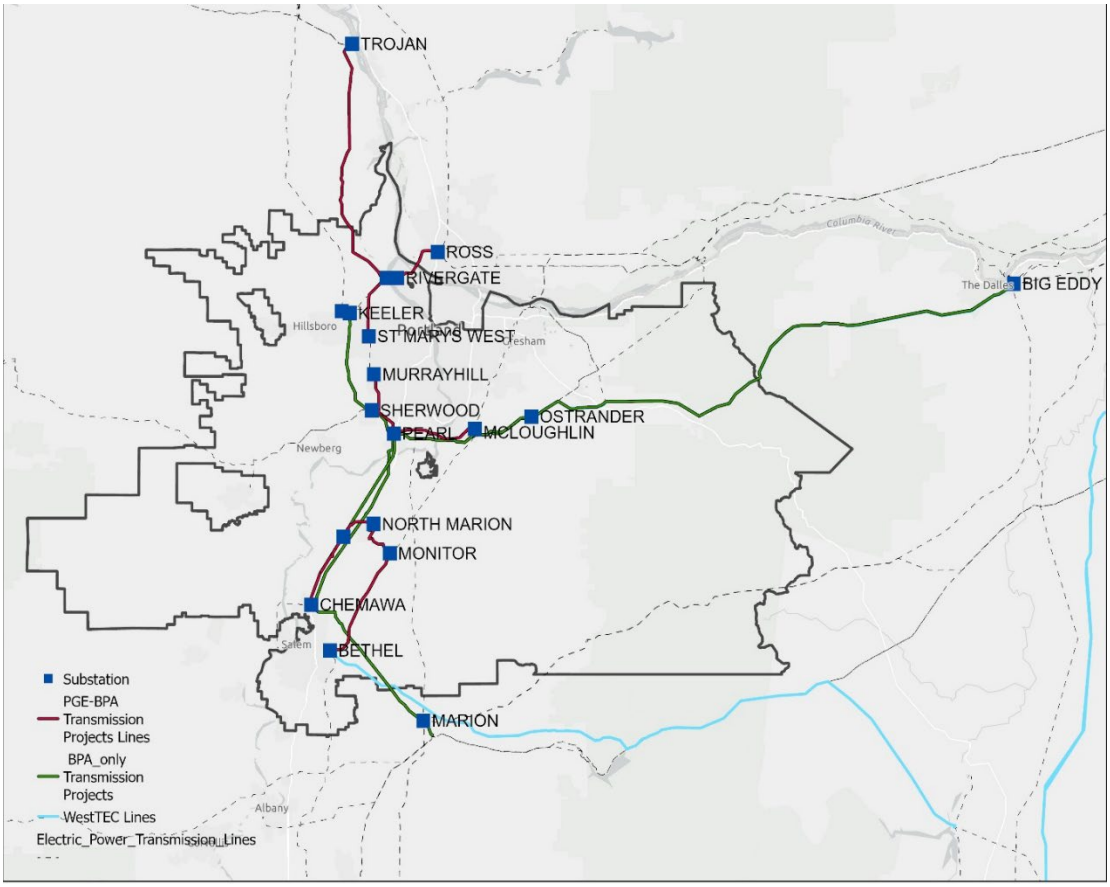
Several joint projects are inflight that will help address the NOPE flowgate constraint. In addition to joint projects, BPA has identified several projects that only involve work to their infrastructure that will have significant impact for PGE and its customers. The scoping and execution of these BPA projects has been accelerated and prioritized through BPA's dedicated Grid Expansion Reinforcement Portfolio (GERP) Program.[81]

Table 10. PGE-BPA and BPA-only Transmission Projects

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

[81] Grid Expansion and Reinforcement Portfolio - https://www.bpa.gov/energy-and-services/transmission/grid-expansion-and-reinforcement-portfolio

Figure 27. Important PGE- BPA and BPA-Only Transmission Projects



5.2.3 Advancement of Major Transmission Projects

While existing transmission capacity has become more constrained, several projects capable of expanding PGE's future transmission access have advanced. These developments create opportunities for PGE to strengthen reliability, access a broader and more diverse set of resources, and preserve flexibility as future customer and resource needs evolve.

Notable developments detailed in Appendix K:

- Commercial and transmission study advancement of the Warm Springs Power Pathway.
- Continued commercial, permitting, and procurement advancement of the North Plains Connector, including completion of the Final Environmental Impact Statement and initiation of EPC procurement.
- GRIP funding awards (Warm Springs Power Pathway and North Plains Connector) supporting transmission development.
- Progress on joint PGE-BPA transmission projects.
- Successful regional planning efforts supported by state policy.
- Further advancement and updates of BPA's GERP portfolio.

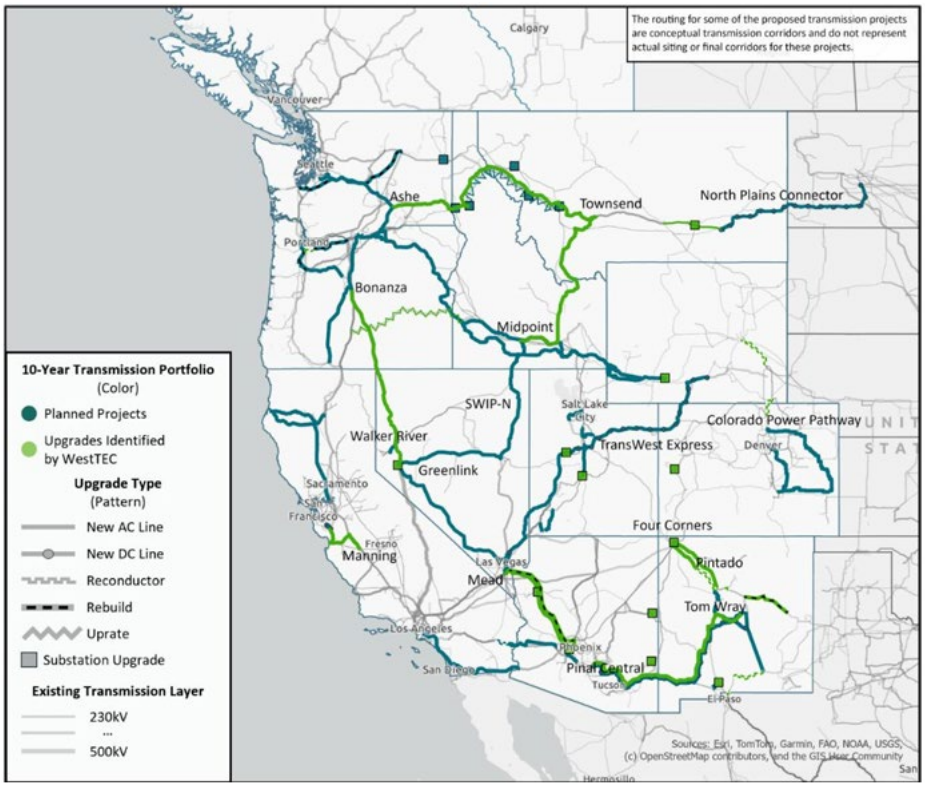
These projects are strategically important because major transmission infrastructure can require many years to plan, permit, finance, and construct. Participation decisions and development commitments may therefore be required well before the precise generation resource or customer need is known. PGE's transmission strategy increasingly considers the value of preserving these options alongside the cost of investment.

5.2.4 Western Transmission Expansion Coalition (WestTEC)[82]

Regional transmission planning has advanced considerably through the Western Transmission Expansion Coalition (WestTEC), a collaborative effort among utilities, transmission providers, states, and tribes to identify transmission needs and solutions across the Western Interconnection. WestTEC's 10- and 20-year studies are intended to provide a coordinated, West-wide foundation for transmission investment decisions that improve reliability, economic efficiency, and support state policy objectives.

The initial 10-year study, completed in February 2026, demonstrates the scale of regional transmission investment required. The study identified approximately 9,400 miles of major planned transmission projects representing approximately $47 billion of investment through 2035, as well as approximately 3,300 miles and $14 billion of additional upgrades needed to address regional reliability, deliverability, and economic constraints.

Figure 28. WestTEC 10-Year Horizon Transmission Portfolio



[82] https://www.westernpowerpool.org/about/programs/western-transmission-expansion-coalition

WestTEC provides an important regional perspective for PGE's transmission strategy. The 2026 CEP/IRP uses WestTEC findings to inform potential transmission expansion options, expected development timelines and costs, and regional and interregional pathways that could improve PGE's access to future resources. WestTEC's work also reinforces the importance of coordinated planning as regional load grows and existing transmission capability becomes increasingly constrained.

Western policymakers have similarly recognized the importance of moving from regional planning to execution. In June 2026, a group of Western Governors endorsed continued coordination around WestTEC-identified transmission needs and established the Transmission Permitting Alignment and Coordination Task Force (PACT). The multi-state task force supports the development of projects from the WestTEC study to ensure that the needs of the Western Interconnection in the 10-year horizon are met.

WestTEC is currently developing its 20-year study, expected in Q4 2026, which will expand upon the 10-year analysis through scenario-based planning and additional evaluation of regional benefits. PGE will continue to use these regional studies to inform, but not delay, actions necessary to preserve transmission access and advance projects that provide strategic value to customers.

5.3 Long-Term Transmission Options for Portfolio Analysis

PGE's 2026 IRP evaluates long-term off-system transmission options using assumptions found in the WestTEC 10-year study, wherever possible. The 2026 IRP continues to study the transmission expansion options included in the 2023 CEP/IRP Update which were recommended by a third-party consultant as requested by the Commission. The 2026 IRP also expands the set of modeled options to include additional WestTEC selected projects that are relevant for PGE's planning, including Garison-to-Ashe and Blueprint South. These options are used to test potential pathways for accessing BPA-area and interregional proxy resources, such as Gorge wind, Christmas Valley solar, North Dakota wind, and Nevada solar, while recognizing that many projects may require multiple transmission segments to reach PGE's system. Cost assumptions rely on WestTEC-published estimates where available and otherwise use public cost data, consistent with the chapter's broader framework for evaluating long-lead transmission opportunities that may preserve future resource access and customer value.

Figure 29 illustrates the transmission options studied in the 2026 IRP.

Figure 29. Overview of PGE Transmission Options

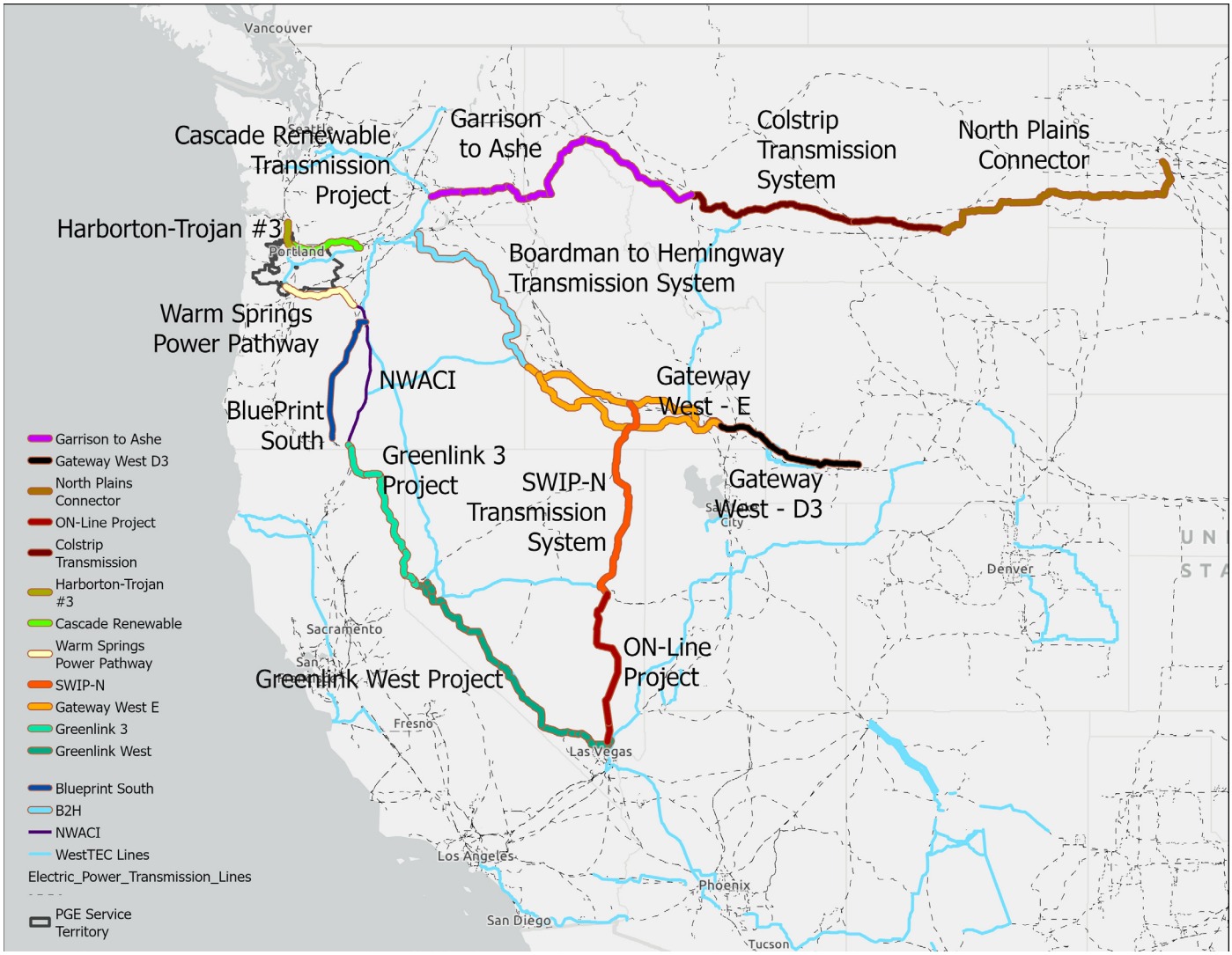


Table 11 provides a summary of the 11 transmission options discussed above and their assumptions used for portfolio analysis. PGE further describes each of these proposed transmission projects in Appendix K.

Table 11. Transmission Options

Project	Developer	Capacity (MW)	MW Available to PGE	COD	Extra-regional Market
Warm Springs Power Pathway Circuit 1	CTWS/PGE	1,000	1,000	2032	CAISO
Warm Springs Power Pathway Circuit 2 (Including BPA Upgrades)[83]	CTWS/PGE	2,000	2,000	2035	None
Cascade Renewable	CRT LLC[84]	1,100	1,100	2032	None
Harborton-Trojan #3	PGE	545	545	2035	None
Blueprint South	PacifiCorp	725	600	2035	CAISO
Gateway	PacifiCorp/IDP	5,000	400	2035	None
SWIPN	LS Power	4,073	400	2035	CAISO/DSW
Boardman to Hemmingway	IDP/PacifiCorp	1,000	400	N/A	None
Garrison to Ashe	BPA	1,500	330	2035	MISO/SPP
North Plains Connector	Grid United	3,000	270[85]	2032	MISO/SPP
Greenlink	NV Energy	800	490	2035	CAISO/DSW

[83] As further described in Appendix K Long Term Transmission Options, transmission planning results indicate that the capacity of WSPP Circuit One grows from approximately 1000 MW to 1800 MW following planned BPA upgrades in 2035. Circuit Two adds an additional 800 MW or more capacity contingent on planned BPA upgrades.
[84] Cascade Renewable Transmission, LLC includes three principal companies: PowerBridge, LLC, Sun2o Partners, LLC and NextEra Energy Transmission, LLC
[85] PGE's access to North Plains Connector (NPC) is 600 MW. The 2026 IRP models access 270 MW as early as 2032. An additional 330 MW of transmission capacity is made available following the selection of Garrison to Ashe no earlier than 2035.

5.3.1 Short-Term Transmission Options

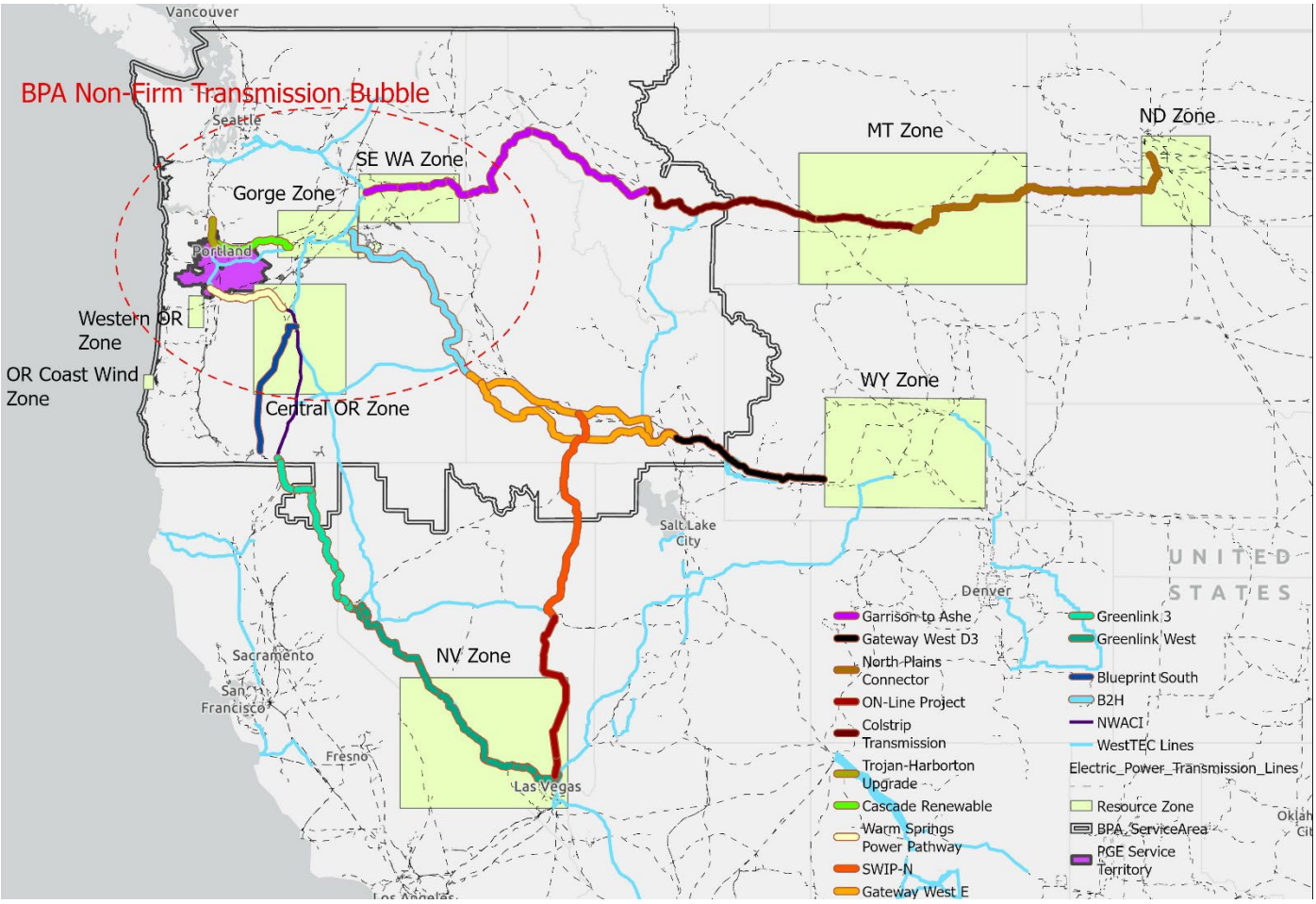
In addition to the transmission expansion options studied in the 2023 CEP/IRP Update, the 2026 IRP also forecasts the availability of short-term transmission service. When first introduced in PGE's 2025 RFP evaluation, PGE's assessment of short-term and non-firm transmission availability was based on historical congestion observations. Rather than relying solely on historical congestion observations, the 2026 IRP is using the GridView production cost modeling (PCM) tool given the 2035 WestTEC transmission case to forecast hourly utilization of key BPA paths and flowgates. For each hour of the modeled year, flows on twelve critical BPA interfaces and flowgates are compared against planned Total Transfer Capability (TTC) values. Hours in which flow reaches or exceeds 80% of TTC are treated as periods when congestion risk is elevated and non-firm transmission availability may be limited. These results are summarized using month-by-hour heatmaps and constraint frequency analyses, allowing the IRP to estimate how often non-firm transmission is likely to be available under future system conditions. This approach provides a forward-looking assessment of short-term transmission availability that is better aligned with expected changes in regional load growth, renewable generation development, transmission upgrades, and evolving west-wide dispatch patterns.

Non-firm transmission can play a role in expanding access to remote energy resources, but it is fundamentally different from long-term firm and conditional firm transmission products. BPA markets non-firm transmission only on a short-term basis, and it represents the lowest-priority transmission service available on the system. As a result, non-firm service is inherently interruptible and can be curtailed whenever capacity is needed to support higher-priority transmission rights. In addition, BPA may suspend the marketing of non-firm service entirely as a congestion management tool when certain flowgates become heavily loaded. Historical observations and PCM analysis both indicate that the North of Pearl (NOPE) flowgate presents the greatest risk to non-firm transmission availability. During periods of elevated south-to-north transfers, particularly those driven by high California solar production, strong Pacific Northwest wind output, and regional power transfers, BPA has historically restricted transmission activities and curtailed lower-priority transmission products to maintain system reliability. For this reason, the 2026 IRP explicitly models the risk that non-firm transmission may be unavailable during congested operating conditions rather than assuming constant availability throughout the year.

Because non-firm transmission is interruptible and cannot be relied upon during system stress events, resources that depend exclusively on non-firm transmission are not credited with capacity value in the 2026 IRP. Consistent with established resource adequacy principles, including the Western Resource Adequacy Program (WRAP), non-firm transmission is not an eligible transmission product for demonstrating resource adequacy. While resources utilizing non-firm transmission may contribute energy when transmission is available, their delivery cannot be guaranteed during the periods when capacity is most needed to maintain reliability. Accordingly, the IRP treats generation delivered over non-firm transmission as an energy-only resource. The energy contribution of these resources is discounted based on forecast transmission availability, while no resource adequacy or capacity accreditation is assigned. This treatment ensures that portfolio reliability assessments

remain consistent with regional resource adequacy frameworks and accurately reflect the operational risks associated with relying on interruptible transmission service.

Figure 30. 2026 CEP / IRP Transmission Options Including Generation Resource Option Zones



5.3.2 Transmission Requirements for New Generation Resources

PGE's IRP requires that planned generation resource additions be able to deliver to PGE's system. On-system resources including energy efficiency, VPP resources, and CBREs are recognized in PGE's planning as capable of serving PGE load without off-system transmission expansions. Off-system resources, are required to be paired with off-system transmission inventory. PGE's IRP assumes that new off-system generation resources will be delivered to PGE either on a combination of long-term and short-term transmission or short-term transmission exclusively. Off-system generation resources relying exclusively on short-term transmission avoid the incremental costs associated with new transmission but must be located in BPA's transmission footprint and rely on the limited inventory of forecasted non-firm transmission as forecasted in GridView. Short-term transmission resources are not credited with capacity value, and the forecasted delivered energy is partially derated consistent with GridView based forecasts of short-term transmission unavailability.

The quantity of off-system generation resources relying on long-term transmission is limited based upon available transmission inventory. All-long term transmission generation projects must be paired with transmission equal to 75% of the proxy resource's interconnect capacity. Consistent with the results of PGE's 2025 RFP, PGE assumes that existing BPA transmission service plans allow for 2453 MW of new generation resources located in the Gorge and Southeast Washington zones to be delivered on firm transmission rights following completion of select BPA GERP projects. Additional new generation resources relying on long-term transmission can be selected within the 2026 CEP/IRP following model selection of a requisite transmission expansion project including the transmission project's incremental costs.

6 Generation Requirements

This chapter describes the development of PGE's forecast generation needs, with details of PGE's load and DER forecasting processes and the impacts of recent procurement actions on PGE's resource portfolio. Additionally, descriptions of input assumptions and analysis methods provide context on the forecast capabilities of new generation resource options and the process used to model the impacts of uncertainty on needs.

Chapter Highlights

- PGE forecasts continuing load growth. The updated load forecast utilized for this CEP/IRP is characterized by increased industrial growth estimates.
- PGE has committed to additions of 1,015 MW of clean energy resources. These solar and battery storage resources, achieved through recent procurement actions, are expected to come online in the next two (2) years.
- Forecasted energy needs grow through the planning horizon. Without new resources, PGE's open energy position grows due to existing contracts and facilities exiting PGE's portfolio as customer load continues to grow.
- Forecasted capacity needs grow after 2028. PGE's summer capacity need is forecasted to reach 1197 MW and winter need forecasted to reach 960 MW in 2032, in the reference case.
- Planning analysis uses a diverse set of futures to assess cost and risk. PGE performs analysis under a broad range of future conditions, rather than relying on a single forecast. The 2026 IRP models portfolios across 333 futures, reflecting variations in system needs, market prices, and technology costs.

PGE's generation needs assessment establishes the core inputs in modeling future portfolios that include sufficient resources required to maintain system reliability and replace thermal generation to meet Oregon's HB 2021 decarbonization objectives. The models and methods used to estimate capacity and energy needs are primarily the same as those used for PGE's 2023 CEP/IRP[86] and 2023 CEP/IRP Update.[87] However, key input assumptions in PGE's load forecast and future base resource portfolio are updated to represent the most current understanding of anticipated demand and supply.

6.1 Load Forecast

- PGE's estimate of demand for electricity is called its load forecast. The load forecast has been influenced by rapidly evolving trends (such as customer usage patterns emerging from COVID-19, extreme temperatures and rapid large load growth) and the slower-moving, longer-term trends associated with the macroeconomic of PGE's service area. Section 6.1.1,

[86] See 2023 CEP/IRP, Chapter 6 and 2023 CEP/IRP Addendum, Chapter 2 – Need changes.
[87] See 2023 CEP/IRP Update, Chapter 3 – System Needs

describes current load trends. These trends are accounted for in different ways in PGE's load forecasting model. The primary components of PGE's load forecast are:

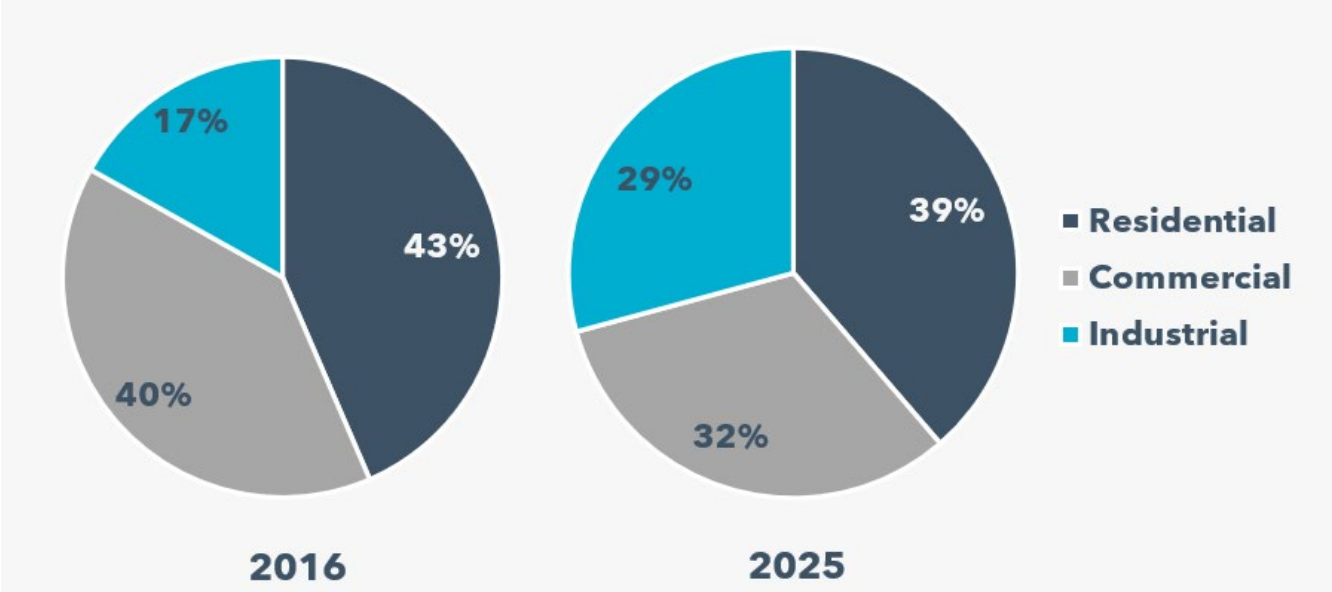
- Load forecast model: This model comprises two (2) segments that capture business cycle impacts, long-term trends, and key model inputs. Section 6.1.2 describes the top-down econometric forecast and how key inputs are considered. The analysis performed in the 2026 CEP/IRP utilized the May 2026 Corporate Load Forecast vintage, which was the most recently available vintage at the time analysis inputs were finalized.
- Incremental impacts associated with Load-Modifying DER input: The impact of nascent and rapidly evolving end uses, including transportation electrification, rooftop solar and building electrification, is forecasted in PGE's Distribution System Planning process. The load impacts of DERs are described in Section 6.2.1.

6.1.1 Load Trends

6.1.1.1 Industrial Growth

Energy deliveries to PGE's industrial segment have continued to increase, growing on average 10% per year from 2020-2025 driven by growth in the semiconductor manufacturing and datacenter segments. While the customer contracting enabled by recent rulemakings helps to provide additional confidence around large customer growth, the realization and timing of large projects create heightened uncertainty around PGE's load forecast.

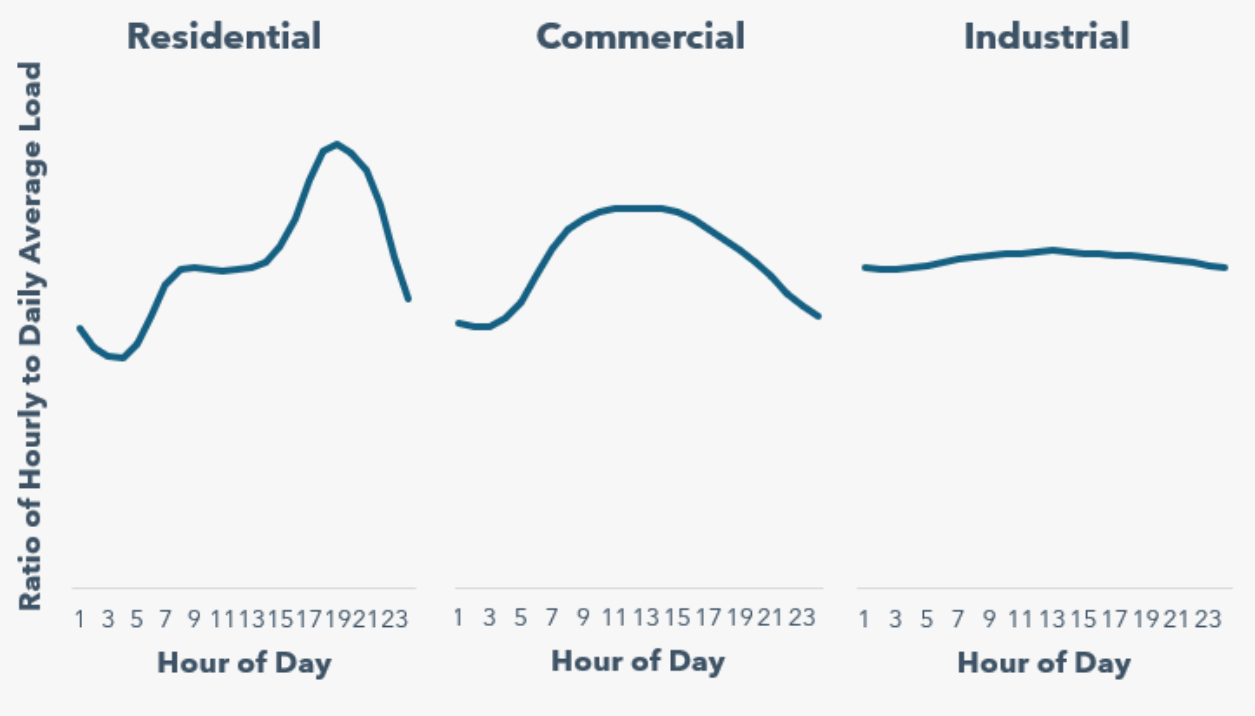
Figure 31. Annual Share of Energy Deliveries by Class (Excluding Loads Served by ESS)



This growth is significant to the regional planning environment, as a driver of total growth, but also to the shape of that load and the load forecast methodology itself. The share of load from the industrial customer class, which has a very different load shape than residential and commercial customers, has increased. PGE discussed evolution of its hourly shaping model, which has been

updated to reflect load at the customer class level in Roundtable 25-7.[88] Differences in load shape can inform resource needs; including energy, or capacity to serve summer or winter peak demand.

Figure 32. Diurnal Load Shape by Customer Class, 2025 Average



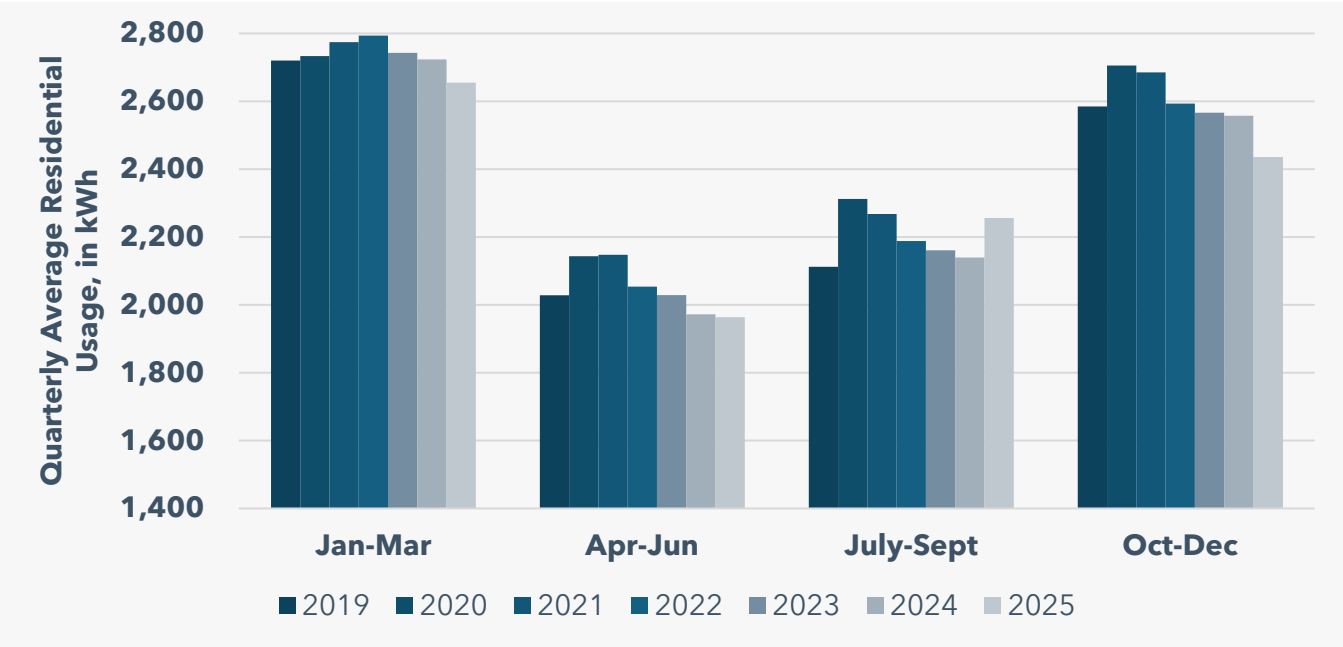
6.1.1.2 Residential Use

At the time of PGE's last 2023 CEP/IRP, the impact of COVID-19 on energy deliveries remained uncertain. While the most significant usage disruptions related to COVID-19 have been resolved, some longstanding trends have remained. The shift toward remote work, along with recurring wildfire smoke and extreme temperature events, including the 2020 Labor Day fires and the 2021 heat dome, appears to have accelerated customer adoption of technologies that improve home comfort and climate control.

Residential customer usage has increased during the summer cooling season reflecting increased air conditioning penetration and utilization. At the same time, electricity usage to support winter heating has decreased, as seen in Figure 33. The residential winter usage reductions are driven by decreased overall utilization, more efficient appliances, and warmer seasonal temperatures in recent years. These impacts are considered in the residential forecast model, which has been updated to reflect a shortened estimation period, structural break capturing reduced heating demand and include a trend associated with increased cooling usage to capture these impacts.

[88] https://portlandgeneral.com/about/who-we-are/resource-planning/combined-cep-and-irp/combined-cep-irp-public-meetings

Figure 33. Quarterly Weather Adjusted Average Residential Usage Per Customer



6.1.2 Load Forecast Model

PGE's load forecasting models take an econometric approach by estimating the relationships between PGE service area historical load and exogenous drivers. These exogenous drivers include seasonal and weather variables, macroeconomic indicators (building permits and employment) used to describe regional economic trends, and data reflecting estimated impact of load modifiers, including energy efficiency and rooftop solar generation.

Outside of the econometric regression, PGE's model includes an individual customer forecast for approximately 30 of its largest energy users. This forecast is informed by ongoing customer engagement and considers expected future operating patterns, historical load data, and executed customer contracts.

The impacts of building and transportation electrification are estimated outside of the econometric model by PGE's AdopDER model. The incremental impact to PGE's load is included as modifiers to the econometric forecast. The electrification forecasts are described in Section 6.2.

Appendix Section H.8 provides additional detail on the models that constitute the IRP load forecast. This includes how models were tested and selected, vintages of input drivers used for the IRP load forecast and integration of the AdopDER load data, the hourly simulation methodology and how the seasonal peak demand is estimated. This section also describes how rooftop solar has been

integrated into the econometric load forecast. PGEs load forecast method and results were presented to stakeholders in Roundtables 25-7[89] and 26-5.[90]

In addition, PGE's Reference Case load forecast incorporates several key model assumptions:

- Weather: PGE's load forecasts reflect normal or expected weather conditions throughout each year. For this IRP, the expected weather conditions are represented by a trended model for heating and cooling degree days to reflect the gradually warming regional climate. The forecasts do not attempt to predict, for example, an El Niño winter, a particularly hot summer or any weather event in any given year.
- Direct access: Customers with approximately 290-megawatt average[91] (MWa) of combined commercial and industrial load in PGE's service area have opted out of PGE's cost-of-service (COS) supply rates and receive energy from electricity service suppliers (ESS). This IRP portfolio analysis excludes these customer loads. Consistent with prior IRPs, PGE includes one-year direct access customers in its IRP planning because they may return to PGE's COS rates with little notice.

6.1.3 Uncertainty and Load Scenarios in IRP

All forecasts have inherent uncertainty. For example, uncertainty is associated with the model input data, the selection of the model itself and the relationships established within it, and factors external to the model. To reflect uncertainty in the model input data and the relationships estimated in the load forecast, PGE empirically develops high- and low-load growth scenarios. These scenarios focus on alternate futures for macroeconomic drivers combined with scenarios for key model inputs: rooftop solar, electrification, and large customer growth. Table 12 shows the inputs used to create the low, reference, and high load forecasts. Inputs taken from the AdopDER model are described in Appendix Section H.1.

Table 12. Inputs to Load Forecast Scenarios, Case and 20 Year Average Growth Rates (2026-2045)

Input	Low	Reference	High
Customer Growth	0.3%	1.0%	1.7%
Employment Growth	0.4%	0.6%	0.9%
Large Customer	2.5%	6.6%	8.1%
Rooftop Solar	8.8%	7.4%	5.3%
Electrification[92]	15.9%	16.3%	17.2%

[89] https://assets.ctfassets.net/416ywc1laqmd/5htkxP4gUoP87kOxDAGk8k/8dee7d830b3d4cf665bcaa081fda4d8d/CEP_IRP_Roundtable_Oct_25-7.pdf

[90] https://assets.ctfassets.net/416ywc1laqmd/4JHmwOPlcaks2vCQsQfRDL/38d092dd2dd743256c389f7f892f5b36/CEP_IRP_Roundtable_Jun_10__2026_-_5.pdf#page=1

[91] Reflecting loads serviced under both the Long Term and New Load Direct Access programs.

[92] Electrification line includes both Transportation and Building electrification forecasts from the AdopDER model.

The individual customer forecasts developed to create the Large Customer forecast input focus on slowed growth in the Datacenter segment for the Low Case and a resurgence of semiconductor customer growth in for the High Case.

The resulting load scenarios are summarized in Table 13.

Table 13. Load Forecast Scenarios, 20 Year Average Growth Rates (2026-2045)

	Low	Reference	High
Summer Peak	0.9%	2.8%	4.0%
Winter Peak	1.2%	3.1%	4.3%
Total Average Energy	1.2%	3.7%	5.0%
Residential Energy	0.9%	1.7%	2.8%
Commercial Energy	-0.1%	0.3%	0.9%
Industrial Energy	3.2%	7.5%	9.0%

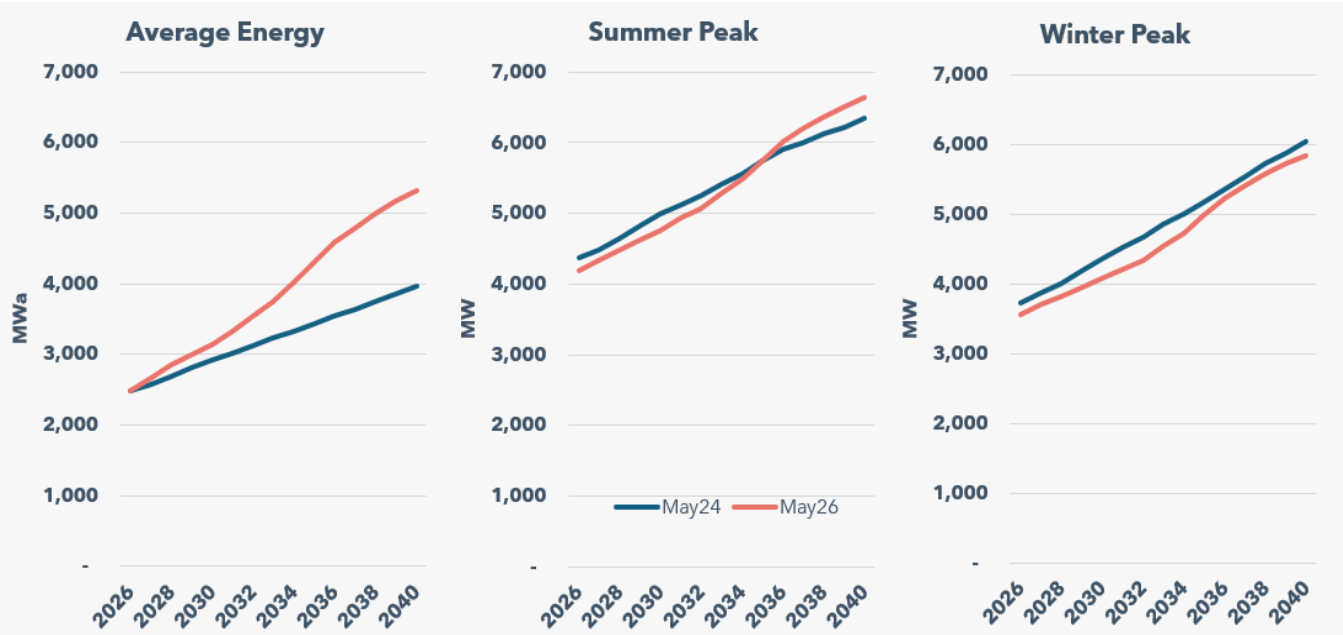
In addition to the Low, Reference and High scenarios, a scenario which truncates all growth associated with Large Loads was developed for comparative analyses. Refer to Section 7.4.2 Core Growth Only Scenarios for further details.

6.1.4 Comparison of 2026 IRP to 2023 IRP Update

Rapid industrial growth has created a dynamic and continually evolving load forecasting landscape. The analysis presented in the 2026 IRP is based on a load forecast model run completed in May of 2026. Figure 34 below compares three (3) major outputs of the forecast: Energy (in MWa), Summer Peak Demand (in MW) and Winter Peak Demand (in MW) as compared to the May 2024 forecast which was used to inform the 2023 IRP Update.[93]

[93] The methodological changes with respect to how Distributed Energy Resources are integrated into the load forecast change the presentation of load forecast data. The May 2024 values have been reconstituted to show the forecast net of DER's for a like comparison to the May 2026 load forecast. This presentation of the load values varies from that shown in prior IRP materials.

Figure 34. Comparison of 2026 IRP Load Forecast Versus 2023 IRP Update



6.2 Key Load Inputs

6.2.1 Distributed Energy Resources (DERs) Impact on Load

PGE develops a forecast of distributed energy resource (DER) adoption and associated hourly load impacts on a regular basis. This forecast provides insight into how market-driven DER adoption affects both PGE's bulk power system and distribution system. It also informs the amount of demand response available to shape and shift load on the bulk system. As such, the DER forecast is an input to multiple planning processes, including the Distribution System Plan (DSP) and the Integrated Resource Plan (IRP). This section provides a description of the methodology and results from the DER forecast.

The DER forecast is developed using PGE's AdopDER model, which simulates the adoption of more than 60 DER technologies and technology combinations. The model uses a point-in-time dataset derived from PGE systems that characterizes each service point, including building type and vintage, heating and cooling systems, vehicle weight classes and fuel types, and existing interconnected solar PV and storage. AdopDER also incorporates projected customer growth across PGE's service territory to estimate DER eligibility, adoption, and load impacts over a 20-year forecast horizon from 2027 through 2046. Its outputs are sensitive to the different underlying assumptions, including policy, economic conditions, and regional adoption trends.

Building on this foundation, AdopDER simulates the market adoption and impacts of building electrification, transportation electrification, and solar PV adoption, while also simulating adoption and expected customer participation in current and future demand response programs. These inputs are continuously refined as new data becomes available. For this 2026 IRP/CEP, three (3) adoption scenarios, reference, high, and low, were developed using varying assumptions related to

costs, adoption trends, and policy signals. These scenarios reflect how DER deployment may evolve under different market, regulatory, and customer conditions.

Resources in this section are classified based on how they are represented in the IRP modeling framework. Classification does not limit the resource's potential role in VPP portfolio. Resources are reflected in IRP analysis in one of two (2) ways:

- Load-modifying resources, such as building and transportation electrification, distributed solar, and cost-effective energy efficiency, are incorporated as adjustments to the load forecast.
- Selectable resources, such as demand response (also commonly referred to as flexible load), non-cost-effective energy efficiency, and dispatchable standby generation, are represented as candidate resource options that the ROSE-E model can select in portfolio analysis (Section 7.10).

PGE orchestrates all DER configurations through the VPP, accounting for the availability, capacity, and reliability of each resource at its current capability stage. As capabilities mature, the planning representation of a resource can change. For example, in this IRP, modeling of demand response resources has transitioned from an exogenous load modifier to a selectable resource evaluated alongside supply-side options. Distributed solar is expected to follow a similar trajectory, where it is visible and forecastable today (capability stage 1), with dispatchable value emerging through storage pairing (capability stage 2) in the future iterations of planning. VPP resource capability stages are discussed in detail in the 2024 DSP (Chapter 5, Section 5.1.3.2).[94]

6.2.2 Load-Modifying DERs

6.2.2.1 Building Electrification

Building electrification is represented as an incremental load addition to the corporate load forecast, reflecting the transition of end uses such as space heating, water heating, and cooking from fossil fuels to electricity. Within AdopDER, these impacts are developed through customer-level stock turnover and technology adoption modeling, which estimate both the magnitude and timing of new electric load. These impacts are then aggregated to the system level and applied to the baseline econometric forecast, increasing overall energy consumption and contributing to winter peak demand due to the temperature sensitivity of heating loads. The resulting effect is a structural upward shift in both annual energy and seasonal peak requirements, which directly increases the system's capacity need in the IRP framework. Figure 35 shows the megawatt-average (aMW) impacts forecasted due to building electrification for reference, low and high adoption scenarios.

6.2.2.2 Transportation Electrification

Transportation electrification is similarly modeled as a load addition, but with distinct temporal characteristics that influence system peaks differently than building electrification. AdopDER

[94] https://edocs.puc.state.or.us/efdocs/HAA/haa333816025.pdf#page=72

simulates the adoption of electric vehicles and charging infrastructure using both macro-level adoption trends and bottom-up customer data, producing hourly charging load profiles that reflect expected customer charging behavior. These impacts are incorporated into the load forecast as incremental energy and peak demand, with a tendency to increase evening and overnight loads depending on charging patterns. At the system level, transportation electrification contributes to both energy growth and emerging peak conditions, particularly in the summer, and is treated as a fundamental driver of load growth. Figure 36 shows the aMW impacts forecasted due to transportation electrification for the three (3) considered scenarios of different levels of adoption.

6.2.2.3 Distributed Solar Photovoltaic Adoption

Distributed solar photovoltaic (PV) is one of the key VPP resources. It's adoption is incorporated in the IRP as a reduction to net load in the corporate load forecast, offsetting underlying gross consumption. IRP modeling reflects how solar is currently reflected in the load forecast, not its potential role in VPP portfolio. Distributed solar is part of PGE's VPP today at capability stage 1. Its location and expected production are visible and forecastable, and PGE uses that information in VPP portfolio dispatch planning today.

In the modeling framework, gross load is first established by combining the corporate load forecast with electrification-driven load additions, after which solar generation profiles are applied to reduce load on an hourly basis. These impacts are derived from AdopDER's simulation of customer adoption and system performance, producing time-specific reductions that are most pronounced during daylight hours. While solar PV reduces total energy requirements and can lower peak demand under certain conditions, its contribution is highly dependent on alignment with system peak timing. As a result, solar primarily reduces midday load and overall energy need, while providing more limited capacity value during peak periods, and is therefore reflected as a net load adjustment rather than a dispatchable resource. Figure 37 shows the aMW impacts of distributed solar adoption for the three (3) scenarios.

Figure 35. aMW Impact of Building Electrification (BE) for Different Scenarios[95]

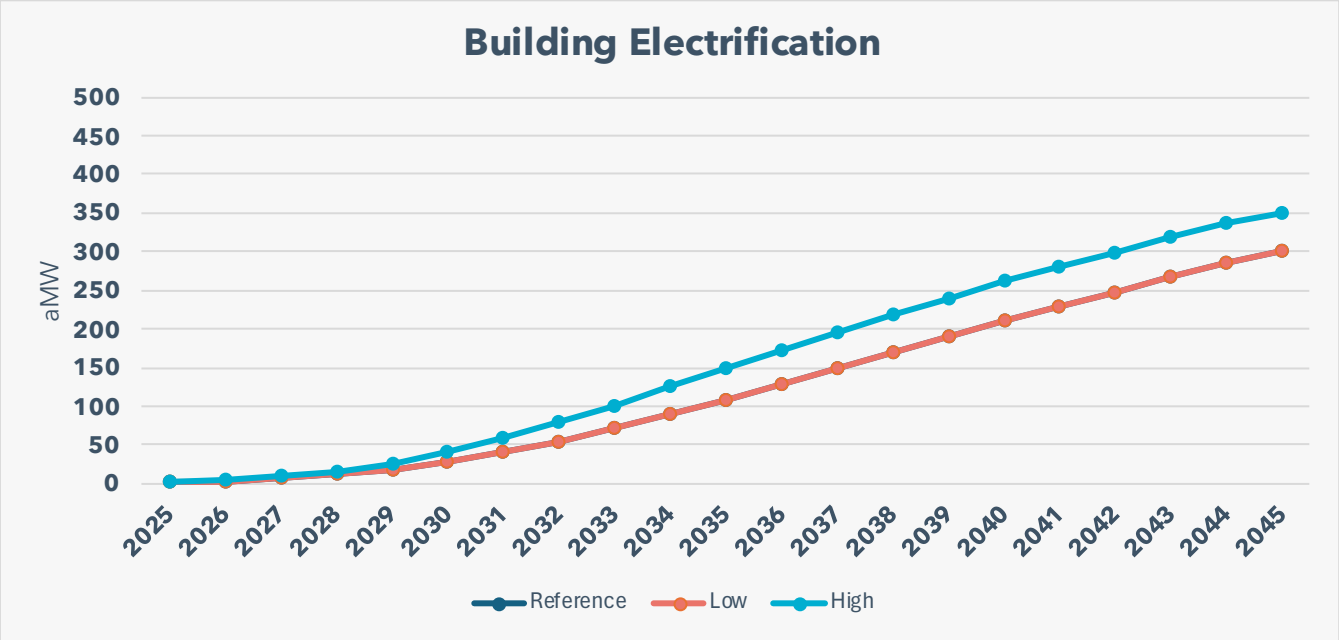
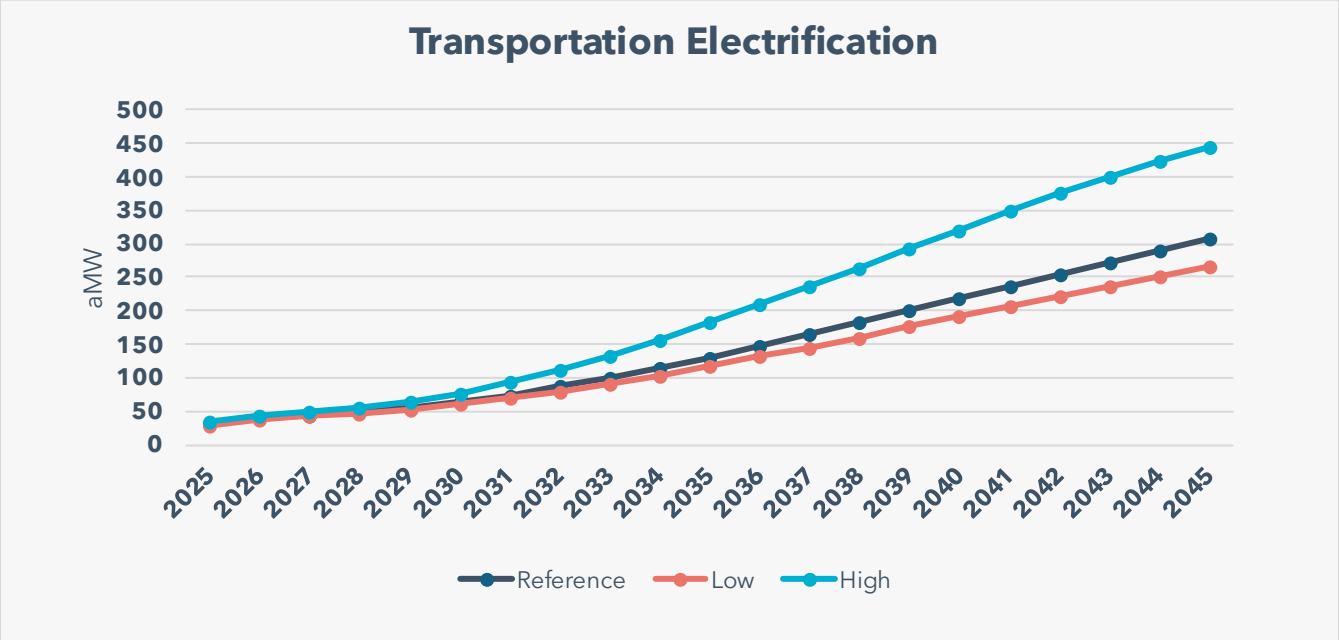
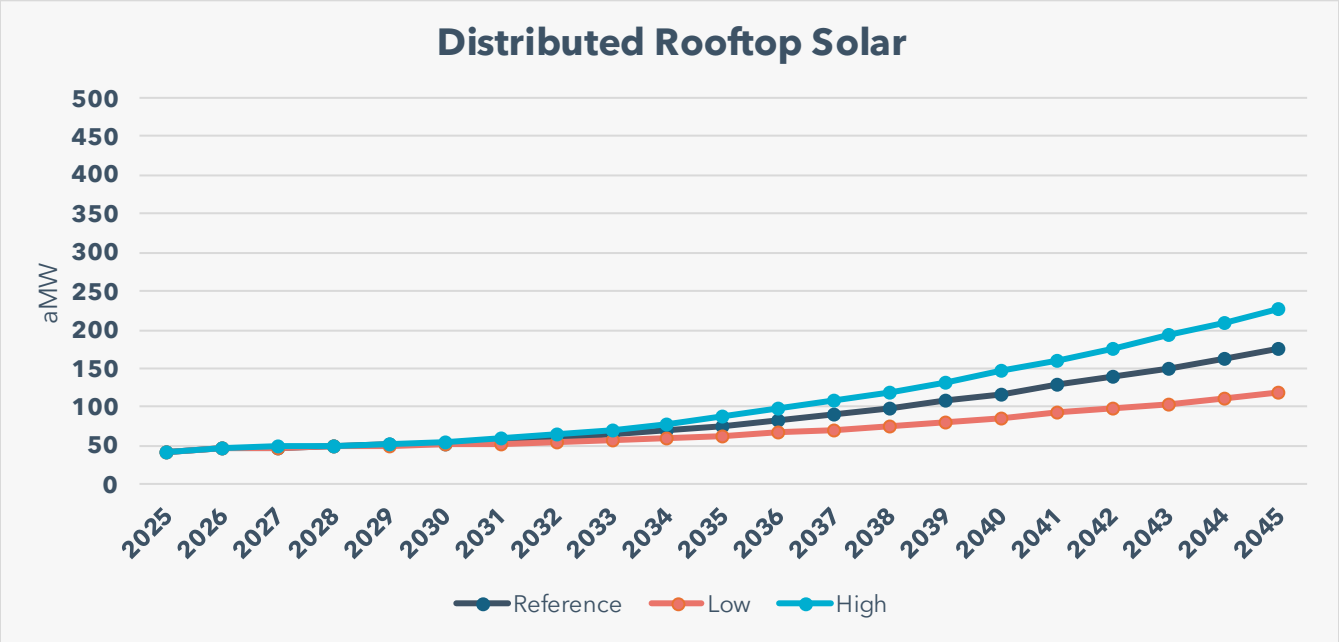


Figure 36. aMW Impact of Transportation Electrification (TE) for Different Scenarios



[95] The reference scenario plot is overlapped with the low scenario plot in the case of Building Electrification.

Figure 37. aMW Impact of Distributed Rooftop Solar for Different Scenarios



6.2.3 Demand Response Impacts

AdopDER calculates cost-effectiveness metrics for each demand response resource; however, for the 2026 IRP/CEP, these resources are no longer implemented as exogenous load modifiers based on cost-effectiveness classification. Instead, AdopDER outputs are translated into IRP inputs that inform both net load impacts and resource options within portfolio analysis. Specifically, demand response programs are represented in ROSE-E as selectable resources within a binned framework as described in Appendix Section G.2, where their costs, load shapes, and availability are used to determine economically optimal deployment levels. The incremental capacity growth of demand response resources for summer and winter seasons over the planning horizon are presented in Appendix Section G.2.4.1. This approach allows demand response to compete directly with supply-side resources for selection, with MW quantities determined endogenously as part of a broader virtual power plant (VPP) resource portfolio. This transition illustrates how a resource's planning representation evolves with its capability stage: as demand response matured in dispatchability, measurement, and forecast confidence, its treatment moved from a load-forecast adjustment to a resource evaluated alongside supply-side options.

This 2026 IRP/CEP reflects the most up-to-date DER forecast available at the time of analysis, including results from the October 2025 AdopDER run, which incorporates updated federal and state policy assumptions related to solar PV and electric vehicle adoption.

6.2.4 Energy Efficiency Impact on Load

PGE relies on the Energy Trust of Oregon (ETO) to identify energy efficiency (EE) measures available in the IRP using its resource assessment modeling tool. This modeling tool uses a cost-effectiveness screen on EE potential to forecast two (2) metrics: (1) Cost-Effective (CE) energy efficiency measures

and (2) Non-Cost-Effective (NCE) energy efficiency measures. EE potential for IRP analysis is described below with additional details on ETO's EE forecast methodology provided in Appendix Section G.1 (NCE EE) and Appendix Section H.8.3.2 (CE EE). This IRP incorporates the ETO's most recent long-term EE savings forecast from Fall 2025.

The CE EE measures are incorporated directly into PGE's IRP load forecast as an explanatory variable and assumed to be part of the base portfolio in IRP analysis. The NCE EE measures are aggregated for incorporation into IRP's portfolio analysis so they can be selectable by the ROSE-E model as incremental resource additions, informed by costs.

6.2.4.1 Cost-Effective EE

PGE incorporates the ETO's cost-effective EE savings forecast as incremental reductions to the load forecast used for IRP analysis. The cost-effectiveness screening involves 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 EE measure being evaluated. The screening relies on some cost assumptions approved through OPUC Docket No. UM 1893, which has broadly resulted in increasing avoided cost assumptions resulting in increasing amounts of EE measures to be deemed cost-effective, and therefore results in increasing incremental reductions to the load forecast in each IRP. This can be seen in Figure 38, which shows the cumulative (from 2027) cost-effective EE assumed in this IRP compared to the 2023 IRP. From 2027 through 2031 (Action Plan window), ETO projects that cost-effective EE will provide roughly 182 MWa of energy savings, averaging roughly 36 MWa of load reduction each year in this IRP. For comparison to actual implementation, roughly 32 MWa were saved from PGE's energy efficiency measures in 2025.[96] To align with forecasted EE savings assumed as cost-effective reductions to load, actual EE implementation would have to outpace recent installations and sustain at this higher level into the future.

[96] Preliminary 2025 metrics provided by the ETO, included in PGE 2025 Purpose and Progress Report, https://downloads.ctfassets.net/416ywc1laqmd/v4ZsP7g6rt5Y8guOQVR4m/5435351a61703614b00c3c4048b4bc7d/412651-2025-ESG-Report-Print_FNL-03.12.26.pdf.

Figure 38. Cost-Effective Energy Efficiency in IRP

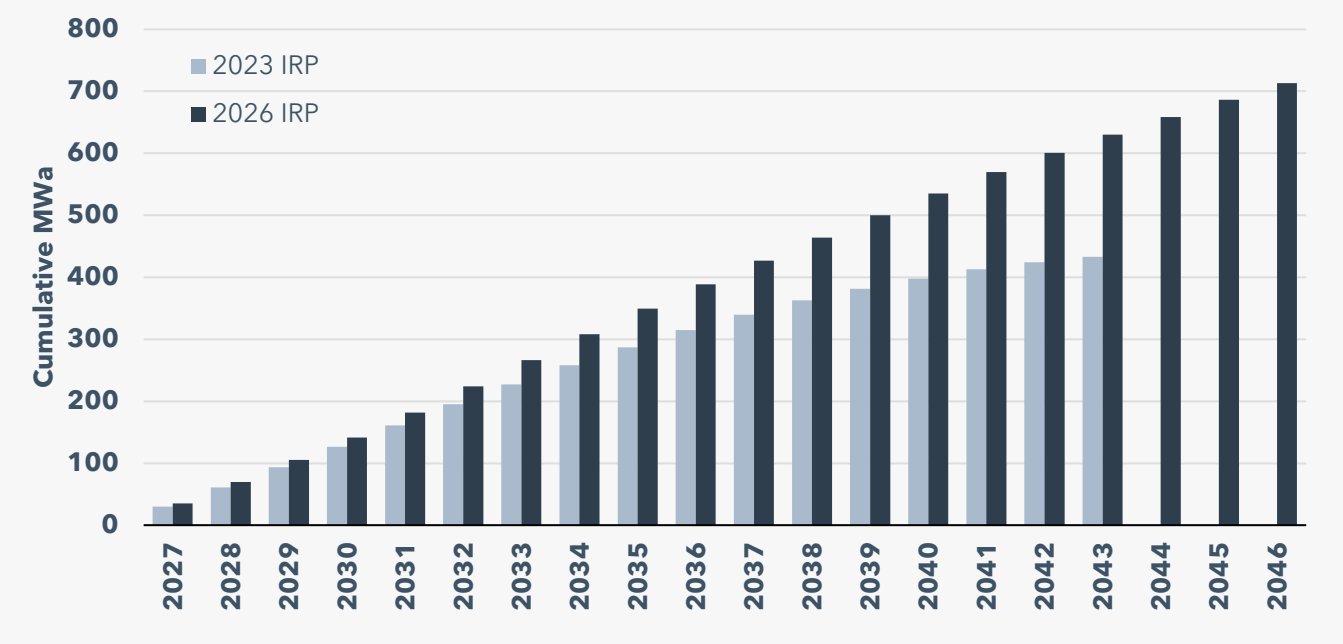


Table 14 provides the breakdown of annual cost-effective EE savings assumed in this IRP load forecast through 2035.

Table 14. Cost-Effective Energy Efficiency Savings Breakdown by Year, Sector, and Program

Sector	Program	2027	2028	2029	2030	2031	2032	2033	2034	2035
Commercial	Existing Buildings	6.7	7.2	7.5	8.0	8.4	8.5	8.1	7.7	7.1
Commercial	New Buildings	5.5	5.9	6.2	6.4	6.4	6.4	6.2	6.1	6.2
Industrial	Industrial	9.1	9.5	9.8	10.2	10.6	11.0	11.2	11.4	11.5
Business Lighting	C&I Lighting	7.5	7.5	7.3	7.3	7.6	7.3	6.2	4.7	3.3
C&I Total		**28.9**	**30.0**	**30.9**	**32.0**	**33.0**	**33.1**	**31.7**	**29.9**	**28.1**
Residential	Existing Homes	5.4	5.3	5.9	5.4	8.8	10.6	11.9	13.1	14.2
Residential	New Homes	1.1	0.9	0.9	0.6	0.6	0.6	0.7	0.7	0.7
Residential Total		6.5	6.3	6.8	6.0	9.4	11.2	12.5	13.8	14.9
Yearly Total		**35.3**	**36.3**	**37.6**	**38.0**	**42.5**	**44.3**	**44.2**	**43.7**	**43.0**

As ETO increasingly determines EE measures to be cost-effective, the tariff charge and spending budget collected through rates will also increase.[97]

[97] For more information, see Energy Trust of Oregon, 2026-2030 Multiyear Plan, available at https://www.energytrust.org/wp-content/uploads/2025/12/Energy-Trust-2026-2030-Multiyear-Plan-with-financial-statements.pdf.

6.2.4.2 Non-Cost-Effective EE

In addition to cost-effective EE savings forecast, ETO also provides PGE with savings and levelized cost data for EE measures that do not pass the cost-effectiveness screening. These non-cost-effective (NCE) EE measures are bundled into five (5) discrete bins for simplified aggregated inclusion in IRP modeling and are incorporated as candidate resource options available for selection in portfolio analysis. For more information on the bundling methodology and resulting bin data, see Appendix Section G.1.

6.3 RFP Results

Since the 2023 CEP/IRP, PGE has undertaken significant procurement activity to secure the non-emitting energy and capacity needed to reliably serve growing customer demand and maintain progress toward Oregon's greenhouse gas emissions requirements. These efforts include two (2) all-source RFPs and a multi-phase Request for Offers (RFO) process for CBRE, providing PGE with substantial market intelligence on resource availability, cost, deliverability, and development risk.

6.3.1 2023 All-Source RFP

PGE initiated the 2023 All-Source RFP to acquire resources capable of entering service between 2025 and 2027. Following regulatory approval, PGE issued the RFP in February 2024 and established a final shortlist of renewable and storage resources in September 2024. Subsequent negotiations occurred during a period of significant market volatility, including changing tariff and federal tax policy, supply-chain pressures, interconnection delays, and increasing competition for viable projects. Two shortlisted projects withdrew, one following acquisition by a large customer elsewhere in the region and another because of schedule risk associated with the BPA interconnection process.

In response to these changing market conditions, and following consultation with the Independent Evaluator, PGE provided all shortlist-eligible bidders with an opportunity to update pricing.[98] This preserved competition and resulted in an Updated Final Shortlist with additional renewable resource opportunities. In parallel, PGE pursued variants of two highly ranked storage projects outside the competitive bidding process and subsequently received the necessary OPUC waivers of the competitive bidding rules to procure these resources.

Through these efforts, PGE successfully contracted for four projects that collectively represent substantial additions of renewable generation and flexible capacity and are reflected in the 2026 CEP/IRP base portfolio:

- Biglow Optimization: 125 MW of solar and 125 MW of BESS, co-located with PGE's existing Biglow Canyon wind facility, with anticipated commercial operation by the end of 2027.

[98] PGE filed the Updated Final Shortlist on Oct. 1, 2025 in OPUC Docket UM 2274: https://edocs.puc.state.or.us/efdocs/HAH/um2274hah340268114.pdf. OPUC approved CBR waivers for Meadowlark and Nottingham BESS projects via OPUC Dockets UM 2418 and UM 2431 respectively.

- Wheatridge Expansion: 240 MW of solar and 125 MW of BESS, co-located with the existing Wheatridge renewable energy facility, with anticipated commercial operation by the end of 2027.
- Meadowlark BESS: 200 MW of BESS in Oregon, with anticipated commercial operation by the end of 2027.
- Nottingham BESS: 200 MW of BESS in Oregon, with anticipated commercial operation by the middle of 2028.

Together, these acquisitions demonstrate PGE's ability to translate IRP-identified needs into executable projects while adapting procurement strategies to rapidly changing market conditions. They also provide important lessons for continuing planning and procurement: resource availability cannot be evaluated on cost alone. Deliverability, interconnection readiness, permitting, tax-credit qualification, supply-chain exposure, development maturity, and competition from other buyers increasingly determine whether an otherwise attractive resource can be delivered for customers.

6.3.2 2025 All-Call PPA Solicitation

In parallel with the 2023 All-Source RFP price refresh, PGE undertook a broader 2025 All-Call for PPAs to test the market for additional near-term renewable resources that could supplement the RFP portfolio and support PGE's identified energy, capacity, and emissions-reduction needs. This provided an additional pathway for projects that had not participated in, or advanced through, the 2023 RFP to demonstrate whether executable opportunities remained available in the market.

PGE evaluated responses with a focus on both economics and executability, including development maturity, interconnection and transmission status, permitting, commercial terms, tax-credit eligibility, and the ability to achieve required commercial operation timelines. PGE reviewed seven unique projects through this process, only a subset of which were additional to projects previously considered by PGE. All projects reviewed ultimately faced significant viability and timeline risks, leading PGE to determine that they could not be executed on acceptable terms and timelines.

While this process did not result in additional resource acquisitions, it provided important market validation. Conducted contemporaneously with the 2023 RFP price refresh, the results demonstrated that the challenges encountered in the RFP were reflective of broader market conditions rather than limitations of the competitive procurement itself. Viable near-term renewable projects were increasingly constrained by interconnection and transmission delays, development timelines, changing tax and tariff conditions, and competition from other buyers.

The results also reinforced that the 2023 All-Source RFP had successfully captured a substantial portion of the viable resource opportunities available to PGE for the relevant delivery period. Taken together, the RFP and All-Call demonstrate an increasingly important consideration for the 2026 CEP/IRP: the availability of economically attractive generation does not necessarily translate into the availability of executable resources. Future procurement strategies must therefore consider development maturity, deliverability, timing, and competitive market dynamics alongside modeled resource needs and price.

6.3.3 2025 All-Source RFP

PGE initiated the 2025 All-Source RFP to address significant energy and capacity needs identified in its resource planning and to continue progress toward Oregon's clean energy requirements. Issued in July 2025, the technology-neutral solicitation sought a broad range of resources and commercial structures, including renewable generation, energy storage, PPAs, storage capacity agreements, build-transfer agreements, and hybrid structures. An Independent Evaluator oversaw the process to support fair and transparent competitive procurement.

The RFP received a strong market response, materially larger than the prior procurement cycle, and demonstrated substantial developer interest in serving PGE customers. Following competitive evaluation and a best-and-final-offer process, PGE filed a final shortlist in February 2026 consisting of twelve non-emitting projects totaling approximately 4,800 MW of wind, solar, and battery storage, with anticipated commercial operation dates from 2028 through 2030. [99] The shortlist was intentionally larger than PGE's approximately 2,500 MW contracting objective to preserve flexibility and account for the possibility that not every project would ultimately reach execution.

As PGE moved from acknowledgment toward execution, a convergence of development risks, none within the Company's or its bidders' control, emerged as the defining feature of the current procurement environment. These risks align with the evolving planning environment described in Chapter 3 (specifically, Section 3.2) and explain why the expected realization rate from the shortlist is roughly half of its nameplate capacity, and why continued reliance on a single RFP process introduces challenges to addressing the IRP identified energy and capacity needs. This supports PGE's multi-pronged approach to resource procurement. Shortlisted projects have been particularly impacted by one or more of the following factors:

Federal FAA obstruction permitting: The U.S. Department of Defense ceased forwarding wind-project reviews to the Federal Aviation Administration, which must issue a Determination of No Hazard before turbines may be constructed. This federal action stalled many onshore wind projects nationally and placed the shortlist's approximately 1,000 MW of wind at risk, with no certain timeline for resolution. Because wind is an important contributor to winter energy and portfolio diversity, this exposure is material to PGE's planning.

BPA interconnection and firm transmission availability: Most shortlisted renewables interconnect to or wheel across the Bonneville Power Administration system, where cluster-study timelines and network-upgrade outcomes gate the largest projects. Compounding this, long-term firm transmission is scarce: most initially shortlisted renewable bids offered no incremental long-term firm transmission and relied instead on non-firm or conditional-firm products, which weaken firm deliverability during constrained conditions. Interconnection and transmission progress remain unresolved for a substantial share of shortlist capacity.

Competition from datacenters and other large loads: Rapid regional demand growth driven substantially by datacenters has created a class of large-load buyers able to acquire renewable and storage projects on terms a regulated utility cannot match. Because these buyers are not bound by

[99] See PGE's Request for Final Shortlist Acknowledgement, filed to Docket UM 2371 on 17 Feb 2026 (3 Apr 2026 errata): https://edocs.puc.state.or.us/efdocs/HAH/um2371hah345181028.pdf.

regulated procurement timelines, they can absorb the price changes and construction delays that the FAA and transmission uncertainties are now imposing. This dynamic has already affected PGE's procurement, with at least one shortlisted project withdrawing after acquisition by a competing off-taker.

In the context of continuing uncertainty about negotiation outcomes, IRP analysis does not embed an assumption of specific outcomes. Instead, PGE's base portfolio assumptions account for executed projects only. 2025 RFP projects are available for selection in capacity expansion modeling, as described in Appendix Section H.6.6. PGE's approach to 2025 RFP negotiations and other procurement actions moving forward is described in Section 2.1.2.

6.3.4 CBRE RFO

In parallel with its utility-scale resource procurements, PGE initiated a Request for Offers (RFO) in late 2024 to acquire Community-Based Renewable Energy (CBRE) resources consistent with the 2023 CEP/IRP Action Plan. Because CBRE represents a developing resource category with different project sizes, developers, and community objectives than traditional utility-scale procurement, PGE designed a flexible process intended to broaden participation while maintaining competitive discipline and a clear focus on customer value.

The RFO included multiple procurement rounds, bidder feedback, and opportunities to refine proposals. This iterative approach helped projects mature through the procurement process while allowing PGE to evaluate both system value and community benefits. In March 2026, PGE identified a shortlist of 14 projects representing nearly 50 MW of on-system solar and storage resources.

Negotiations remain underway, and no CBRE projects are assumed in the 2026 CEP/IRP base portfolio. However, the RFO provided important market intelligence regarding the cost, availability, development maturity, and characteristics of CBRE resources. These results inform the CBRE resource potential and proxy cost assumptions used in the 2026 IRP analysis, as described in Appendix Section G.3.

More broadly, the RFO demonstrates PGE's approach to developing new resource pathways: creating opportunities for emerging resource categories while maintaining disciplined evaluation of cost, executability, system value, and customer and community benefits.

PGE remains supportive of continued development of CBRE resources as part of Oregon's clean energy transition. Experience from PGE's initial CBRE procurement demonstrates that smaller, community-based projects can provide benefits, including local resilience, community ownership and participation, workforce and economic development, and benefits targeted to historically underserved communities.

At the same time, CBRE resources are generally smaller and can be more expensive on a per-unit basis than utility-scale alternatives. As CBRE deployment increases, customer price impacts should therefore become an explicit consideration in determining the appropriate pace, scale, and structure of additional procurement. The objective should be to develop community-centered CBRE projects where incremental community and system benefits justify the incremental cost.

The next phase of CBRE development should be built on the foundation established through PGE's initial RFO and the work of the CBIAG, while evolving toward a more community-led and affordability-focused model. PGE can provide procurement pathways, technical expertise, system-value analysis, and a potential long-term offtake; communities and project sponsors can increasingly lead the identification of desired benefits, project partnerships, and external funding.

This approach creates an important discipline: the incremental cost of CBRE should be matched by incremental value or reduced through external funding. Where a project costs materially more than an equivalent utility-scale resource, the first question should be whether grants, incentives, community capital, or other funding can buy that cost down toward market—not whether the premium should automatically be borne by all customers.

An effective CBRE framework should seek to maximize community benefits while minimizing costs, recognizing that affordability is itself a benefit shared by all customers and that cumulative procurement decisions, rather than any single project, ultimately determine customer costs. Done well, CBRE procurement may be able to grow while maintaining affordability, strengthening community ownership of project outcomes, and delivering measurable community benefits alongside meaningful system value for the customers who ultimately fund these investments.

6.4 New Resource Energy Values

PGE analyzed a range of new resource options in this CEP/IRP to reflect different resource types, locations, capabilities, and technological advancements. For more detail on each new resource type option and economic assumptions, see Appendix G.

PGE uses the PGE Zonal Model (PZM) to estimate the economic dispatch of existing generation resources, contracts and potential new resources using electricity prices and associated risk variable inputs from each price future. Economic dispatch leads dispatchable resources to generate when their dispatch costs are less than the market electricity price, subject to all modeled operational constraints. The PZM methodology is outlined in Appendix Section H.2.2.

Table 15 summarizes the Reference Case energy value and range of outcomes across the simulated price futures for each resource. These values are presented on a levelized basis, across each resource's economic life, for representative resources with 2028 commercial operation dates.

Table 15. New Resource Option Energy Values (2029 COD)

Resource	Levelized Energy Value (2026$/MWh)	
	Reference Case	Range
Christmas Valley Solar	$34.42	$27 - $46
McMinnville Solar	$32.48	$26 - $44
Wasco Solar	$31.97	$25 - $43
Nevada Solar	$38.11	$30 - $50
Gorge Wind	$46.76	$37 - $58
Montana Wind	$55.36	$44 - $68

Resource	Levelized Energy Value (2026$/MWh)	
	Reference Case	Range
Southeast Washington Wind	$51.62	$41 - $64
North Dakota Wind	$54.56	$43 - $67
Christmas Valley Hybrid	$46.37	$37 - $59
McMinnville Hybrid	$46.10	$37 - $59
Southeast Washington Hybrid	$50.91	$40 - $63
Gorge Hybrid	$45.36	$36 - $57
Montana Hybrid	$52.97	$42 - $65
North Dakota Hybrid	**$53.24**	**$42 - $66**

6.5 New Resource Capacity Contributions

To fill the capacity needs described in Section 6.6.1.2, new resources are accredited to determine how much effective capacity they contribute to PGE's system. PGE conducts an effective load-carrying capability (ELCC) study for each new resource using Sequoia. The ELCC study is an extension of loss-of-load-probability modeling which models chronological grid operations and correlations in supply and demand across many weather years.[100] This study allows PGE to forecast a resource technology's ability to support system reliability during hours of greatest risk. For more information on PGE's loss of load probability model Sequoia see Appendix Section H.5, and for more detail on PGE's capacity accreditation methodology see Appendix Section G.6.

The 2026 IRP tests resource ELCCs in the year 2032, the end of the Action Plan window. ELCCs for portfolio expansion are calculated with a system deficit, referred to as untuned. PGE also runs an ELCC study that includes the HB 2021 Preferred Portfolio as part of the base system, called tuned ELCCs. The tuned ELCC study estimates the marginal ELCC of resources in a system inclusive of energy and capacity interactions from a highly decarbonized portfolio. For more information on tuned and untuned ELCCs see Appendix Section G.6. Table 16 displays untuned system ELCCs values for a marginal addition of each resource considered for selection in portfolio expansion. Some ELCC values are greater than 100% due to capacity and energy interactions captured in loss of load probability modeling. For more discussion on resource interactions in loss of load probability modeling, see Section 7.11.

[100] https://www.esig.energy/wp-content/uploads/2022/12/ESIG-Redefining-Resource-Adequacy-2021-b.pdf

Table 16. Untuned System ELCCs Values

Resource Group	Resource Name	Summer	Winter
Dispatchable	Combined-cycle Combustion Turbine	99%	105%
Dispatchable	Emerging Dispatchable Clean Technology	99%	105%
Dispatchable	Single-cycle Combustion Turbine	103%	100%
Energy Efficiency	Non-Cost-Effective Energy Efficiency – Bin 1	110%	110%
Energy Efficiency	Non-Cost-Effective Energy Efficiency – Bin 2	110%	110%
Energy Efficiency	Non-Cost-Effective Energy Efficiency – Bin 3	110%	110%
Energy Efficiency	Non-Cost-Effective Energy Efficiency – Bin 4	110%	110%
Energy Efficiency	Non-Cost-Effective Energy Efficiency – Bin 5	110%	110%
Flexible Load[101]	Demand Response - Bin 1	42%	34%
Flexible Load	Demand Response - Bin 2	62%	30%
Flexible Load	Demand Response - Bin 3	44%	26%
Flexible Load	Demand Response - Bin 4	41%	28%
Flexible Load	Demand Response - Bin 5	36%	30%
Other	Community-based renewable energy	78%	30%
Other	Distributed System Generation	98%	98%
Other	Optimization of Existing Wind Generation	33%	16%
Other	Repower of Existing Wind Generation	7%	3%
Solar	Christmas Valley Solar	30%	28%
Solar	McMinnville Solar	40%	12%
Solar	Nevada Solar	28%	22%
Solar	Small-Scale Renewable	30%	28%
Solar	Wasco County Solar	31%	9%
Solar Hybrid	Christmas Valley - Solar: Storage (1:1)	46%	24%
Solar Hybrid	McMinnville - Solar: Storage (1:1)	46%	25%
Storage	Lithium Ion Battery (4-hour)	45%	23%
Storage	Lithium Ion Battery (6-hour)	63%	28%
Storage	Long-Duration Storage (100-hour Iron Air)	103%	95%
Storage	Pumped Storage Hydro (10-hours)	67%	45%
Wind	Gorge Wind	35%	25%
Wind	Montana Wind	18%	51%
Wind	North Dakota Wind	32%	41%
Wind	Off-Shore Wind	50%	42%

[101] The bins for VPP Flexible Load are described in Appendix G Resource Options, Appendix Section G.2.3.

Resource Group	Resource Name	Summer	Winter
Wind	Southeast Washington Wind	22%	47%
Wind	Wyoming Wind	23%	49%
Wind Hybrid	Gorge Hybrid - Wind: Solar: Storage (1:0.67:0.67)	72%	37%
Wind Hybrid	Montana Hybrid - Wind: Solar: Storage (1:0.67:0.67)	72%	57%
Wind Hybrid	North Dakota Hybrid - Wind: Solar: Storage (1:0.67:0.67)	69%	63%

6.6 Portfolio Construction Futures

In this analysis, a Future represents a set of external system conditions used to evaluate the performance and risk of a given portfolio scenario. The scenarios assessed in portfolio analysis use these Futures to represent the range of potential conditions under which those scenarios may perform. Evaluating portfolio scenarios across a diverse set of Futures provides a means to assess the cost and risk associated with each strategy under a range of potential future conditions rather than relying on a single forecast of future system conditions. For more description of the relationship between Scenarios and Futures see (Section 7.2).

When System Needs, Market Price, and Technology Cost Futures are considered together, they represent a broad range of potential conditions that could influence the timing, magnitude, and type of resource additions needed to maintain a reliable and cost-effective system.

Figure 39 displays the hierarchy of relationships for the Need, Price, and Technology Cost Futures. Need futures are defined by Low (L), Reference (R), High (H) assumptions, representing uncertainty in the load forecast and its effect on capacity and renewable energy requirements (see Section 6.6.1). A Price Future captures uncertainty in future revenue streams of a resource investment and is defined by four subcomponents, Load, Carbon, Gas, and Resource buildout, all which have Low, Reference, and High cases, save for Resource buildout (See 6.6.2 WECC Price futures). Technology Cost futures capture uncertainty in the costs associated with resource procurement as technology economics evolve across time (See Section 6.6.3 - Energy Technology Cost Futures). Table 17 below summarizes how the System Needs Future combine with the Market Price Futures, and Technology Cost Futures resulting in the 333 unique Futures evaluated for each portfolio scenario.

Figure 39. Structure of Futures

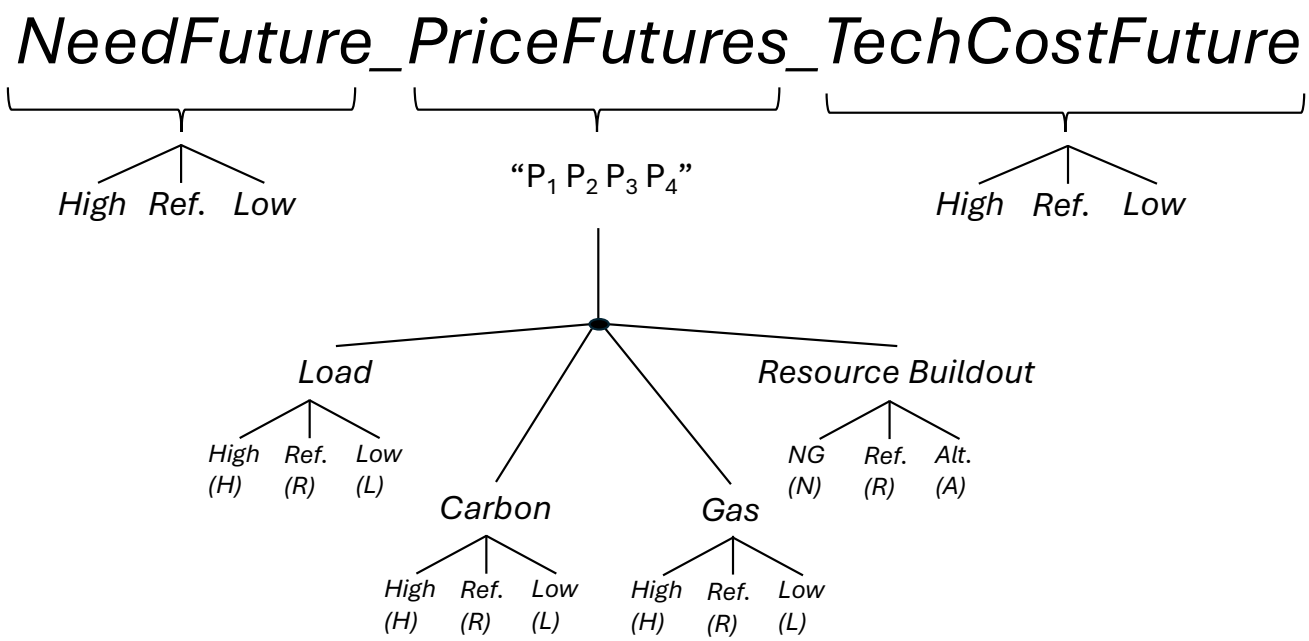


Table 17. Number of Futures Evaluated in Portfolio Analysis

	Need Futures	Market Price Futures	Technology Cost Futures	Total Futures Evaluated
Number of Futures	3	37	3	333

The following sections discuss how Futures are used in portfolio analysis, while Appendix H provides further discussion of the modeling framework, assumptions, and relationships among the models used in the analysis.

6.6.1 Need Futures

System needs (Needs) are one of three (3) components used to represent uncertainty in Portfolio Construction. Needs represent uncertainty in the magnitude and timing of PGE's future resource requirements and capture a range of load growth, electrification, and large-load development assumptions. While Market Price Futures capture uncertainty in regional market conditions and Technology Cost Futures reflect uncertainty in the cost and availability of resource technologies, Need Futures. When combined, these Future dimensions create the range of planning conditions used to evaluate portfolio scenarios. Assessing portfolios across these combinations enables PGE to identify resource strategies that remain reliable, cost-effective, and resilient under a broad range of potential future outcomes.

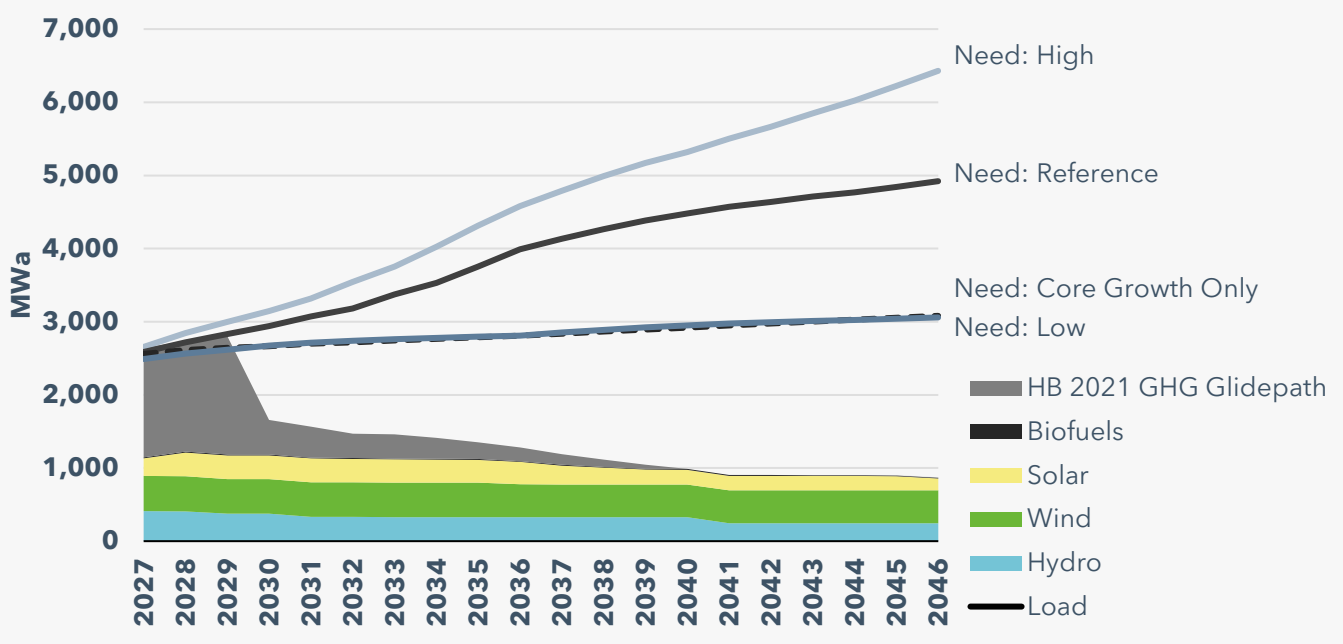
System needs are constraints that must be met during capacity expansion modeling. They are quantitative measures representing reliability, decarbonization, and other policy objectives pertaining to PGE's 2026 CEP/IRP resource plan. These measures drive resource procurement in the optimization of a least-cost, least-risk portfolio. The section below describes the four measures of system needs used in the 2026 CEP/IRP: Energy Need, Capacity Need, RPS Need, and Flexibility Need.

6.6.1.1 Energy Need

This section summarizes PGE's resource needs through the lens of energy, discussed in terms of average megawatts (MWa) or megawatt hours (MWh).[102, 103] For more information on detailed methodology, see Appendix Section H.9. The energy-load resource balance is estimated as the difference between the forecasted demand and supply. Figure 40 summarizes the amount of allowable energy that can be used to serve Oregon retail load in the reference HB 2021 GHG Glidepath scenario. This is based on the base existing portfolio prior to any incremental resource additions from portfolio analysis. Supply includes known resource contracts, new and expiring, as of the time of this IRP publication. The gap between load forecast and the stacked area of annual energy from PGE's base portfolio retained to serve retail load under GHG Glidepath assumptions represents the minimum energy need remaining to be filled by incremental additions. Because the entirety of PGE's HB 2021 GHG emissions budget is allocated through the dispatch of owned thermals and energy from contracts and purchases with associated GHG emissions, the future gap shown between load and allowed energy would need to be bridged with non-emitting resources.[104]

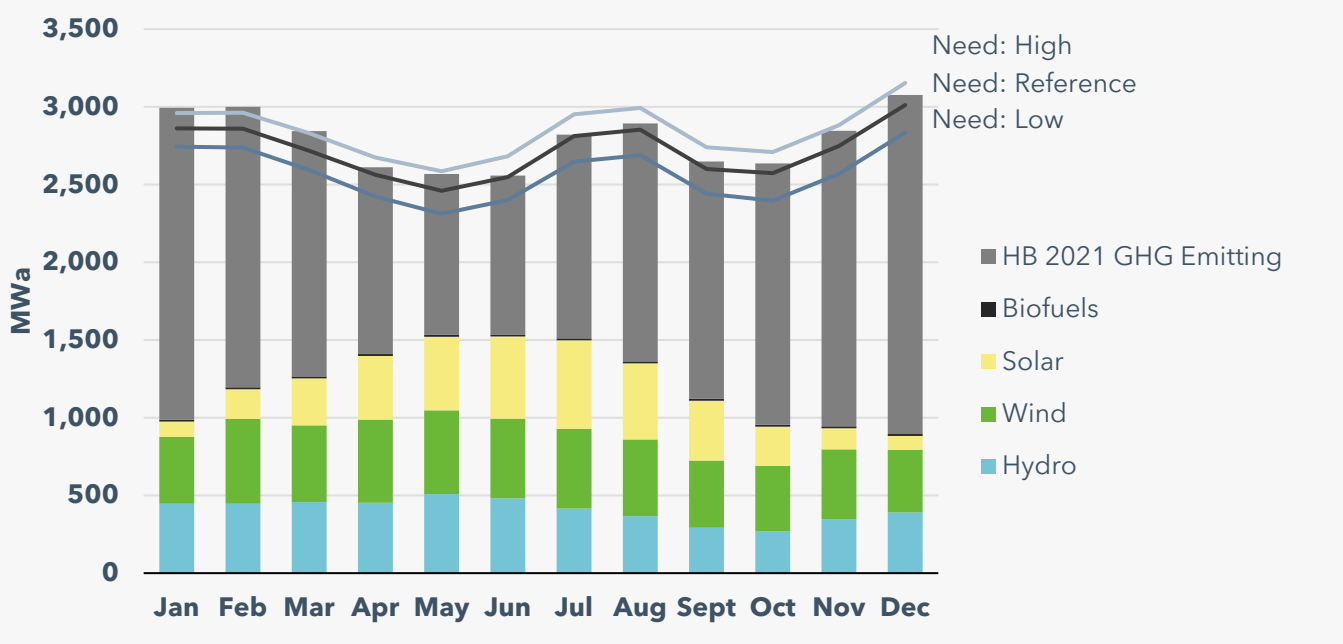
[102] One megawatt (MW) is equal to one million watts. One megawatt delivered continuously 24 hours a day for a year (8,760 hours) is called an average megawatt (MWa).
[103] One megawatt hour (MWh) is equal to one thousand kilowatts of electricity used continuously for one hour.
[104] The scenario discussed assumes no change in the emissions rate used to account for GHG emissions associated with market purchases, which aligns with the emission rate for unspecified sources, as required by ODEQ.

Figure 40. Energy-Load Resource Balance in Reference HB 2021 GHG Glidepath Scenario



A monthly energy-load resource balance is shown for 2028 in Figure 41 to further illustrate 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. The quantity of energy from existing renewable resources is calculated using monthly average capacity factors, which represent the percent of the time that a facility is expected to be generating throughout a given month. Energy from dispatchable resources is not estimated using static average capacity factors but rather informed by the timing of their generation determined by economic and operational decision making, as estimated in PZM simulation.

Figure 41. 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.

6.6.1.2 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 simulates chronological grid operations at an hourly granularity, capturing interactions between energy and capacity to estimate capacity need under a "1 event day in 10 years" reliability metric. For detailed information on inputs and assumptions used in Sequoia see Appendix Section H.5. Table 18 shows seasonal capacity needs by Future for key planning years. These values show an approximately plus/minus 50% range of capacity need by the end of the Near-term Action Plan window in year 2032.

Table 18. Comparison of Seasonal Capacity Need by Future in Key Planning Years

	2027			2030			2032			2035			2040		
	Low	Ref.	High	Low	Ref.	High	Low	Ref.	High	Low	Ref.	High	Low	Ref.	High
Summer	47	220	451	316	728	1231	555	1197	1877	894	2193	3083	2982	4964	6259
Winter	1	1	146	194	543	878	397	960	1471	742	1805	2522	2746	4491	5575

The remainder of this section summarizes the reference capacity need across the planning horizon, highlights relevant information about the potential frequency and severity of supply shortages, and considers climatic and supply drivers of risk. Appendix Section H.9 discusses how capacity needs are derived, compares capacity need across different need Futures, and presents a view of capacity need without growth from new large loads. For detailed information on capacity needs used in the State Reliability Metrics portfolio sensitivity see Appendix Section H.10.

The 2026 CEP/IRP estimates capacity need in summer (April-September) and winter (October-March). Figure 42 shows PGE's seasonal capacity need across the 20-year planning horizon with values for 2027-2035 detailed in Table 19.

Figure 42. 2027-2046 Seasonal Capacity

Table 19. 2027-2035 Yearly Seasonal Capacity

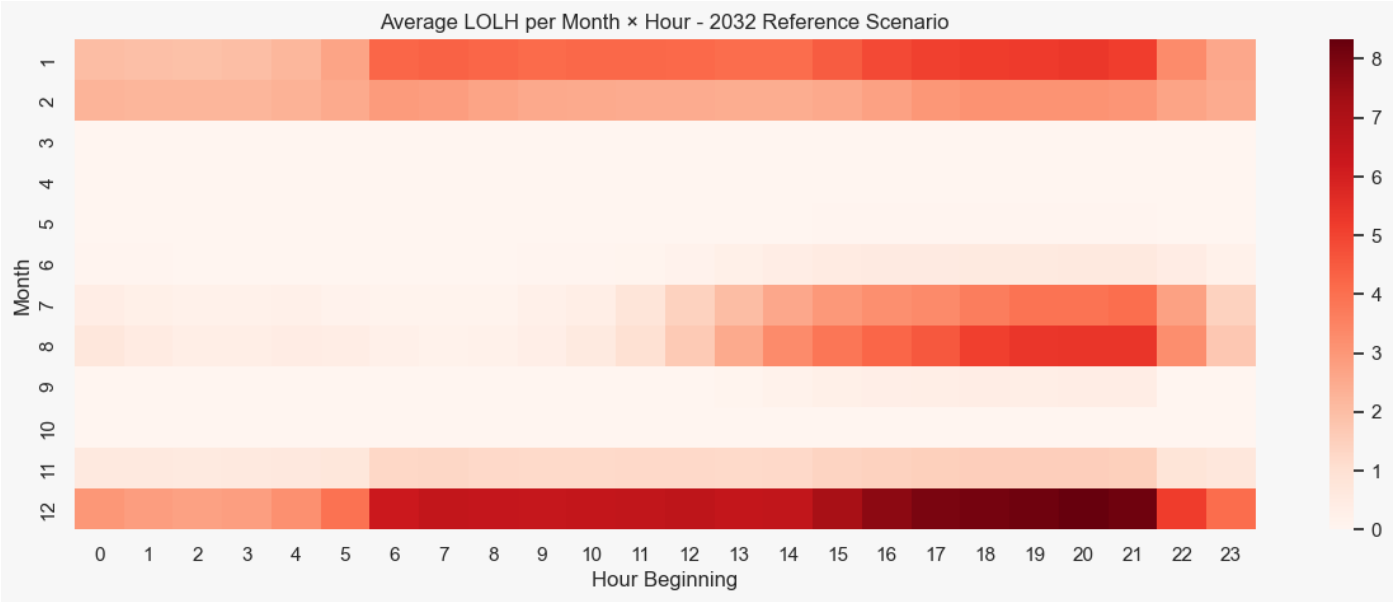
	2027	2028	2029	2030	2031	2032	2033	2034	2035
Summer	220	86	295	728	1013	1197	1489	1669	2193
Winter	1	1	129	543	791	960	1152	1369	1805

PGE's system has a 2027 summer capacity need of 220 MW in summer while the winter has 1 MW of remaining need. This summer need drops by 134 MW in 2028 with the entrance of the 2023 RFP projects. PGE can address remaining short-term need through commercial agreements to access resources, including structured or bilateral contracts. Looking beyond the short-term, capacity need

in both seasons increase significantly in 2030 due to the assumed exit of Colstrip and continued load growth. Capacity need grows steadily until 2035, where the exit of the HRCO Calpine call option causes another step change in both winter and summer need. Need continues to increase relatively linearly until 2040 when it is assumed thermals exit the portfolio due to HB 2021 emissions reductions, resulting in approximately 2 GW of increased need.

Capacity need is an annual statistic which captures seasonal system risk for a given year. However, risk is not spread equally over all months and hours of the season. Figure 43 shows a heatmap of how unserved energy risk is spread across the year 2032 based on seasonal Sequoia runs.

Figure 43. Heatmap of Unserved Energy Risk in 2032



This heatmap emphasizes two (2) distinct seasonal risk profiles: summer and winter. Summer risk during the months of July and August, where unserved energy observations are concentrated during hours beginning 18:00 through 21:00. These summer events are characteristic of high heat events where generation from solar resources subsides and net load remains high into the night-time hours due to cooling demand. With no new resource additions, hour-beginning 19:00 in August 2032 is estimated to have approximately 4 hours of unserved energy on average. Second, the heat map highlights a pronounced winter risk from December through February where unserved energy is greatest between the morning and evening peaks and spreads into the late evening and early morning hours. These winter events are driven by sustained cold weather conditions that exhaust energy in the system. With no resource additions, hour-beginning 19:00 in August 2032 is estimated to have approximately 8 hours of unserved energy on average.

Figure 44 and Table 20 expand upon the seasonal risk profiles discussed above, providing statistics of frequency, size, and duration of loss of load events, defined as contiguous loss of load hours. For the 8.4 million summer hours simulated for the year 2032, 188,033 hours have unserved energy, resulting in 27,013 loss of load events with an average peak shortfall of 396 MW, duration of 7 hours, and unserved energy of 2.61 GWh. Winter loss of load hours are 3.3 times as likely, but the

season has only 1.5 times the number of events, highlighting the extended duration events seen in winter. Although the average peak shortfall is 142 MW less than summer, the average duration of 15 hours results in 1.4 times the unserved energy per event, on average.

Figure 44. Frequency, Size, and Duration of Unserved Energy Events

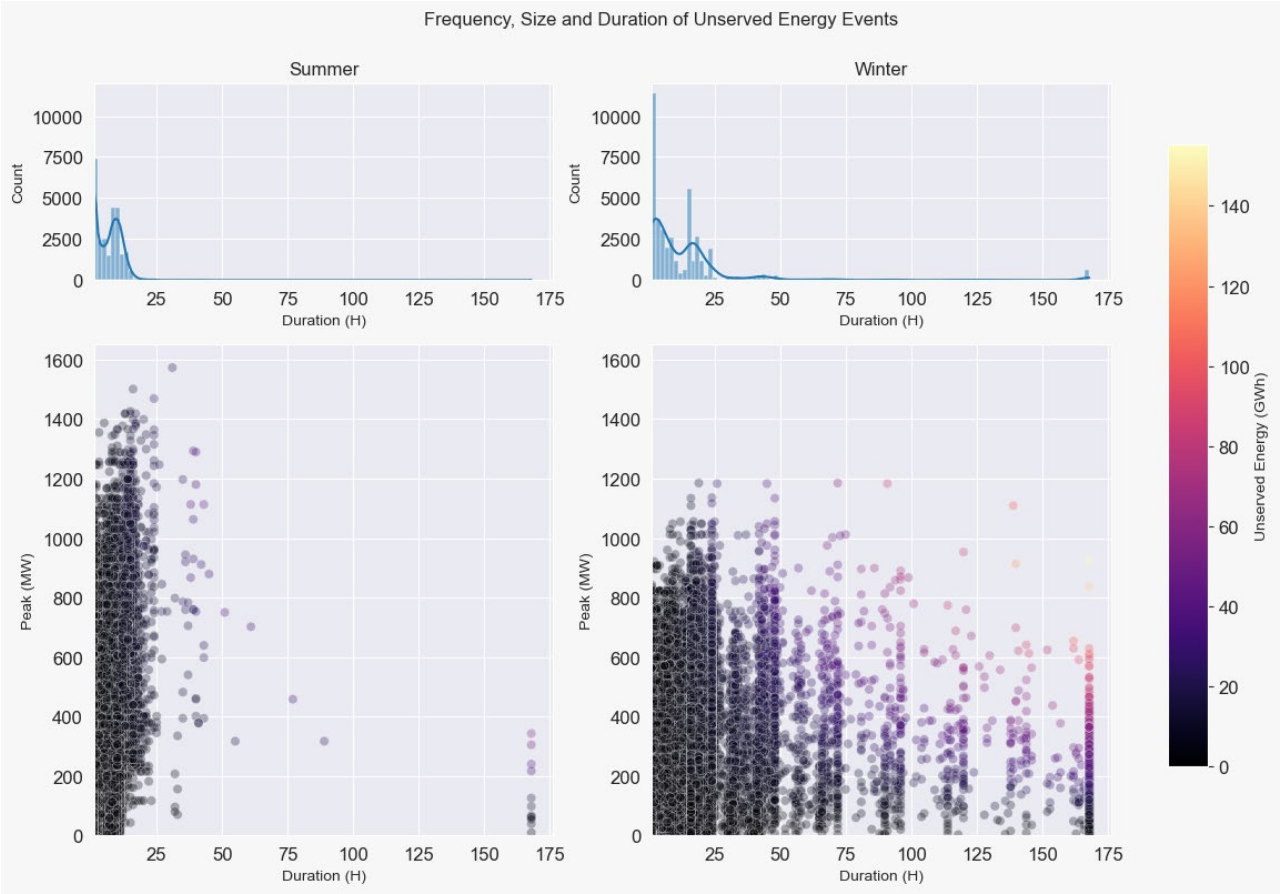


Table 20. Seasonal Risk Profiles: Sequoia Simulated Unserved Energy Events for year 2032

Metric	Summer	Winter
Unserved Energy Hours (N)	188,033	625,159
Contiguous Events (N)	27,013	41,718
Peak MW (Avg.)	396	254
Event Duration Hours (Avg.)	7	15
Unserved Energy GWh (Avg.)	2.61	3.61

Dispatch and temperature statistics from the loss of load observations suggest sustained high (low) summer (winter) temperatures are the primary driver of events with greatest unserved energy. Summer events with unserved energy above the 90th percentile average 24-hour rolling temperatures 7^{0}F above normal, with highs above 100^{0}F and overnight lows greater than 70^{0}F. These summer events last for 70 hours on average, or 3 days. The late August heat wave of 2025 is

representative of this type of extreme summer event.[105] Winter events with unserved energy above the 90th percentile average 24-hour rolling temperatures 9^{0}F below normal at 31^{0}F, with daily lows averaging 26^{0}F. These largest winter events last 144 hours on average, or 6 days. The late February 2023 cold weather storm is representative of such cold weather events.[106]

There is not a clear supply side cause of large loss of load events in either season. Rather, it is sustained high loads that exhaust the energy in the system. This energy is constrained by fuel limits, intertie transfers, hydro budgets, and renewable energy generation. These energy constraints bind during multi-day events and limit the availability for capacity to serve load during peak hours and storage capacity to recharge during off-peak.

6.6.1.3 Renewable Portfolio Standard Needs

The Renewable Portfolio Standard (RPS) was established as a law in Oregon in 2007. In 2016, Senate Bill (SB) 1547 escalated the RPS obligation for electric utilities, requiring 50% of customer demand to be met with electricity from renewable resources by 2040. Table 21 shows the RPS obligation by year and renewable needs based on the requirement as a percent of forecasted load.

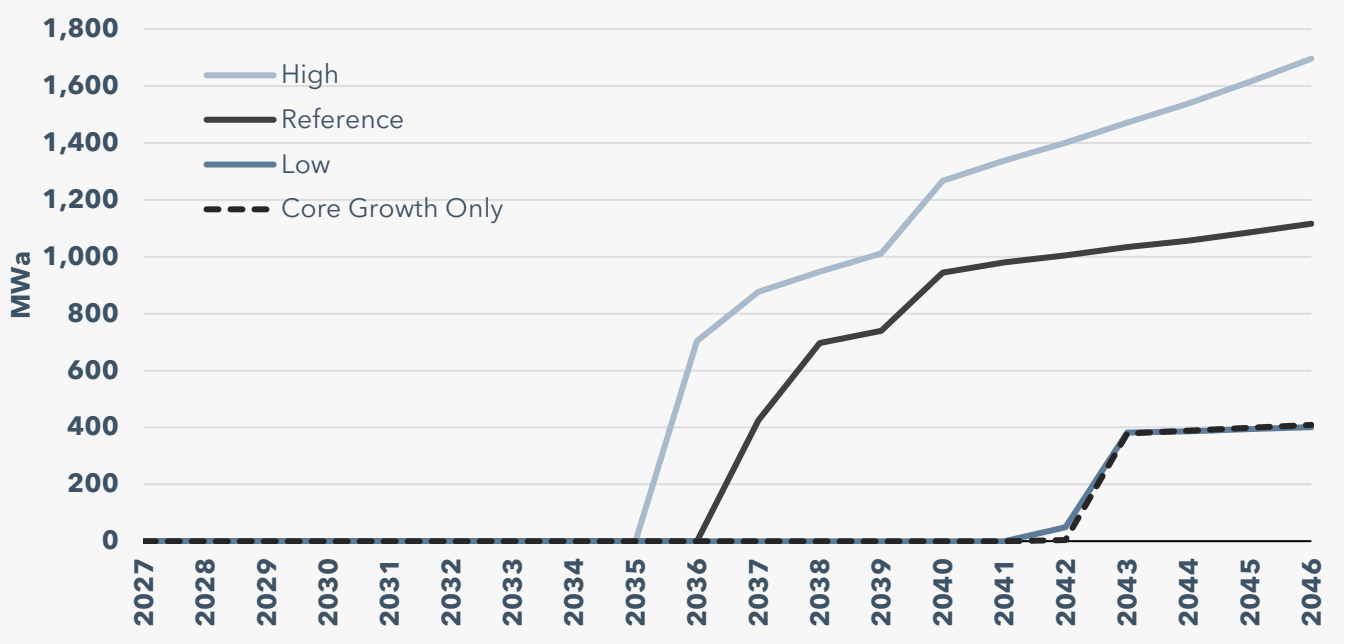
Table 21. RPS Obligation and Requirement Across Need Futures

Key RPS Year	RPS Obligation (% of retail sales)	Total Renewable Requirement for RPS (MWa)			
		Core Growth Only	Low	Reference	High
2027	27%	531	517	536	551
2030	35%	716	718	791	846
2035	45%	963	967	1,298	1,491
2040	50%	1,121	1,132	1,720	2,043

Without incremental renewable resource actions beyond what are in the existing baseline portfolio described in Appendix G, RPS obligations are projected to exceed the quantities of Renewable Energy Certificates (RECs) available from generation from existing RPS-eligible resources as shown in Figure 45. REC shortages begin soonest in the High need future, in 2036, and later in other need futures as RPS obligation and load increase over time.

[105] https://www.opb.org/article/2025/08/22/oregon-heat-weather-extreme-multnomah-county-willamette-valley/
[106] https://www.opb.org/article/2023/02/22/snow-portland-oregon-traffic-snarled/

Figure 45. RPS Shortage Across Need Futures



All portfolios are designed to comply with Oregon RPS requirements through the 20-year planning horizon. ROSE-E simulates the generation, banking, and retirement of RECs from RPS-eligible resources and enforces the five-year lifetime limit on banked RECs, consistent SB 1547. For each portfolio to meet RPS requirements in each need future, the retired RECs in each year must meet or exceed the RPS obligation in that year. The HB 2021 Preferred Portfolio, detailed in Chapter 7, follows RPS requirements, though this policy is not the binding constraint for renewable energy additions as they are driven by the more stringent HB 2021 policy needs.

6.6.1.4 Flexibility Needs

Flexibility is a measure of the system's ability to respond to unexpected deviations in load and generation forecasts.[107] Similar to past IRP's, PGE contracted Sylvan Analytics to conduct a Flexibility Study Appendix Q. One output from this study are the flexibility needs in MW of capacity required to maintain flexibility adequacy in a highly decarbonized system.

6.6.2 WECC Price Futures

PGE's 2026 CEP/IRP wholesale electricity price forecast reflects updated stronger load growth expectations, changes in federal energy policy, revised natural gas price forecasts and varying regional supply assumptions. Relative to prior IRP vintages, the forecast generally trends higher over the long term, reflecting changing expectations for electricity demand, fuel markets, and

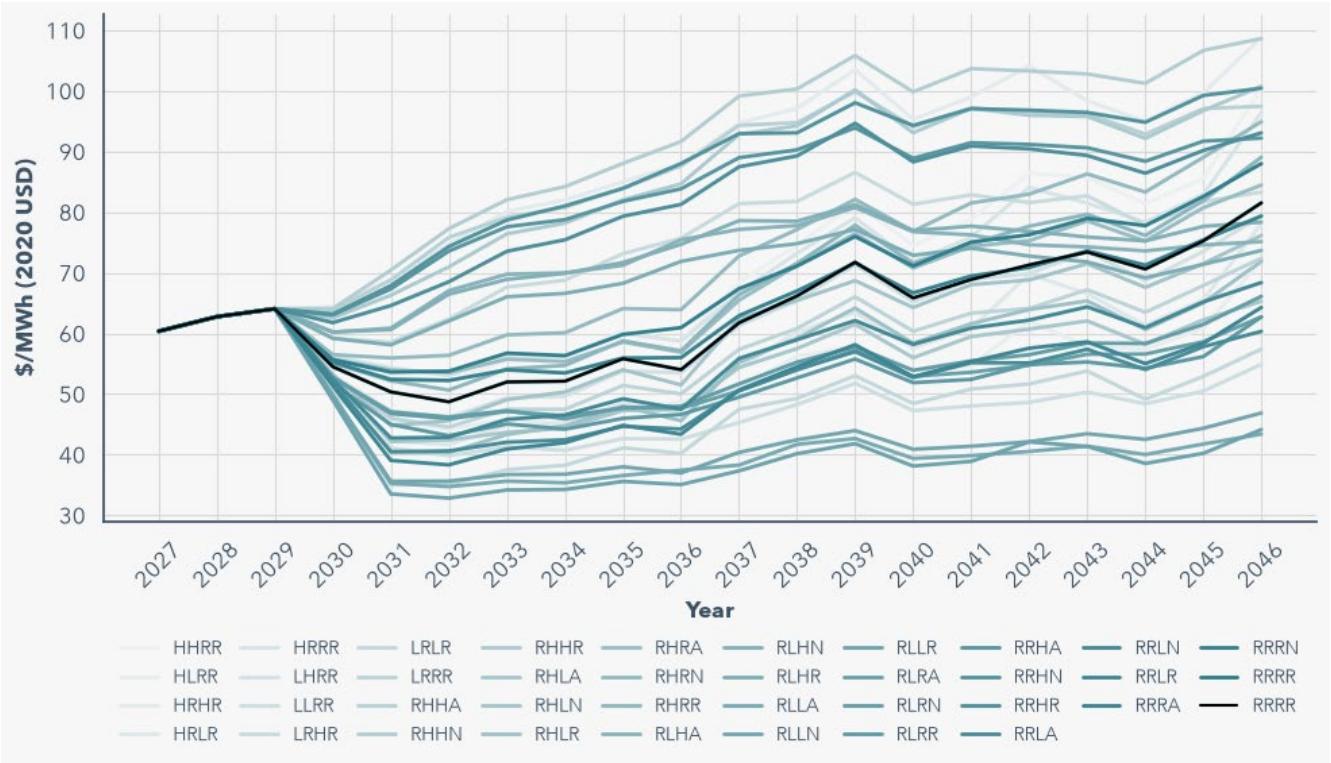
[107] Flexibility as defined in the context of the Flexibility Study does not pertain to behind-the-meter load flexibility programs.

regional resource adequacy. A discussion of the 2026 methodology can be found in Appendix Section H.2.1.

The Reference Case combines PGE's Electric Forward Price Curve (FPC) for the near term with Wood Mackenzie's long-term WECC market outlook. Near-term market prices are based on observed forward market expectations through 2029, while longer-term prices reflect modeled regional market fundamentals. The resulting forecast is used throughout the IRP to evaluate resource dispatch, market purchases and sales, and resource economics.

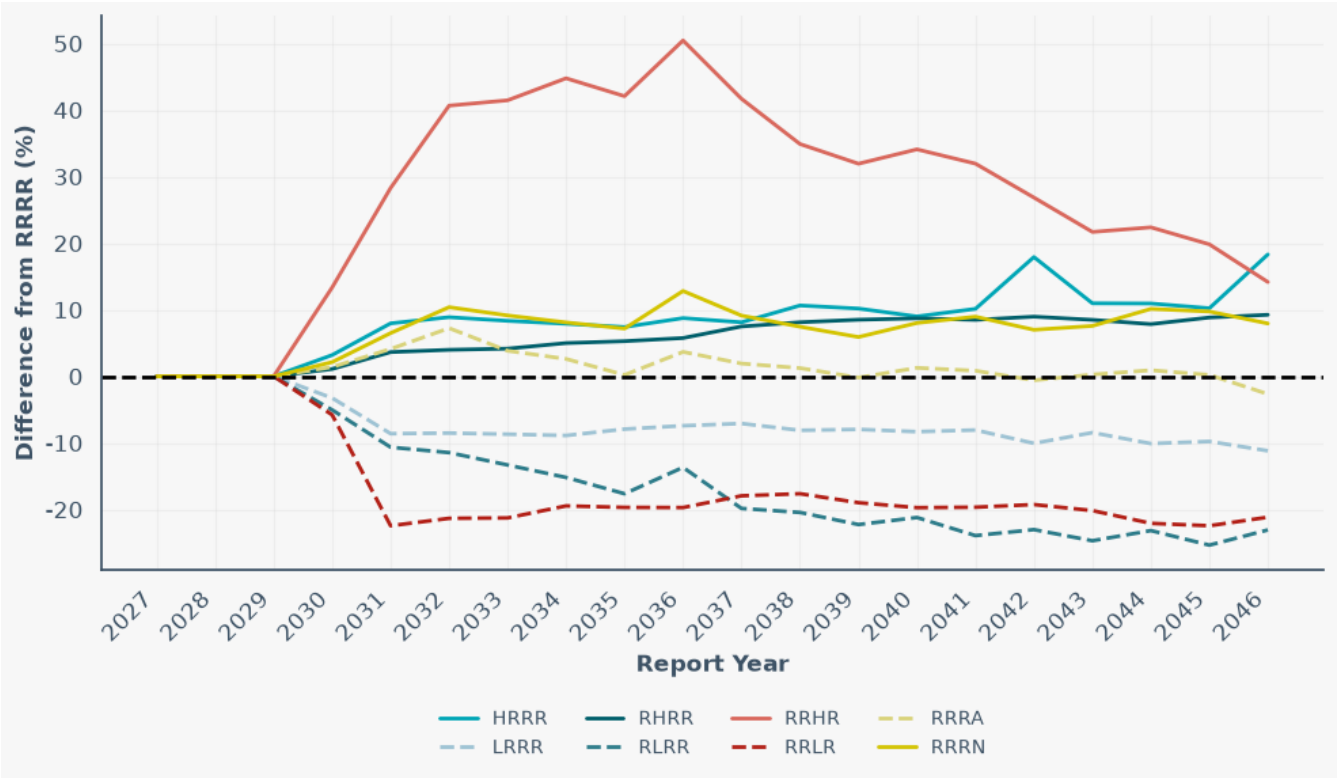
To evaluate uncertainty in future market conditions, PGE developed 37 WECC price futures by varying electric load growth, natural gas prices, carbon pricing assumptions, and regional resource development trajectories. The 37 price futures are shown in Figure 46 below. The differences[108] in the price futures for each source of uncertainty as compared to reference case are shown in Figure 47. Together, these futures produce a broad range of wholesale electricity price outcomes over the planning horizon and provide insight into how changes in regional market conditions affect future prices.

Figure 46. 37 Price Futures used in the 2026 CEP/IRP



[108] The differences discussed here are isolated to reflect the incremental change of the key driver of uncertainty and omits interactive effects between sources of uncertainty.

Figure 47. Differences from Reference Case (RRRR) Across Drivers of Uncertainty in Price Futures



6.6.2.1 Load Growth

Load growth assumptions produced some of the largest sustained deviations from the Reference Case across the WECC futures. Relative to the Reference Case, the High Load future (HRRR) increases average annual wholesale electricity prices by approximately 8-11% over most of the planning horizon, with impacts exceeding 17% in 2042 and 18% in 2046. Conversely, the Low Load future (LRRR) decreases average annual prices by roughly 7-11% throughout the study period.

Importantly, these load futures vary regional electricity demand assumptions while maintaining the same supply-side resource buildout embedded in the Reference Case. Because resource additions and retirements are not adjusted to respond to higher or lower demand levels, changes in market prices absorb much of the impact of the load variation. As a result, the modeled futures effectively evaluate the sensitivity of wholesale electricity prices to changing system load under a fixed regional resource portfolio.

Under higher load growth, increased demand reduces surplus capacity, tightens reserve margins, and increases the frequency with which higher-cost resources are dispatched, resulting in higher market-clearing prices. Under lower load growth, the opposite effect occurs as available generation serves a smaller load obligation. The results indicate that load growth uncertainty becomes increasingly influential over time, particularly in later years as the system operates with tighter supply-demand balances and greater reliance on incremental resource additions. The widening divergence between the High Load and Low Load futures, reaching a nearly 30-percentage point

spread relative to the Reference Case by 2046, demonstrates the significant sensitivity of long-term wholesale electricity prices to regional demand growth assumptions.

6.6.2.2 Natural Gas Prices

Natural gas prices produced the largest overall price variation among the futures evaluated. Relative to the Reference Case, the High Gas Price future (RRHR) increases average annual wholesale electricity prices by approximately 20-50% between 2031 and 2046, with the largest impacts occurring during the mid-2030s when annual prices exceed the Reference Case by more than 40% and peak at approximately 50% in 2036. In contrast, the Low Gas Price future (RRLR) reduces annual prices by roughly 18-22% across most years of the study horizon.

These results reflect the central role of natural gas-fired resources in setting marginal energy prices across the WECC. Because gas-fired generation frequently establishes the market-clearing price, changes in fuel costs are transmitted directly into wholesale electricity prices. Among the uncertainties evaluated, natural gas prices create the widest range of market outcomes, demonstrating the strong dependence of long-term electricity prices on fuel market fundamentals.

6.6.2.3 Carbon Pricing

Carbon pricing assumptions create moderate but persistent differences in wholesale electricity prices throughout the planning horizon. Relative to the Reference Case, the High Carbon future (RHRR) increases annual average prices by approximately 4-9%, while the Low Carbon future (RLRR) decreases prices by approximately 10-25%.

The magnitude of the downward price impact in the Low Carbon future is generally larger than the upward impact observed in the High Carbon future. This result reflects the interaction between carbon costs, resource dispatch, and the frequency with which carbon-emitting generators are marginal. By altering the variable operating costs of thermal resources, carbon allowance prices affect both dispatch patterns and market-clearing prices, producing sustained differences in wholesale market outcomes over the study horizon.

6.6.2.4 Resource Buildout

Alternative resource development trajectories create uncertainty in the effect and timing of PTC/ITC expirations on resource composition in the WECC. The different resource buildouts produced smaller changes in average annual prices than the load, natural gas, or carbon futures, but they illustrate the importance of resource composition and operational characteristics in determining market outcomes.

The Natural Gas Buildout scenario (RRRN) increases annual average prices by approximately 6-13% relative to the Reference Case beginning in 2031. The largest impact occurs during the mid-2030s, when prices are approximately 10-13% above Reference levels. These increases are primarily attributable to the higher variable operating costs associated with gas-fired generation relative to renewable resources.

The Alternative Technology Buildout scenario (RRRA), which substitutes renewable additions with nuclear and geothermal resources, has a comparatively small impact on average annual prices.

Price differences generally remain within ±4% of the Reference Case, with modest increases during the early and middle years of the study and slight price reductions emerging in several later years. These results suggest that although alternative technology choices materially alter dispatch patterns and hourly price formation, their impact on average annual prices is considerably smaller than uncertainties associated with fuel prices, demand growth, or carbon policy.

6.6.3 Energy Technology Cost Futures

The 2026 IRP evaluates capital cost uncertainty through a set of technology cost futures that reflect alternative trajectories for the fixed costs of new supply-side resources. These futures are developed using the Levelized Utility Cost Aggregator System (LUCAS), PGE's revenue requirement model used to estimate the fixed costs of utility-owned and proxy resources. Modeling details regarding LUCAS are included in Appendix Section H.3.

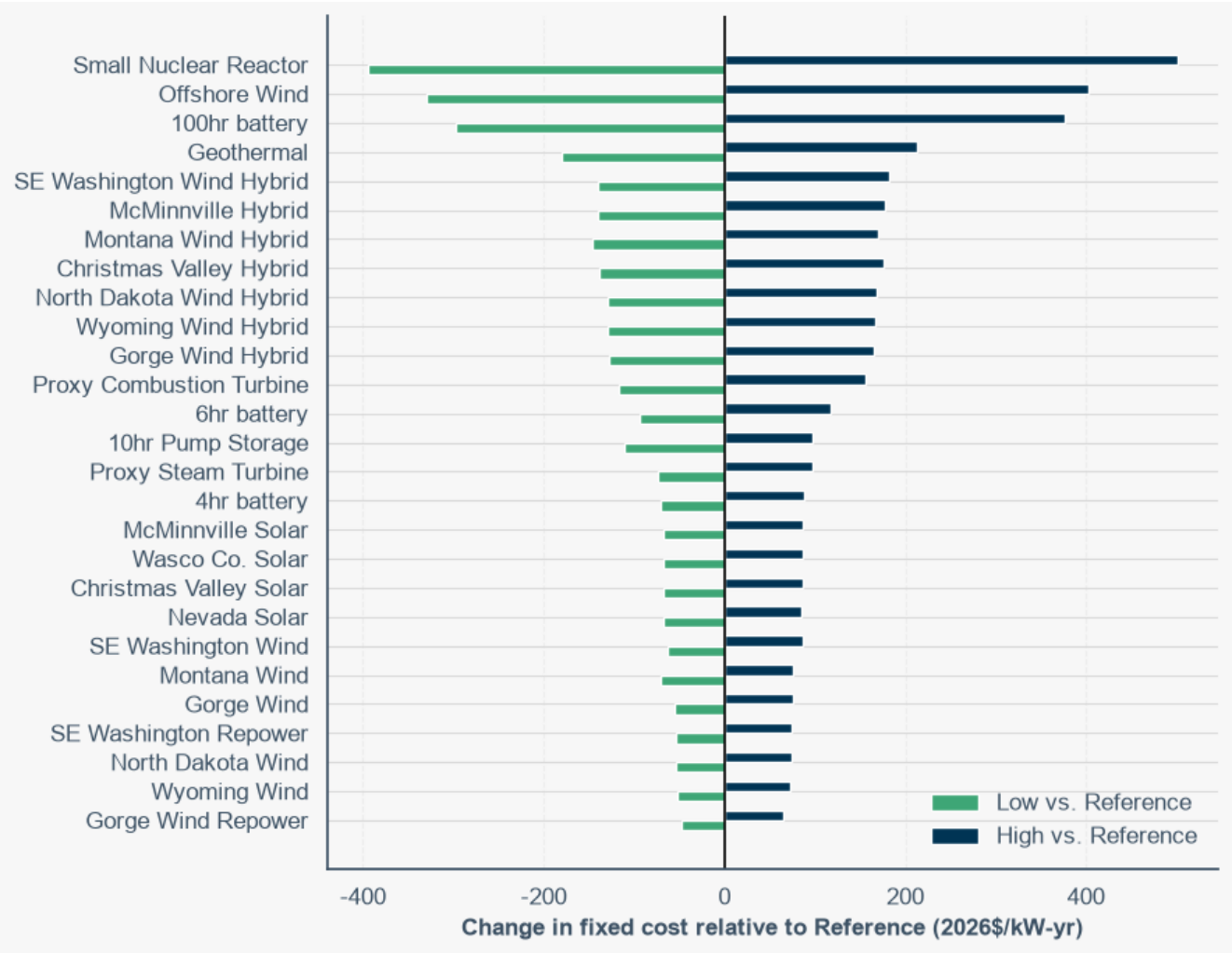
LUCAS converts resource investment assumptions into levelized fixed revenue requirements by incorporating overnight capital costs, construction financing, depreciation, taxes, tax incentives, and fixed operations and maintenance expenses. The resulting real-levelized fixed costs, expressed as dollars per kilowatt-year ($/kW-year), are provided to ROSE-E for portfolio optimization and resource selection

As discussed in Appendix Section G.5, three (3) technology cost futures provide a range of information for each proxy supply-side resource:

- Low-Cost Future: Represents a trajectory in which capital and operating costs decline more rapidly than expected due to technological and procurement improvements.
- Reference-Cost Future: Represents PGE's expected trajectory for resource costs based on current market conditions, announced projects, and available industry forecasts.
- High-Cost Future: Represents a trajectory in which resource costs are relatively elevated because of slower technological progress and procurement and supply chain constraints.

Figure 48 illustrates the fixed-cost trajectories produced by LUCAS by resource under the low-cost futures and high-cost futures compared to reference-cost futures. Differences between the futures reflect alternative assumptions regarding capital and operating expenses. These levelized fixed costs are subsequently used within ROSE-E to evaluate the comparative economics of resource portfolios.

Figure 48. Real Levelized Fixed Costs (2026 $/kW-yr) Across Tech Futures - 2030 COD



For the 2026 IRP, several updates were made to the technology cost future methodology to reflect changes in federal energy policy and evolving supply chain risks.

First, federal tax credit assumptions were updated to reflect provisions of the One Big Beautiful Bill Act (OBBBA). These updates include revised eligibility requirements, updated production tax credit (PTC) and investment tax credit (ITC) treatment, including tax credit phaseout schedules, within LUCAS. Consistent with OBBBA interpretations discussed elsewhere (please see Section 3.2.1), standalone battery storage resources achieving commercial operation by year-end 2039 remain eligible for ITC. ITC and PTC are assumed to be available only for solar and wind projects selected through PGE's 2025 RFP Final Shortlist. These projects are represented by the proxy Gorge Wind + Solar + Storage Hybrid resource, with ITC and PTC on the respective solar and wind components available for the first 1,000 MWs of the hybrid resource selected in portfolio construction that are placed in service by year-end 2030. No additional solar or wind projects are assumed to qualify for ITC or PTC benefits beyond those procurements (i.e., no stand-alone solar or wind projects, and no other hybrid configurations are assumed to benefit from the solar ITC or wind PTC) in the IRP analysis.

Second, PGE adjusted the resource cost futures to reflect uncertainty associated with domestic content and prohibited foreign entity requirements established under OBBBA. These provisions may increase development costs and constrain supply chains for certain technologies that currently rely on imported equipment or materials. To capture this risk, wind and solar technologies were assigned High-Cost Future assumptions through 2029, and battery storage technologies were assigned High-Cost Future assumptions through 2034. These adjustments reflect the potential for higher equipment costs, compliance costs, and procurement challenges associated with meeting federal tax credit eligibility requirements.

The resulting technology cost futures provide a structured framework for evaluating how changes in capital and operating costs may affect future resource economics. By evaluating resource portfolios across low, reference, and high-cost futures, PGE can identify strategies that remain cost-effective and resilient under a range of plausible technology development pathways.

7 Portfolio Analysis

This chapter summarizes results of PGE's portfolio analysis, including a summary of scoring results of all portfolios modeled and a more detailed review of the HB 2021 Preferred Portfolio and Continued Progress Portfolio. Subsections present details of analysis implications on PGE's small-scale renewable position, community benefits, yearly costs, VPP deployment, and portfolio reliability.

Chapter Highlights

- Clean energy remains central to near- and long-term strategies. Continued deployment of current generation technologies delivered to PGE using near-term transmission service plans can meet reliability needs over the upcoming five years.
- Achievement of 80% emissions reductions come at a significant cost. Near-term clean energy deployment enables emissions reductions, but costs and challenges of incremental reductions increase beyond 60% by 2030. This indicates concerning customer affordability impacts from the remaining 20% of reductions.
- Customer-sited resources continue to make an impact, but costs remain a critical input. Cost-effective energy efficiency and growth of the Virtual Power Plant is foundational. CBREs may provide customer and community benefits but are not widely selected in portfolios that seek to optimize a least-cost, least-risk system.
- Selection of utility-scale hybrid resources has increased. Renewable-storage hybrid projects utilizing existing BPA transmission service plans, and capable of capturing tax credits, offer high value.
- Large load growth is forecasted to spread benefits across customer classes. Additional clean energy needs to serve large load growth will provide system benefits while costs are allocated to large customers through the ratemaking process.
- Thermal resources provide an important reliability backstop. PGE's thermal fleet provides valuable system benefits through the 2030s.
- Transmission is critical in supporting the resources needed across scenarios. Transmission expansion is needed to maintain long-term reliability and support further renewable development and access to markets.
- Emissions targets farther in the planning horizon will require new technology. Emerging non-emitting capacity resources are needed in the second half of the planning horizon to maintain decarbonization progress.

Portfolio analysis in this IRP includes review of new scenarios, inclusion of new scoring metrics, integration of nuanced transmission dynamics, and enhanced assessment of costs, risks, and reliability compared to previous planning exercises. These improvements allow PGE to present new details about the opportunities and tradeoffs associated with alternative options and future conditions.

7.1 Purpose of Portfolio Analysis

Portfolio analysis in PGE's 2026 IRP is designed to explore key planning questions facing the Company and the wider region while highlighting important tradeoffs and uncertainties inherent in this dynamic planning environment. PGE has made significant advancements in portfolio modeling to improve the Company's ability to address important planning topics and be responsive to recommendations from Staff and stakeholders in the 2023 CEP/IRP and subsequent Update.

Key advancements in portfolio analysis have been made to the following areas:

- Hourly emissions analysis,
- Transmission options,
- Modeling of VPP resources alongside traditional supply-side resources,
- Development of alternative portfolios that contemplate continued progress towards emissions reductions while balancing customer affordability, and
- Increased granularity in the exploration of uncertainty and risk using the new modeling tool, ARIA (discussed further in this chapter).

The portfolio analysis performed in this CEP/IRP incorporates PGE's most recent forecasts of energy and capacity needs and updated resource cost information. Through a broad set of scenario and future combinations, PGE's capacity expansion model, ROSE-E, develops alternative resource portfolios capable of meeting system needs under different planning assumptions. These portfolios are used to examine key questions regarding reliability, affordability, decarbonization, transmission availability, large-load growth, resource adequacy methodologies, and federal tax policy uncertainty. Section 7.2 describes how a wide range of scenarios are designed to evaluate key questions of interest across a range of planning structures and environments. These scenarios are described in detail in Section 7.3.

Subsequent sections present the results of these analyses and highlight the insights they provide for long-term resource planning. The wide range of scenarios and resource buildouts are analyzed from multiple angles to consider portfolio cost and risk, annual cost impacts, resource adequacy, hourly emissions, and policy compliance. This includes analysis in PGE's new risk assessment tool, ARIA, which expands on traditional portfolio evaluation by assessing cost and risk of portfolio buildouts across a very wide range of future economic conditions.

Cost and risk insights from ARIA are combined with metrics for GHG emissions, community benefits, and other non-traditional scoring metrics in the portfolio scoring process to evaluate portfolio performance. The combined insights from these analyses inform a robust portfolio scoring process used to identify a HB 2021 Preferred Portfolio that meets all regulatory requirements in the least-cost, least-risk manner and complies with HB 2021 emissions reduction targets, as required by rules. In addition to informing the selection of a new HB 2021 Preferred Portfolio, portfolio scoring identifies the Continued Progress portfolio, which models a balanced approach to creating a reliable and affordable portfolio while continuing to make progress toward emissions reduction targets. Together, the HB 2021 Preferred Portfolio and Continued Progress portfolio are used to inform the Action Plan, as described in Chapter 2.

7.2 Portfolio Analysis Design Framework

Portfolio analysis is an essential diagnostic tool to evaluate alternative scenarios and allow for consideration of resource-planning tradeoffs. Portfolio analysis is predicated on an assumed expected planning environment. Upon establishing an expected baseline, portfolio analysis varies key decision variables and sources of uncertainty to highlight risks and trade-offs. Discussion of portfolio analysis results focuses on the impact of those key variables and uncertainties on outcomes (information on the important underlying assumptions about resource availability that create a realistic view of the planning environment can be found in Appendix H). Envisioning different scenarios and futures allows for the development of a flexible resource plan, allowing PGE to adapt as it moves from the planning environment of the past toward that of the future.

PGE designed 24 distinct scenarios to test the effect of key policy and planning considerations. PGE presented and solicited stakeholder feedback on a draft list of planned scenarios at the May 2026 CEP/IRP Roundtable.[109] Each scenario represents one potential planning environment defined by 5 structures (regulatory, load, resources, transmission, and tax credits). Each scenario is analyzed across a range of futures which capture uncertainties in capacity and energy needs, power and gas prices, and resource technology costs.[110] For each future, PGE's capacity expansion model, ROSE-E, elects the combination of resources that minimizes system costs across the planning horizon. For more information on ROSE-E and its constraints see Appendix Section H.6.

Three hundred and thirty-three resource buildouts are produced for each scenario, exploring outcomes across all combinations of price, need, and technology futures, which are described in Section 6.6.[111] Comparing Reference Case resource buildouts across scenarios provides insight into how various future environments influence the timing and quantity of resource acquisition. Figure 49 provides a diagram of the portfolio design framework, and Table 22 defines key terms used in portfolio analysis.

[109] The May 2026 Roundtable is available here.
[110] See Section 6.6 Portfolio Construction Futures for more detail.
[111] 37 price futures, 3 need futures, and 3 technology cost futures.

Figure 49. Portfolio Analysis Design Framework

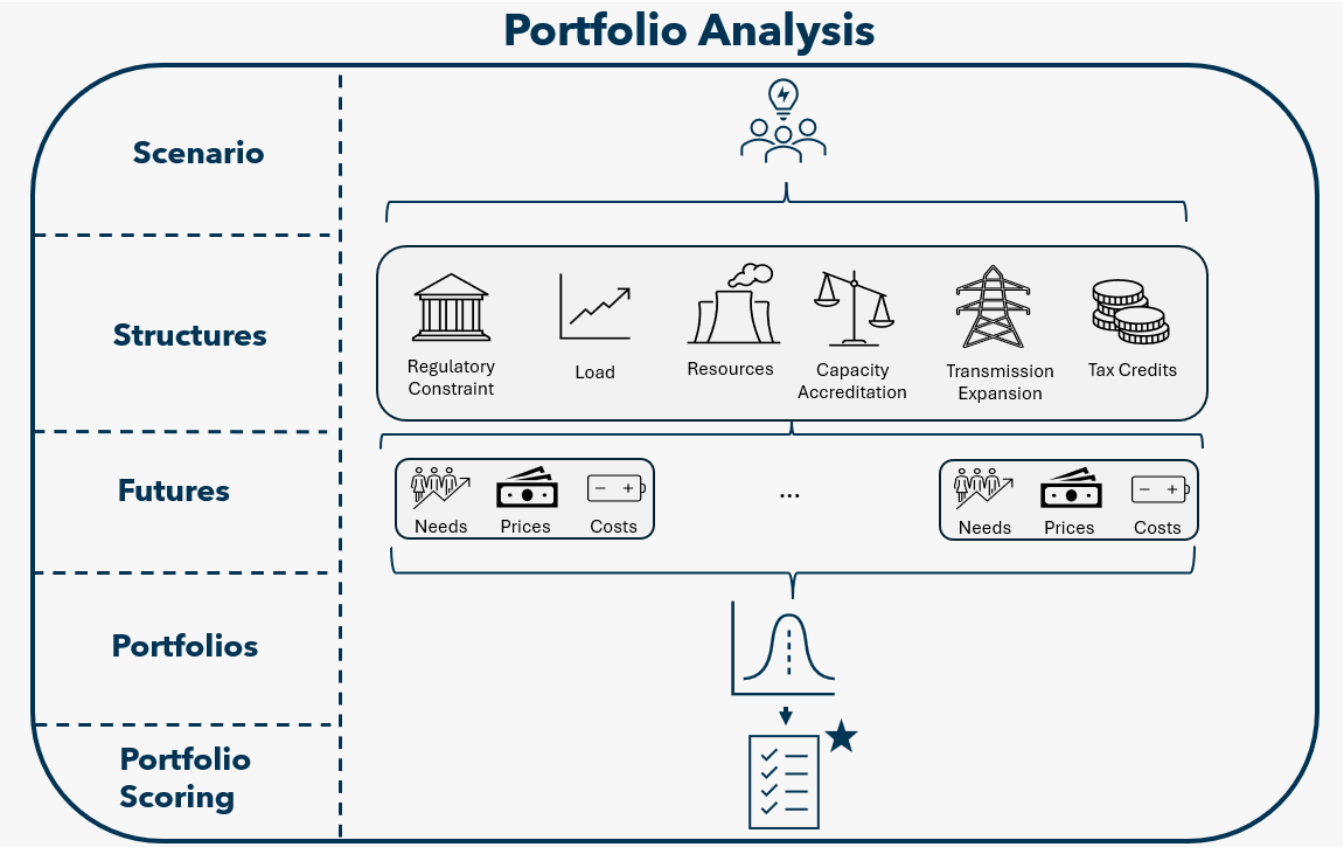


Table 22. Portfolio Analysis Design Framework–Key Terms

Term	Description
Portfolio Analysis	The analytical framework used to identify the HB 2021 Preferred Portfolio.
Scenario	A planning paradigm defined by a fixed planning Environment, producing 333 associated Resource Buildouts.
Structure	Variables which represent discrete changes in planning assumptions. Structures varied are: Regulatory Constraint, Load, Resources, Capacity Accreditation Method, Transmission Expansion, and Tax Credits.
Future	A simulation capturing deviations in system needs, price futures, and technology costs. Numerous Futures are used to capture uncertainties which influence the spread of Resource Buildouts for each Scenario.
Portfolio	Least-cost buildout of incremental resource additions; one for every Future analyzed for each Scenario.
Portfolio Scoring	Compare portfolios using traditional and non-traditional scoring metrics to identify least-cost, least-risk resource buildouts and inform the Action Plan.

7.3 Scenarios Analyzed

As described above in Section 7.2, altering key structures of a scenario allows PGE to estimate the effect of key constraints in the planning environment. Quantifying the effects of uncertainties aims to drive a no-regrets resource plan that balances PGE customers' need for an affordable, reliable, and decarbonized power supply. Table 23 displays the key structural assumptions that define the 24 scenarios analyzed in the 2026 IRP.

The scenarios were designed to create bookends on resource needs, ranging from the highest amounts needed to maintain reliability, meet HB 2021 emissions reductions targets, and serve all forecasted sources of load growth, to the lowest amounts needed to maintain reliability while serving core load growth only. Additional details about the assumptions that define each of the scenarios, including GHG Glidepath, Reliability Only (RO), Continued Progress, and Core Load Growth Only (CGO) can be found in Appendix I Scenario Descriptions. Across this range of pathways, alternative assumptions about contract extensions, transmission availability, and other planning assumptions are varied to provide additional points of comparison.

Table 23. Portfolio Analysis Scenarios

Scenario Number and Name	Regulatory Structure	Load Structure	Resource Structure			Transmission Expansion Structure	Tax Credit Structure
			Base Portfolio	New Gas Contracts	Additional DSG		
1. GHG Glidepath	80% Emissions Glidepath	Base Case	Base Case	No	Yes	Base Case	Base Case
2. RO	Reliability Only	Base Case	Base Case	Yes	Yes	Base Case	Base Case
3. Continued Progress	Continued Progress	Base Case	Base Case	Yes	Yes	Base Case	Base Case
4. GHG Glidepath - CGO	80% Emissions Glidepath	Core Growth Only	Base Case	No	No	Base Case	Base Case
5. RO - CGO	Reliability Only	Core Growth Only	Base Case	Yes	No	Base Case	Base Case
6. Continued Progress - CGO	Continued Progress	Core Growth Only	Base Case	Yes	No	Base Case	Base Case
7. GHG Glidepath - Hydro	80% Emissions Glidepath	Base Case	Base + Hydro	No	Yes	Base Case	Base Case
8. RO - Hydro	Reliability Only	Base Case	Base + Hydro	Yes	Yes	Base Case	Base Case
9. Continued Progress - Hydro	Continued Progress	Base Case	Base + Hydro	Yes	Yes	Base Case	Base Case

Scenario Number and Name	Regulatory Structure	Load Structure	Resource Structure			Transmission Expansion Structure	Tax Credit Structure
			Base Portfolio	New Gas Contracts	Additional DSG		
10. GHG Glidepath – CGO - Hydro	80% Emissions Glidepath	Core Growth Only	Base + Hydro	No	No	Base Case	Base Case
11. RO – CGO - Hydro	Reliability Only	Core Growth Only	Base + Hydro	Yes	No	Base Case	Base Case
12. Continued Progress – CGO - Hydro	Continued Progress	Core Growth Only	Base + Hydro	Yes	No	Base Case	Base Case
13. RO - Colstrip	Reliability Only	Base Case	Base + Colstrip	Yes	Yes	Base Case	Base Case
14. RO – CGO - Colstrip	Reliability Only	Core Growth Only	Base + Colstrip	Yes	No	Base Case	Base Case
15. RO – Colstrip - Hydro	Reliability Only	Base Case	Base + Colstrip + Hydro	Yes	Yes	Base Case	Base Case
16. RO – CGO – Colstrip - Hydro	Reliability Only	Core Growth Only	Base + Colstrip + Hydro	Yes	No	Base Case	Base Case
17. No Tx	Continued Progress	Base Case	Base Case	Yes	Yes	Unavailable	Base Case
18. No WSPP	Continued Progress	Base Case	Base Case	Yes	Yes	No WSPP	Base Case
19. No NPC	Continued Progress	Base Case	Base Case	Yes	Yes	No NPC	Base Case
20. No T-H	Continued Progress	Base Case	Base Case	Yes	Yes	No T-H	Base Case
21. State RA*	80% Emissions Glidepath	Base Case	Base Case	No	Yes	Base Case	Base Case
22. GHG Glidepath - Tax Credits	80% Emissions Glidepath	Base Case	Base Case	No	Yes	Base Case	Extended
23. RO - Tax Credits	Reliability Only	Base Case	Base Case	Yes	Yes	Base Case	Extended
24. Continued Progress – Tax Credits	Continued Progress	Base Case	Base Case	Yes	Yes	Base Case	Extended

* State RA scenario relies on capacity need and ELCCs derived from alternative capacity accreditation methods, described in Appendix Section H.10– Inputs for State Reliability Metrics Portfolio.

Scenarios one through three (3) from Table 23 are characterized by differences in regulatory structure, representing planning paradigms of HB 2021 GHG Emissions Glidepath, Reliability Only, and Continued Progress. These scenarios are overviewed below; see Appendix I Scenario Descriptions for more detail on the policy-related assumptions of each.

The GHG Glidepath portfolio models a resource buildout that is constrained to a linear emissions reduction glidepath that achieves the mandates of HB 2021 across the planning horizon. The GHG Glidepath scenario does not allow for the addition of incremental gas contracts. The Reliability Only portfolio models a resource buildout in a planning environment where resource needs are driven by reliability needs associated with meeting load growth and replacing expiring contracts, with no enforced HB 2021 emissions reductions targets. The Continued Progress scenario is designed to explore alternative pathways of HB 2021 compliance that make continued progress towards emissions reduction targets without being constrained to meet a GHG reduction glidepath. This scenario is modeled to spend approximately 106% of the revenue requirement of the Reliability Only portfolio. The 106% is informed by Section 10 of HB 2021, which defines a 6% increase of the annual revenue requirement for a year as triggering a potential deferral of HB 2021 emissions targets.[112] This methodology does not attempt to implement nor forecast an official Section 10 (cost cap for electric companies) filing but rather inform PGE's modeling analysis of a portfolio that balances execution and affordability risks with decarbonization progress. This scenario does not reflect a complete Section 10 analysis, which is still being defined through regulatory processes.[113] Additional details about the modeling of the Continued Progress scenario can be found in Appendix Section I.3 Scenario Descriptions, subsection on continued progress. In addition to relaxing the emissions constraints, contracts for natural gas generation are available for selection in the Reliability Only and Continued Progress scenarios. All scenarios model compliance with Oregon's Renewable Portfolio Standards.

Scenarios one through three (3) are all modeled using Reference Case load, inclusive of new large load connects. Resources available for selection are described in Appendix Section H.6.7 New Proxy Resource Options. Capacity is accredited with ELCC curves estimated in Sequoia (See Section 6.5), and all extra-regional transmission options are available for selection (See Section 5.3). The structure of the remaining scenarios alter assumptions across the remaining planning structures of load, resources, transmission expansion, and tax credit to test key questions of interest across each of the three (3) regulatory structures.

7.4 Portfolio Analysis Results

In the proceeding sections, key scenarios are organized within groups that allow the impacts of the different structures of the design framework to be explored. Detailed results for key modeling outcomes of resource additions, portfolio costs and risk, and emissions for each scenario modeled in ROSE-E are provided in the Standard Information Request data filing. Unless otherwise noted, the results presented in this section represent the Reference Case.[114]

[112] https://olis.oregonlegislature.gov/liz/2021r1/Downloads/MeasureDocument/HB 2021/Enrolled
[113] OPUC Docket No. AR 685 is still in open rulemaking at the time of PGE's 2026 CEP/IRP filing.
[114] The Reference Case is defined by a combination of reference need, reference technology cost, and RRRR price futures.

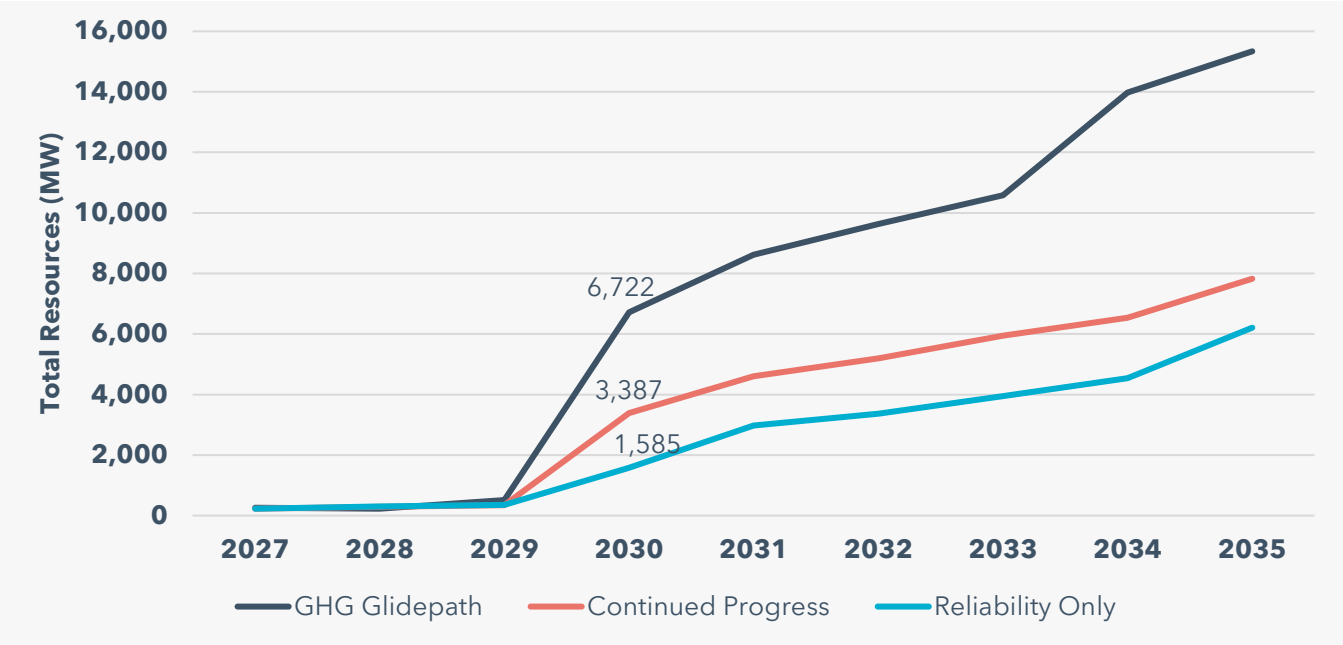
7.4.1 Regulatory Structure Scenarios

Comparison of these three (3) scenarios provides insight into the impact of three (3) important regulatory drivers on resource needs, emissions outcomes, and portfolio costs. This section evaluates the results of these three (3) scenarios under reference assumptions. Insights from analysis of the full range of 333 futures are discussed as part of portfolio scoring in Section 7.5.

7.4.1.1 Resource Additions

The total resource additions in each scenario are shown from 2027-2035 in Figure 50. Comparison of these results show that 1,585 MW of new resource additions are required to meet reliability needs through 2030 in the RO scenario. The quantity of resource additions increases substantially with the additional requirement of meeting emissions reductions targets in the GHG Glidepath scenario, with 6,721 MW needed through 2030. The quantity of resource additions in the Continued Progress scenario falls in between the other scenarios with 3,387 MW through 2030.

Figure 50. Reference Case Total Resource Additions in Regulatory Structure Scenarios

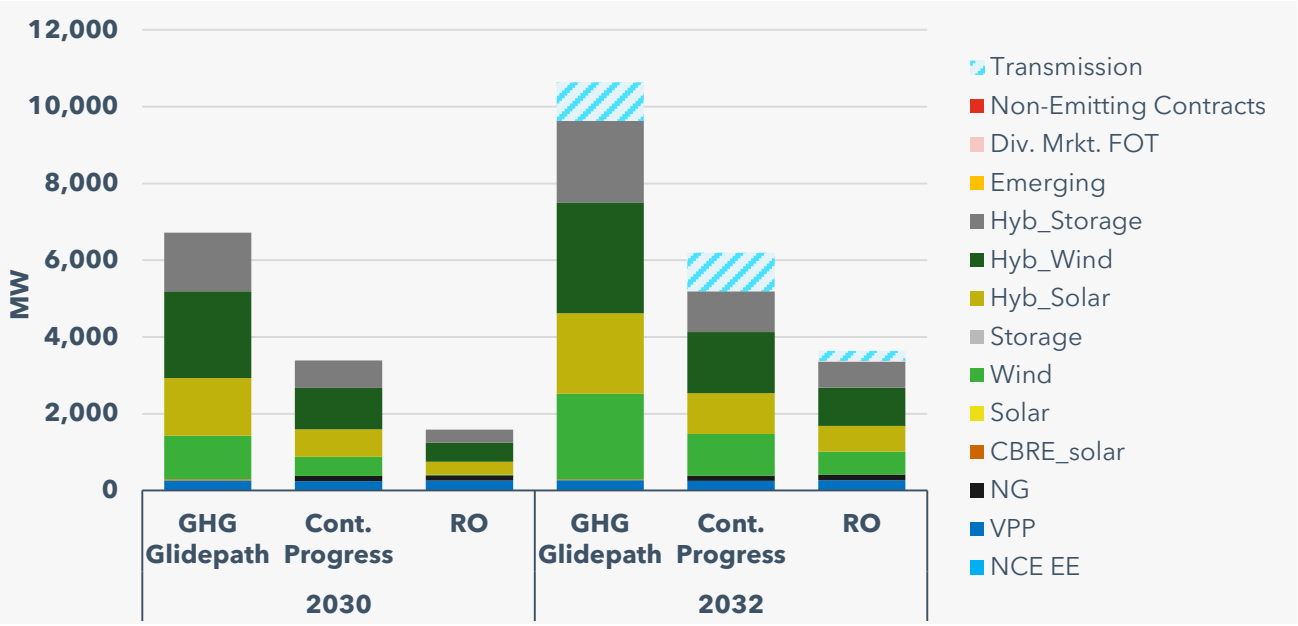


The types of resources that comprise new additions for the three (3) regulatory structure scenarios are shown for 2030 and 2032 in Figure 51. For more detail on each new resource option modeled and associated economic assumptions, see Appendix G Resource Options. All the portfolios rely heavily on triple-hybrid resources that combine wind, solar, and storage behind a single point of interconnection. Selection of these resources maximizes utilization of scarce transmission availability.[115] While substantial quantities of storage are added as part of the hybrid resources, no standalone storage is added in these three (3) portfolios through 2032. The GHG Glidepath portfolio includes additional quantities of wind/solar/storage hybrids, which are added to ensure

[115] Each MW of interconnected triple-hybrid contains 1 MW of wind, 0.67 MW of solar, and 0.67 MW of 4-hour battery.

achievement of emissions targets in hourly-level emissions modeling. The iterative modeling process used to ensure hourly modeled emissions compliance of portfolios created under the GHG Glidepath Scenario assumptions is described in detail in Appendix Section H.2.2.

Figure 51. Reference Resource Additions of Regulatory Structure Scenarios



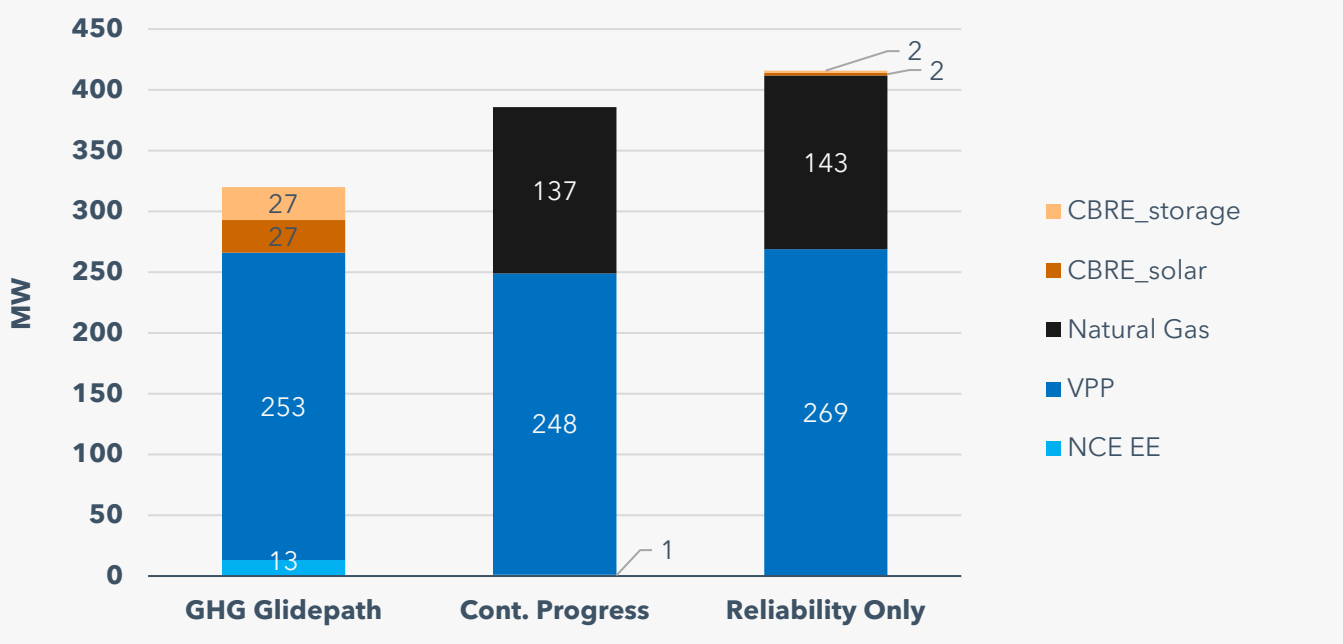
The addition of VPP resources, NCE EE, CBREs, and natural gas contracts are important components of the portfolios in early years of the analysis. Additional details about these select resources are shown in Figure 52. All three (3) portfolios add substantial amounts of VPP resources (including both DSG and flex load resources) through 2032, with 248 MW in the Continued Progress portfolio, 253 MW in the GHG Glidepath portfolio, and 269 MW in the Reliability Only portfolio. Additional discussion about the role of VPP resources can be found in Section 7.10. NCE EE additions through 2032 range from 0 MWa in the Reliability Only portfolio to 13 MWa in the GHG Glidepath portfolio.

CBRE additions through 2032 vary across the three (3) scenarios with 0 MW in the Continued Progress portfolio, 2 MW in the Reliability Only portfolio, and 27 MW in the GHG Glidepath portfolio.[116] See Appendix Section G.3 for more on the CBRE proxy resource assumptions for this planning cycle. CBRE selection in portfolio analysis is influenced by assumptions about rCBI values, which are explored in Section 7.9.

Both the Reliability Only and Continued Progress scenarios that allow access to quantities of natural gas contracts include selection of the majority of the 200 MW available natural gas through 2032.[117] Through 2032, the Continued Progress portfolio includes 136 MW of natural gas, and the RO portfolio includes 143 MW of natural gas.

[116] The Continued Progress portfolio eventually adds 26 MW of CBREs within the planning horizon.
[117] Similar to other proxy resources in portfolio analysis, once selected, natural gas contracts remain in the portfolio throughout the remainder of the planning horizon.

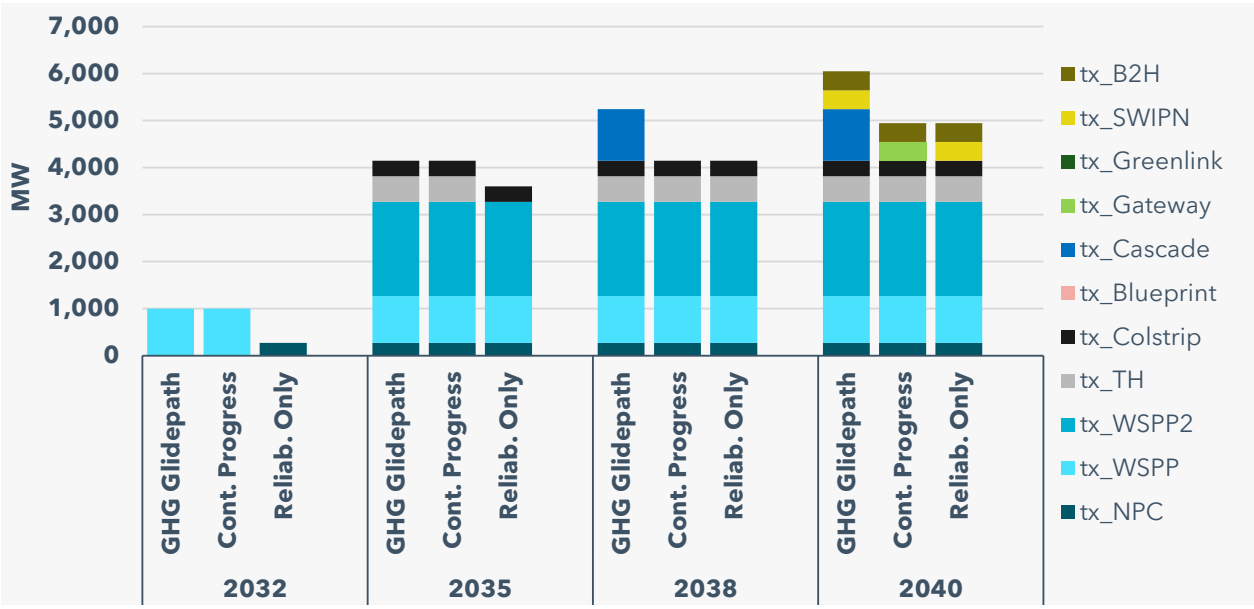
Figure 52. Reference Resource Additions of Select Resource Types Through 2032



7.4.1.2 Transmission Expansion

Transmission expansion and upgrades are essential components of all three (3) scenarios. Details about the transmission options studied in the 2026 IRP can be found in Section 5.3. Total transmission additions range from 4,945 MW in the Reliability Only and Continued Progress portfolios to 6,045 MW in the GHG Glidepath portfolio. All three (3) portfolios include Warm Spring Power Pathway circuits 1 and 2 (WSPP 1 and 2), North Plain Connector (NPC), Harborton-Trojan #3 (TH), Boardman to Hemingway (B2H), and the Garison to Ashe Upgrade (Colstrip).

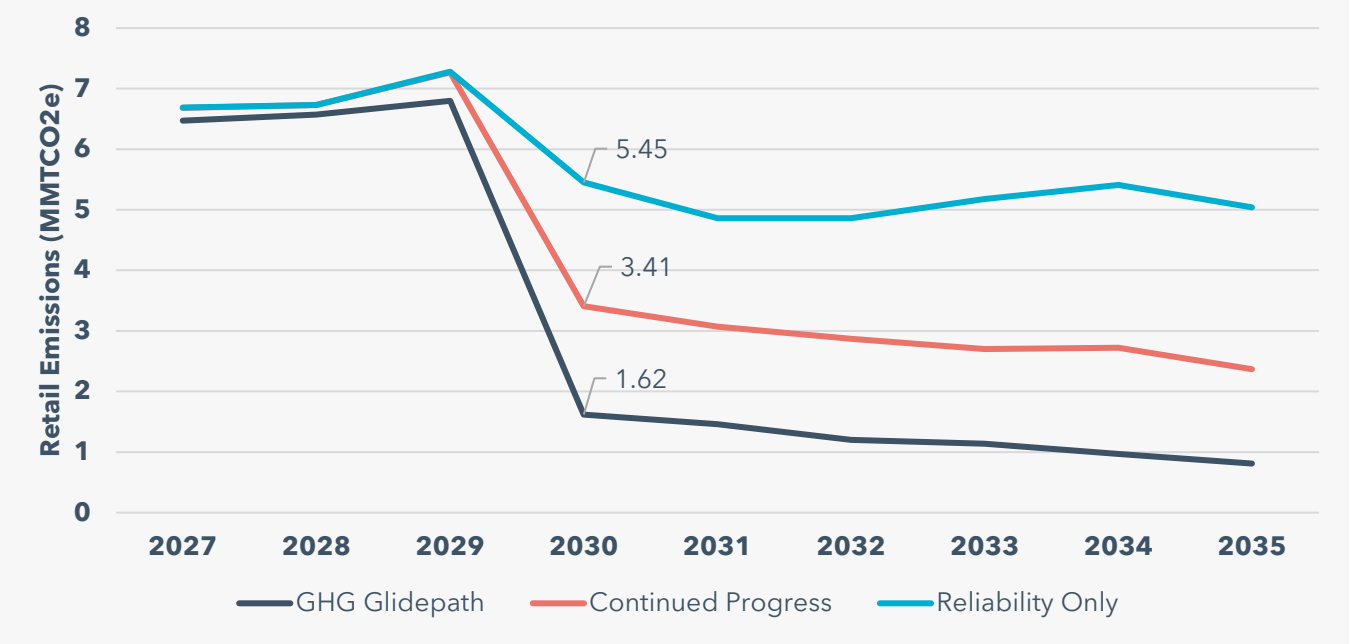
Figure 53. Reference Case Transmission Additions of Regulatory Structure Scenarios



7.4.1.3 GHG Emissions

The GHG emissions associated with retail service for the three (3) portfolios are shown in Figure 54. The GHG Glidepath portfolio produces 1.62 MMTCO2e of retail emissions in 2030, achieving the 80% reduction from baseline requirement of HB 2021. Achievement of this emissions outcome is dependent on the inclusion of an additional 1,463 MW of triple-hybrid resources, beyond those resources in the base ROSE-E resource buildout, to demonstrate hourly modeled emissions compliance. Appendix Section H.2.2 further describes the methodology used to estimate additional resource requirements to meet emission targets under hourly emissions analysis. Retail emissions of the Reliability Only portfolio are 5.45 MMTCO2e in 2030, representing a 33% reduction from baseline. The Continued Progress portfolio selects additional clean energy resources in excess of reliability needs, resulting in further retail GHG emissions reductions with a 58% reduction from baseline in 2030 (3.41 MMTCO2e).

Figure 54. Retail Emissions of Regulatory Structure Scenarios



7.4.1.4 Portfolio Costs

Portfolio costs for the Reference Case buildout of the three (3) regulatory structure scenarios are shown in Figure 55. The GHG Glidepath portfolio, which adds substantially more new resources than the others to achieve HB 2021 emissions targets (at an hourly-modeled granularity), is the most expensive, with 20-year NPVRR of $61.6 billion. The NPVRR of the Reliability Only portfolio, which includes the fewest new resource additions, is the lowest of the three (3) at $37.8 billion. The NPVRR of the Continued Progress portfolio falls between the GHG Glidepath and Reliability Only portfolios at $40.5 billion.

Figure 55. Regulatory Structure Scenarios Reference Case 20-year IRP NPVRR

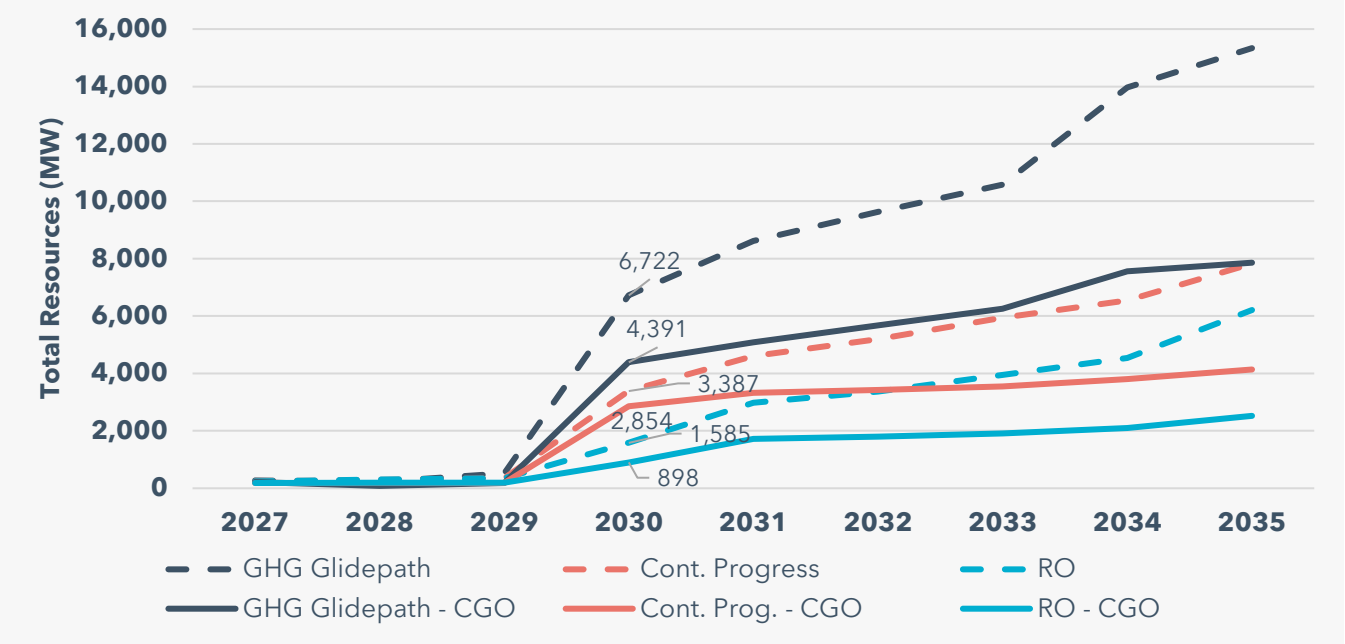
7.4.2 Core Growth Only Scenarios

Each of the regulatory structure scenarios are also analyzed under the Core Growth Only (CGO) structure. Under this structure, the load forecast excludes load growth associated with new Schedule 96 customers. The details of the development of this load forecast variation are provided in Appendix Section H.8. The inclusion of Core Growth Only scenarios in portfolio analysis informs cost-allocation considerations in an environment where projected rapid growth of large load customers, including datacenters, is a driver of resource needs, as discussed in Sections 3.1.1 and 3.1.2.

7.4.2.1 Core Growth Only Resource Additions

Comparison between the portfolios produced under the base case load forecast and the Core Growth Only load forecast is done to estimate the quantity of resource additions that are associated with meeting forecasted new large loads and to provide additional insight into the dynamics of the costs associated with those resource needs. Figure 56 shows the cumulative total resource additions of the three (3) Regulatory Structure scenarios and their Core Growth Only counterparts. As demonstrated, scenarios that serve Core Growth Only require less resources than their base load forecast counterparts, increasingly so under the GHG Glidepath regulatory environment. This analysis supports PGE's ability to thoroughly understand the important dynamics of anticipated large load in the Company's service area and allows PGE to perform cost analysis across customer classes.

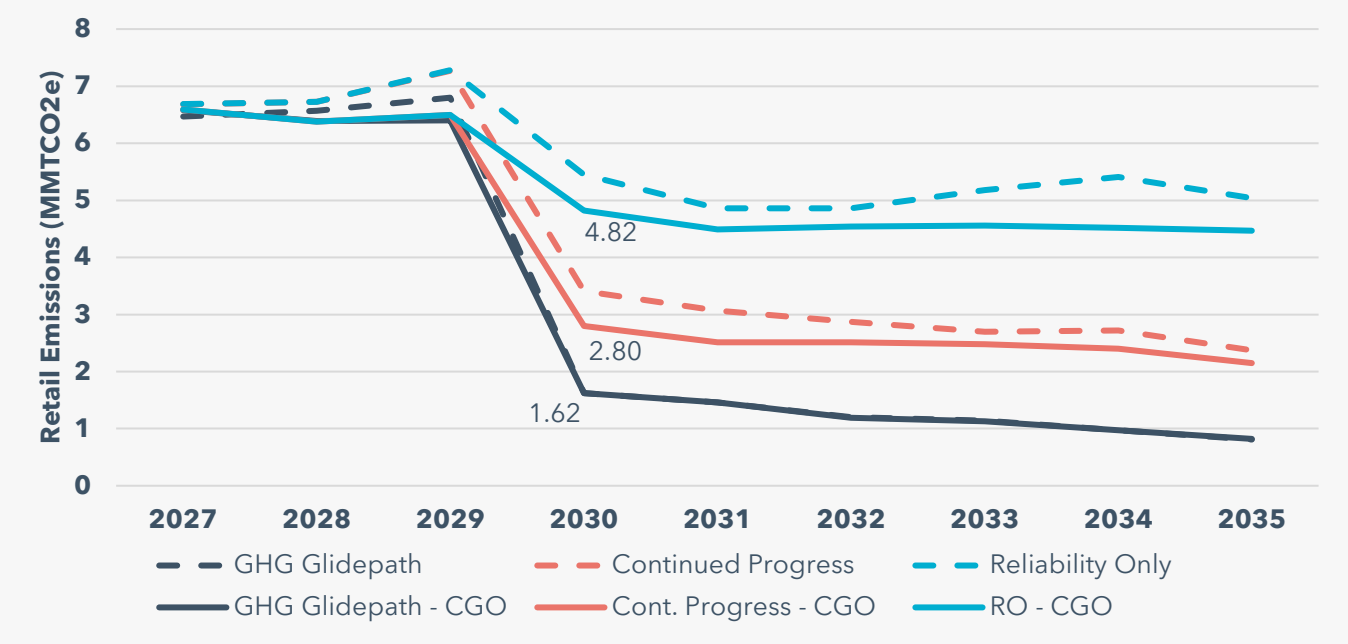
Figure 56. Reference Case Total Resource Additions in CGO Scenarios



7.4.2.2 Core Growth Only Retail Emissions

Retail GHG emissions of the Core Growth Only portfolios and their Base Case load counterparts are shown in Figure 57. Because of the lower load requirements, emissions are lower in the Reliability Only–CGO and Continued Progress–CGO scenarios than the corresponding Base Case load scenarios. Emissions in the GHG Glidepath–CGO scenario are the same as in the Base Case because both portfolios have been augmented with additional non-emitting resources to achieve emissions in alignment with HB 2021 targets, as described in the preceding section.

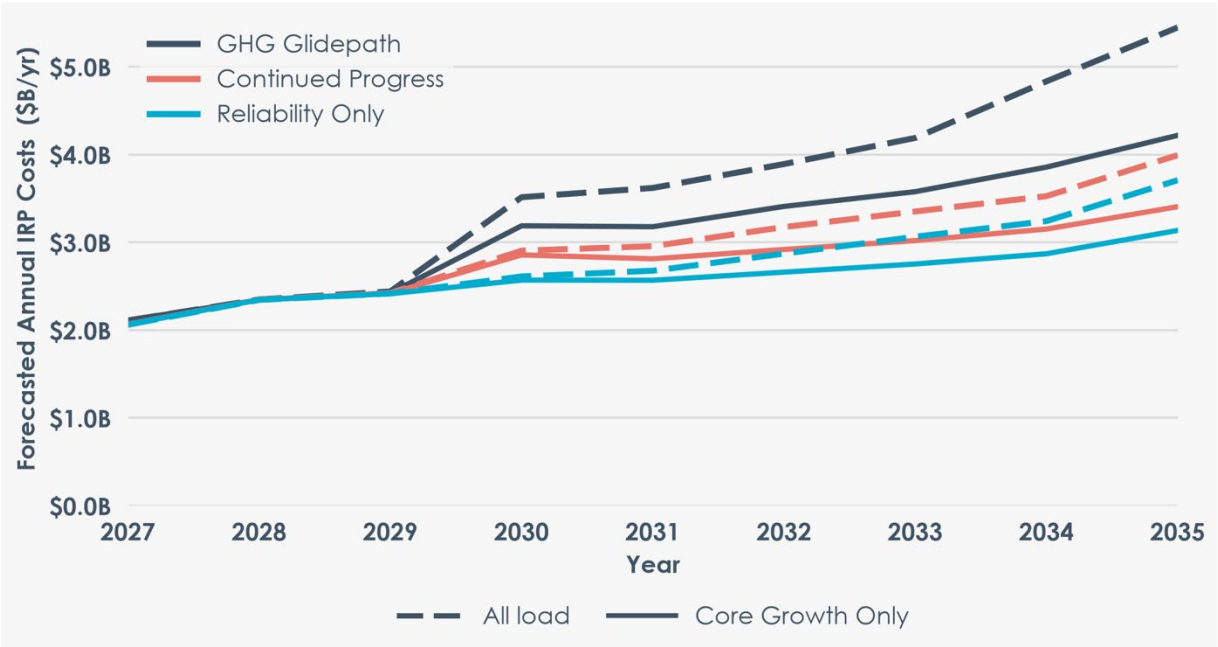
Figure 57. Retail Emissions of CGO Scenarios



7.4.2.3 Core Growth Only Portfolio Costs

Similar to emissions, the total forecasted costs associated with Core Growth Only portfolios are lower than those of their Base Case Load counterparts because of the lower load requirements. When comparing forecasted costs across portfolios, PGE utilizes IRP costs only, which primarily include forecasted costs associated with generation and transmission. These costs are not inclusive of all system costs and other costs included in total revenue requirement that are outside the scope of IRP analysis. The Core Growth Only portfolios serve an important role in supporting PGE's ability to perform further analysis on costs forecasted to be associated with certain customer classes in the 2026 CEP/IRP.

Figure 58. IRP Annual Costs with Base Case Load vs Core Growth Only



7.4.2.4 Forecasted Peak Growth Modifier

To expand on the Core Growth Only results of resource additions, emissions and total portfolio costs, PGE performed further analysis on costs forecasted to be associated with certain customer classes in the 2026 CEP/IRP. The method used in the 2026 CEP/IRP differs from the previous IRP filings by including customer class costs as opposed to total revenue requirement. With this advancement, PGE has also included estimates of how generation and transmission costs may be allocated between customer classes in keeping with recent changes to approved rate-making policy.

To do this, PGE projected total costs by customer class utilizing PGE's current revenue requirement as of April 2026 and adding forecasted IRP costs throughout the planning horizon. Costs that are not directly forecasted within the IRP were forecasted to grow at the rate of inflation. With this forecast of costs, PGE built a growth allocation model that leverages the information derived in the resource additions analysis, which separates the resource additions needed to serve PGE's core load and the associated growth from the additions driven by new large load growth. For each regulatory structure scenario, the cost model pairs the portfolio that includes all load with its CGO counterpart and splits the IRP forecasted costs into two (2) categories:

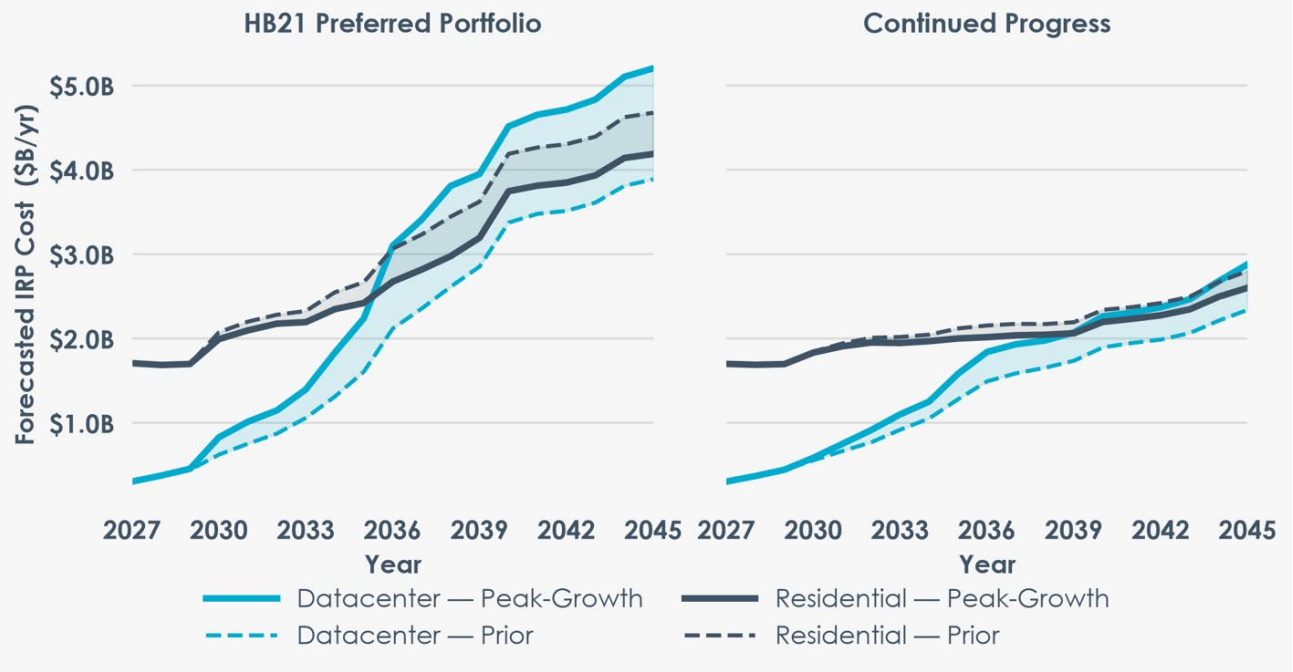
- A core load category – the resource costs that would be incurred to serve core load and the associated growth only, excluding any growth from Schedule 96 customers; and
- A large-load growth category – the incremental cost of the additions anticipated for new large-load demand.

The core load cost category is allocated to customer classes in proportion to each class's ordinary coincident-peak share. The large load growth category is allocated consistent with principles of

PGE's Peak Growth Modifier ("Peak-Growth" or PGM). Since the adoption of the PGM in UM 2377, IRP's prospective cost forecasts incorporate the growth pays for growth cost-causation principle. PGM allocation assigns the growth-driven costs to the customer classes based on the proportional contribution to growth in system demand.

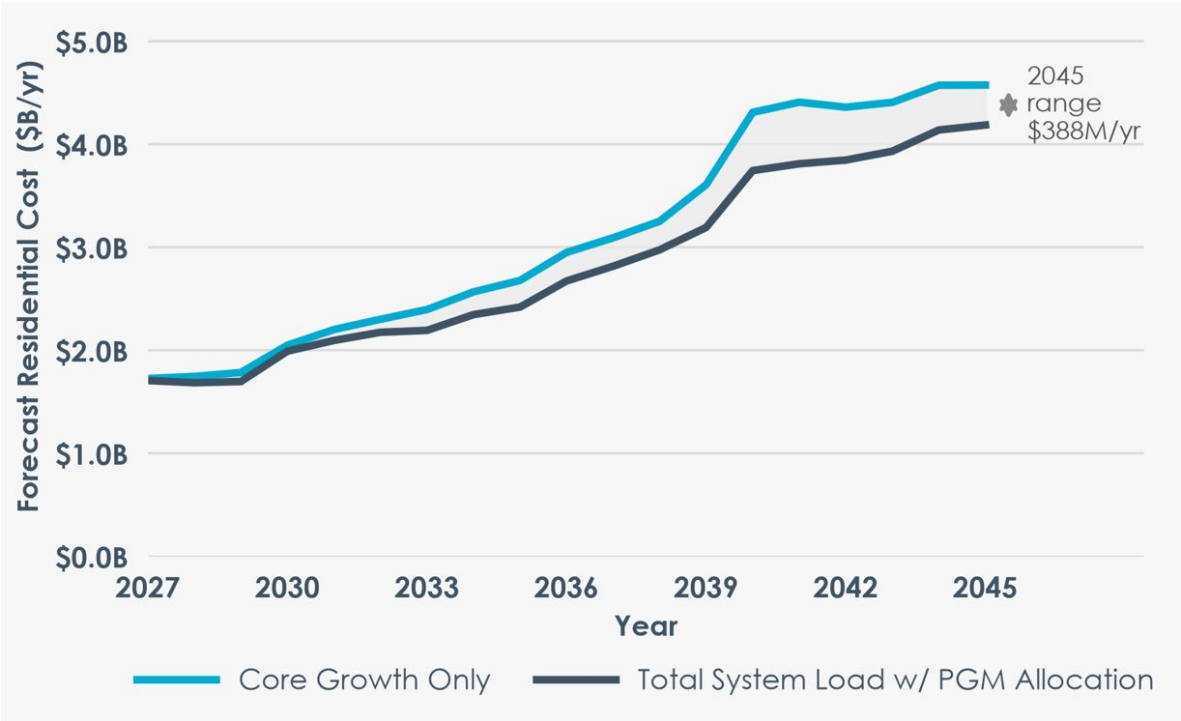
In every scenario and year from 2031 onward, the forecasted PGM lowers the residential rate compared to prior methodology which did not utilize the PGM; the effect is largest in the GHG Glidepath scenario, which carries the largest growth-driven buildout.

Figure 59. Impact of Peak Growth Modifier on the HB 2021 Preferred Portfolio and Continued Progress Scenarios on Costs allocated to Residential and Datacenter Customer Classes



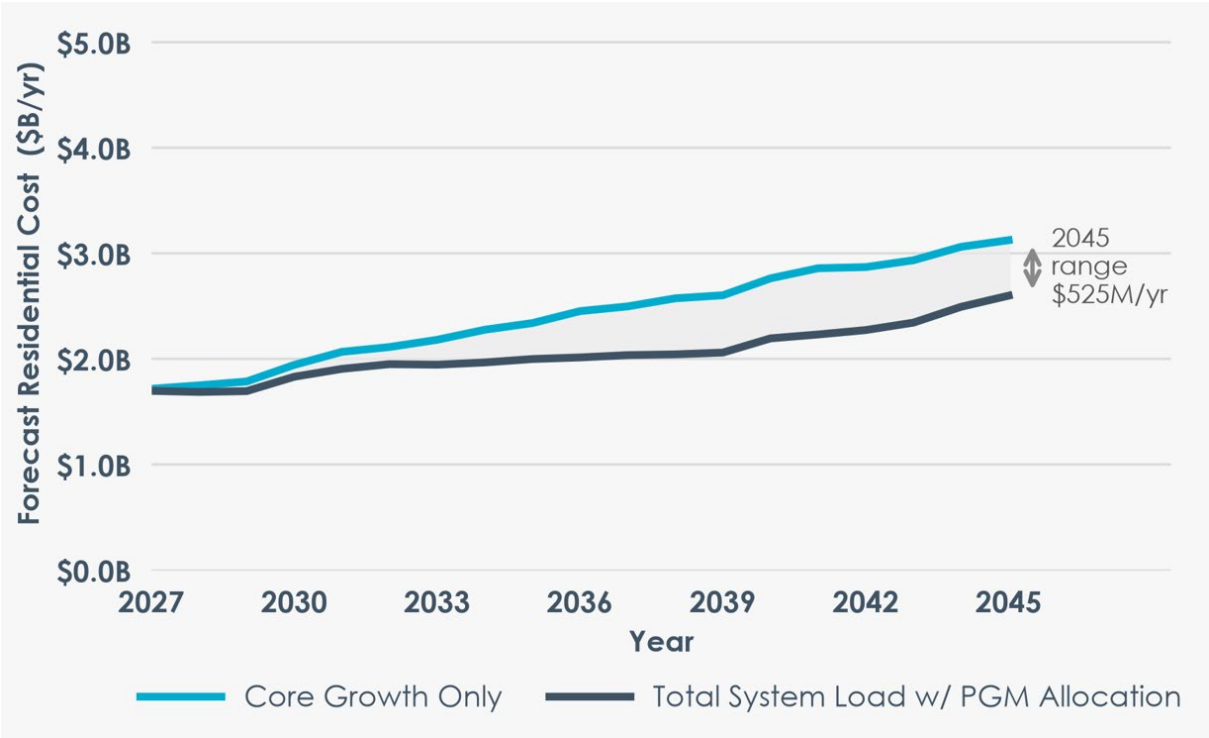
Additional analysis has demonstrated an important prospective finding: the costs allocated to residential customers are lower under the scenario where full load is served and costs are allocated utilizing the PGM mechanism, compared to the scenario where only core load growth is served and no large load growth is present. Figure 60 shows the forecasted IRP costs for residential customers in the GHG Glidepath scenario under these two (2) different paradigms: (1) total system load is served as forecasted, with the PGM in and (2) core growth only load is served, with no PGM instituted given large load is removed from this forecast). This shows that even though the resource additions are higher in the total system load scenario, costs are allocated across customer classes via the PGM policy such that costs allocated to residential customers are forecasted to be lower than costs allocated under a scenario where resource additions are lower, only serving core load growth.

Figure 60. GHG Glidepath Scenarios



This effect is even more pronounced in the Continued Progress scenario shown in Figure 61. This is a result of the resource additions being less in the Continued Progress environment; and thus, the sharing of the existing system costs the predominant category that is distributed according to the PGM tool.

Figure 61. Continued Progress Scenarios



These findings support the conclusion that, when future customer growth contributes appropriately to the infrastructure needed to serve that growth, affordability is supported for all customers over the long term. PGE will continue exploring opportunities to improve affordability by spreading the fixed costs of the system across a larger customer base while supporting investments in reliability and resiliency, driving continued progress towards emissions reduction targets. PGE is committed to working constructively to fairly allocate costs while serving large load customers with the increasingly clean energy demanded by Oregonians.

The forecast PGM, which models the mechanism established in UM 2377, highlights the system benefits that exist when customers who are driving growth are assigned a fair portion of the costs associated with that growth. In turn, all customers can be served by a system that is larger, with the potential for increased flexibility and upgrades that benefit all. This underscores the importance of the ongoing work being done in Oregon to ensure fair and equitable allocation of costs across customer classes.

7.4.3 Resource Structure Scenarios

Ten of the scenarios in portfolio analysis vary assumptions about PGE's base portfolio of existing resources. These resource structure scenarios explore the impact on resource needs of extending existing contracts or signing new contracts. Resource structure scenarios consider 1) hydro contract extension of 100 MW from 2027-2029 and 200 MW from 2030 – 2036 with all energy deliveries settled at market index, and 2) extension of PGE's share of Colstrip for a five-year period through

the end of 2034.[118] Hydro contracts are modeled across all three (3) regulatory structures (Reliability Only, GHG Glidepath, and Continued Progress), while the Colstrip extension is modeled only under the Reliability Only regulatory structure. Results of the resource structure scenarios highlight the impact that extension of emitting and non-emitting contracts can have on incremental resource needs, emissions, and costs.

7.4.3.1 Hydro Contract Extension Results

Impacts of the hydro contract extension on total resource additions are shown in Figure 62 for all three regulatory structures. The hydro contract reduces resource additions in all three (3) scenarios, while the largest impact of extending non-emitting contracts is especially notable in the GHG Glidepath portfolio given high resource needs associated with decarbonization.[119] The hydro contract extension also reduces portfolio costs, as seen in Figure 64, below. Retail emissions across the three (3) regulatory structures are shown with and without the hydro contract extension in Figure 63. Presence of the hydro contract is associated with slightly lower portfolio emissions in early years, before the bulk of other new non-emitting resources are available for selection in the model. In a planning environment with increasing competition for new non-emitting resources, opportunities to extend existing contracts represent an important potential component of a pathway to achieving decarbonization targets.

[118] PGE is required by ORS 757.518 (Section 1, Senate Bill 1547 (2016)) to eliminate the costs and benefits associated with coal-fired resources from rates by the end of 2029. This is different than exiting ownership or shutting down Colstrip, decisions that are tied to the complex ownership structure and associated obligations. As noted in the request, the law also gave PGE the option of continuing to include the costs and benefits, and thus the electricity, from Colstrip in rates until the end of 2034. This short-term exemption recognized the potential cost or reliability impacts to customers of accelerating depreciation and the additional cost risks associated with market exposure and resource procurement. The 2026 IRP is planning for a near-term action window of 2027 – 2032, and the resource planning team included a limited number of scenarios that extend Colstrip through the end of 2034, in line with the flexibility provided in ORS 757.518, to better evaluate this resource and its effect on reliability, affordability and decarbonization.

[119] Counterintuitively, the total quantity of resources in the RO – Hydro scenario can be seen to be higher in some years than the RO scenario in Figure 62 but this is only because transmission MWs are not included in this measure of resource additions, and the RO – Hydro scenario relies less on transmission with only 545 MW in 2034, compared to the 1270 MW in the RO scenario.

Figure 62. Reference Case Total Resource Additions in Hydro Scenarios

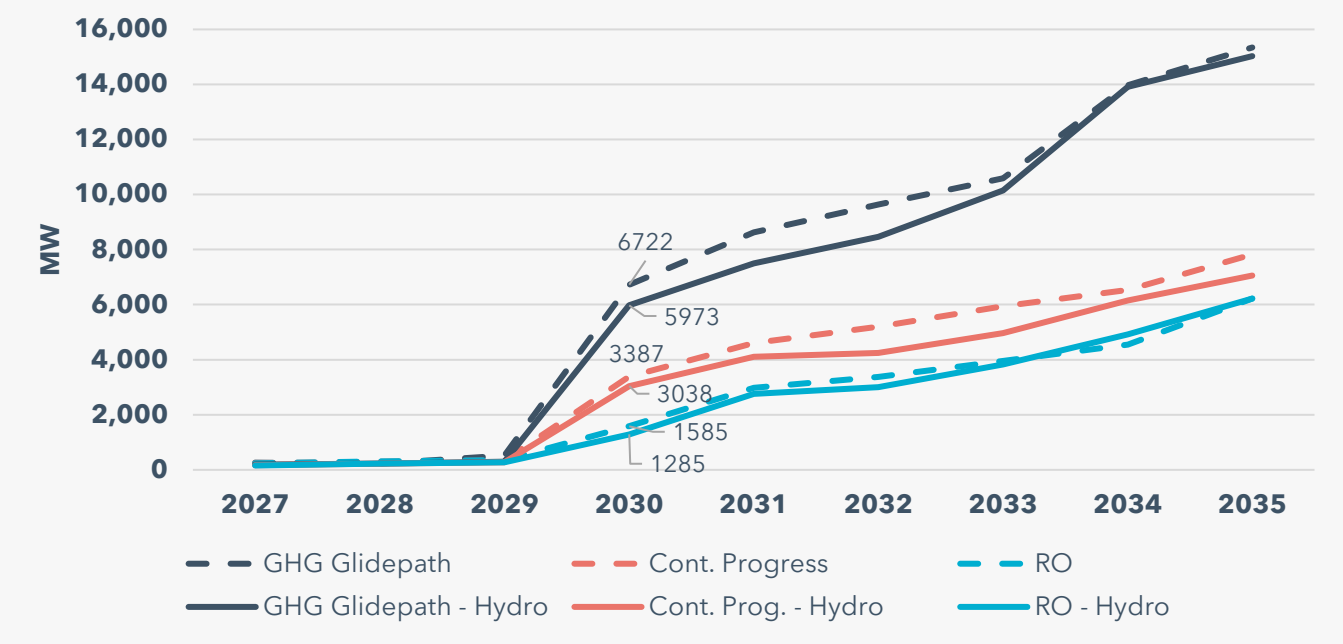


Figure 63. Reference Case Total Retail Emissions in Hydro Scenarios

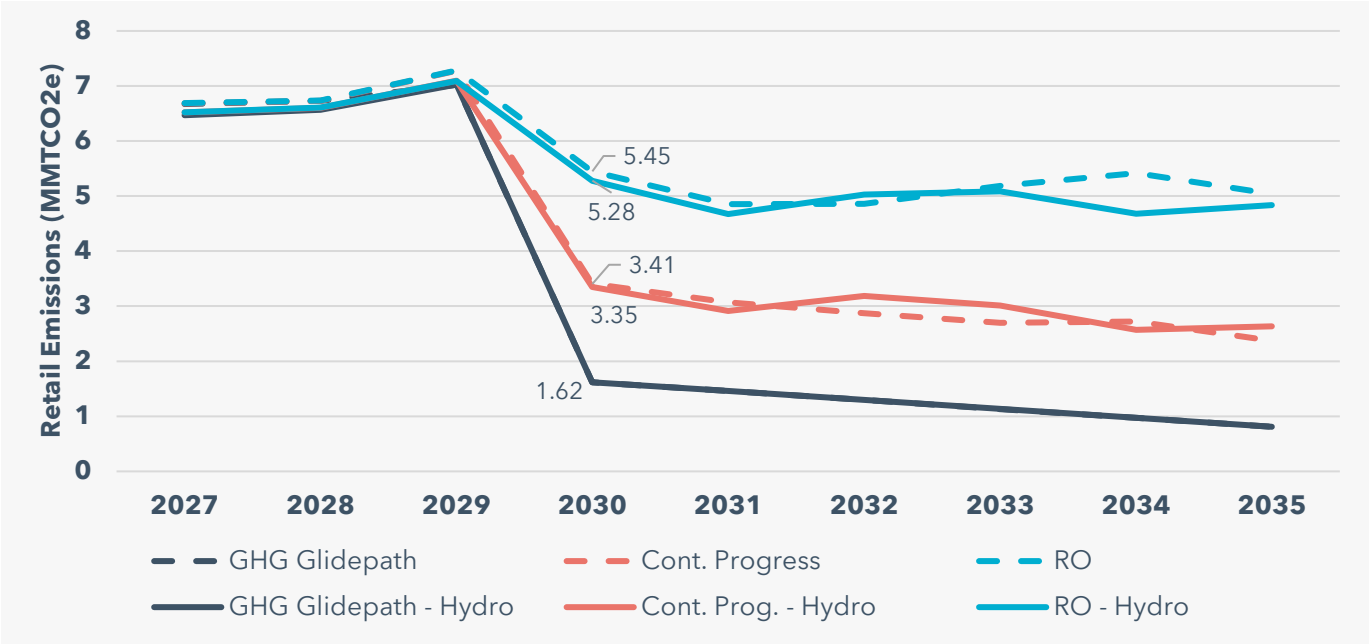
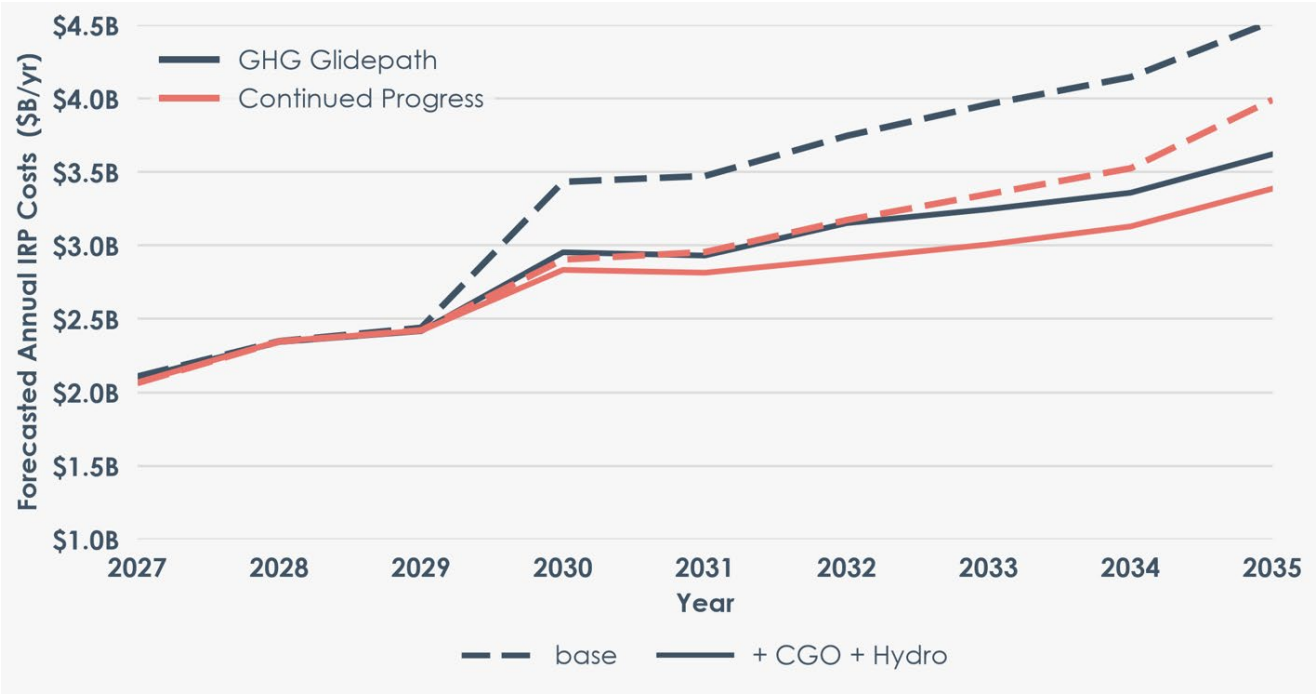


Figure 64. Reference Case Total Portfolio Costs in Hydro Scenarios



The hydro contract was also modeled across the three (3) Regulatory Structures with the Core Growth Only load structure with similar impacts on resource needs, emissions and costs, seen in Figure 65, Figure 66, and Figure 67 below.

Figure 65. Reference Case Total Resource Additions in CGO Hydro Scenarios

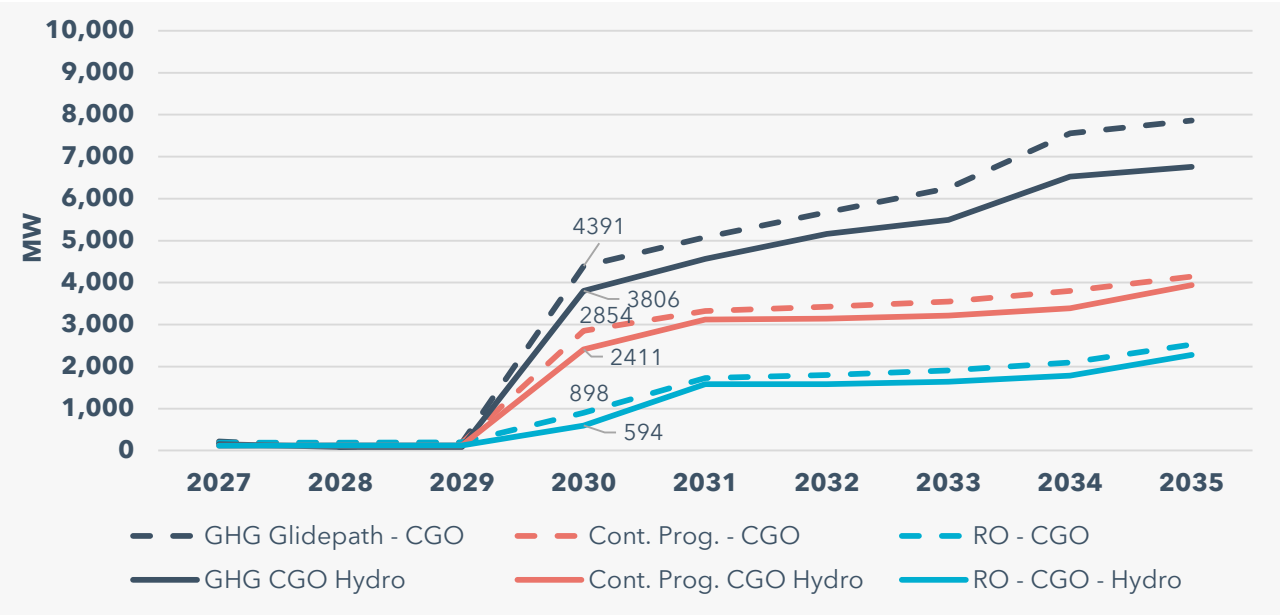


Figure 66. Reference Case Total Retail Emissions in CGO Hydro Scenarios

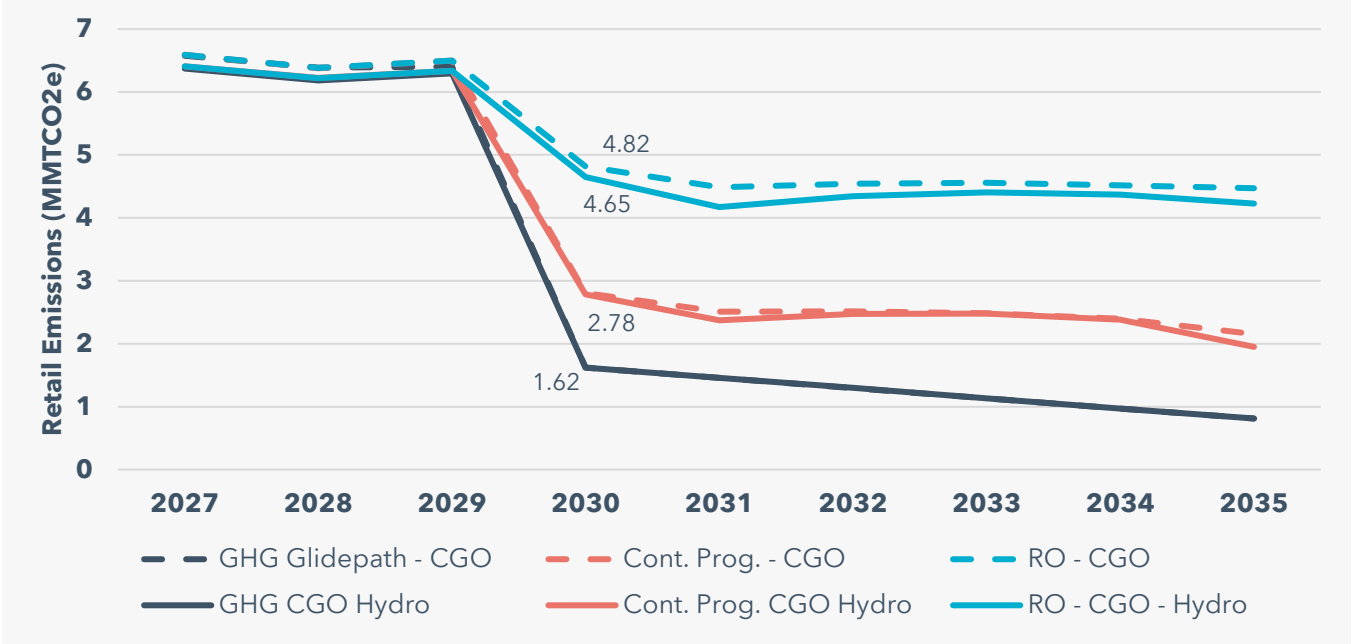
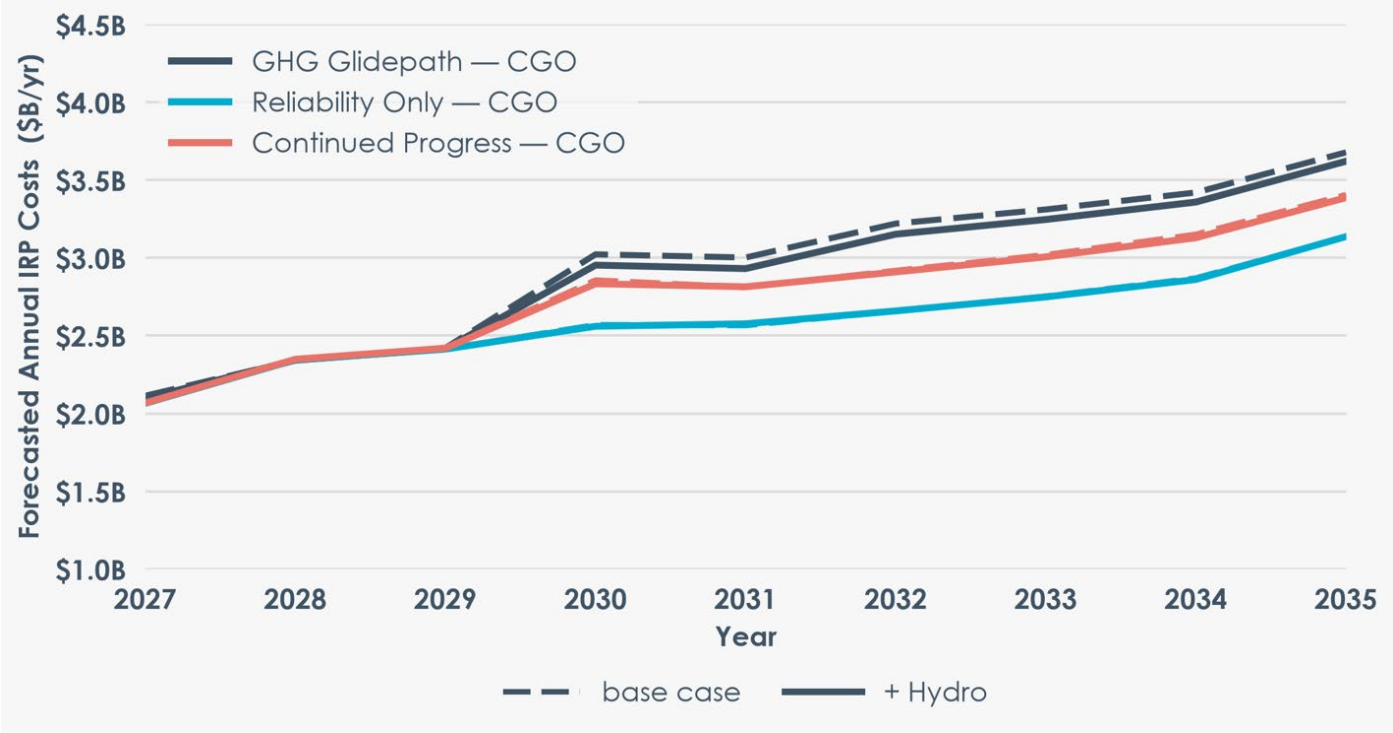


Figure 67. Reference Case Total Portfolio Costs in CGO Hydro Scenarios



7.4.3.2 Colstrip Extension Results

Results of the Colstrip extension scenarios illustrate the potential value of extending sources of thermal capacity in the portfolio when planning to meet reliability-driven capacity needs. The Reliability Only scenario adds nearly 1,000 MW more resources than the RO – Colstrip scenario through 2034 (4,519 MW vs 3,522 MW). The lack of an enforced emissions glidepath under the Reliability Only regulatory structure, makes capacity needs the driver of resource needs under this regulatory structure. While the Colstrip extension scenarios include both the energy and capacity from Colstrip, it is the plant's capacity that provides the majority of benefits to the portfolio in terms of reduced need for incremental resource additions. When the hydro contract is added in addition to the Colstrip extension, resource additions are reduced further, with only 325 MW of new resources needed to meet reliability needs through 2030 in this scenario. The inclusion of the Colstrip extension can be seen to result in higher emissions in 2030-2034 but then reconverge with the emissions of the Base Case Reliability Only scenario in 2035 when Colstrip exits the portfolio (Figure 69).

Figure 68. Reference Case Total Resource Additions in Colstrip Scenarios

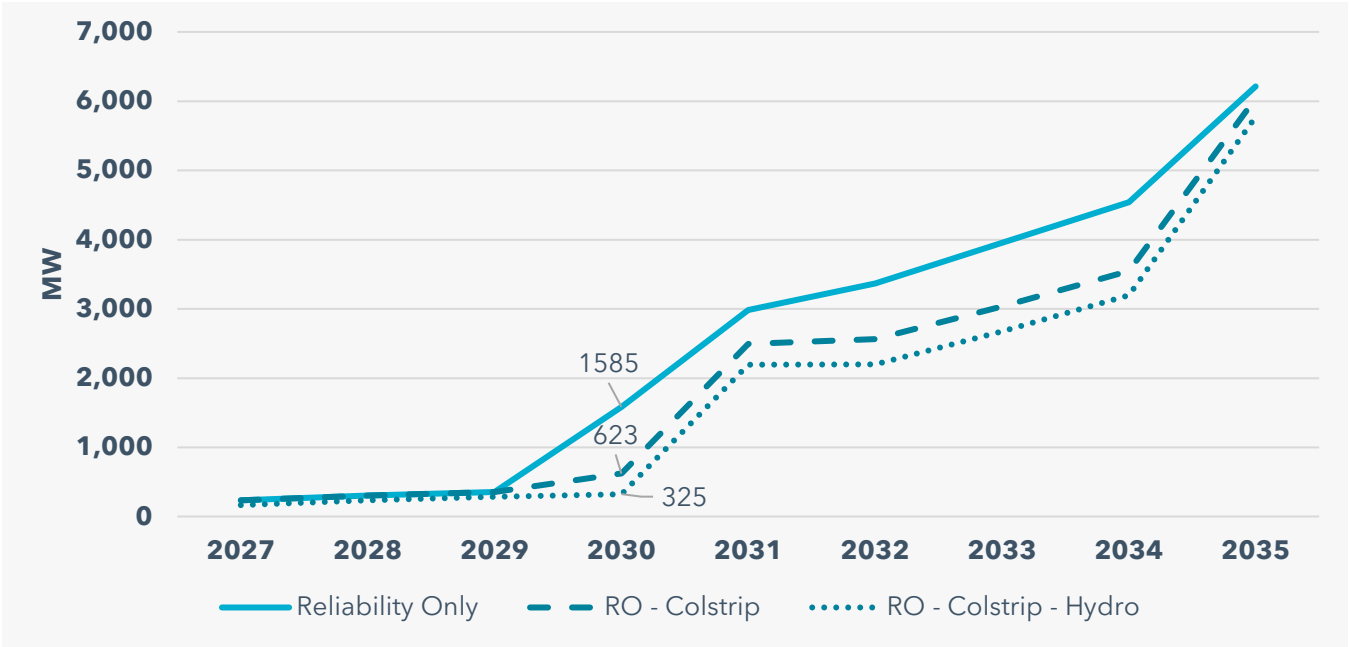


Figure 69. Reference Case Total Retail Emissions in Colstrip Scenarios

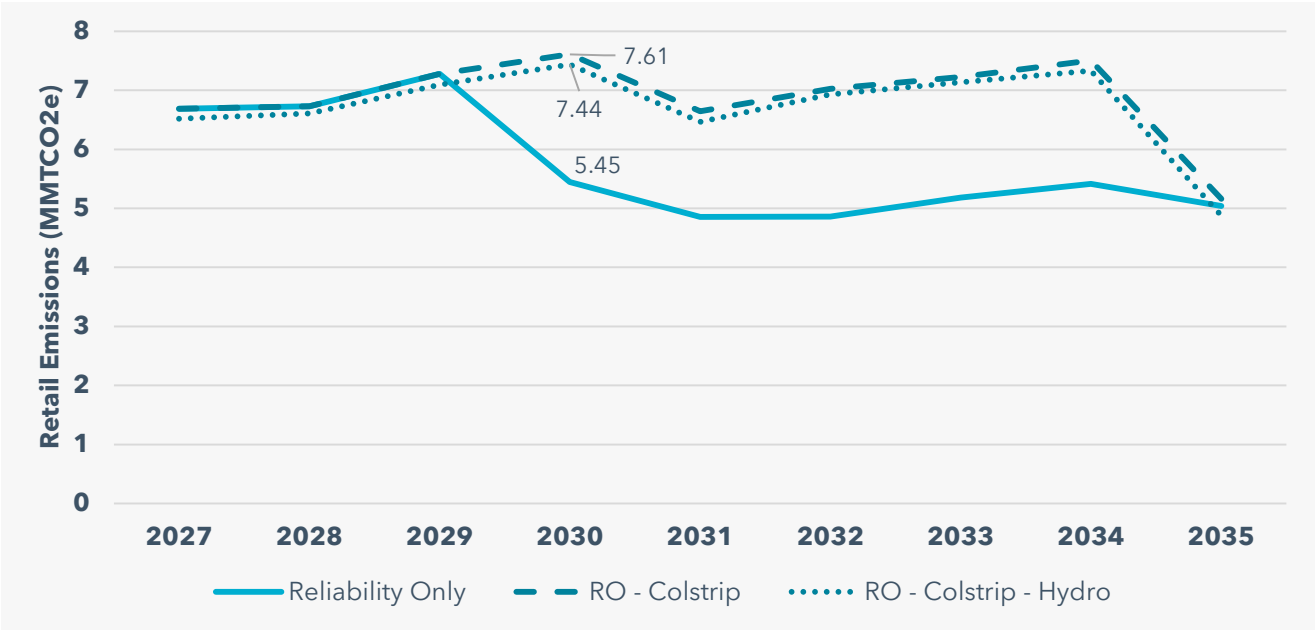
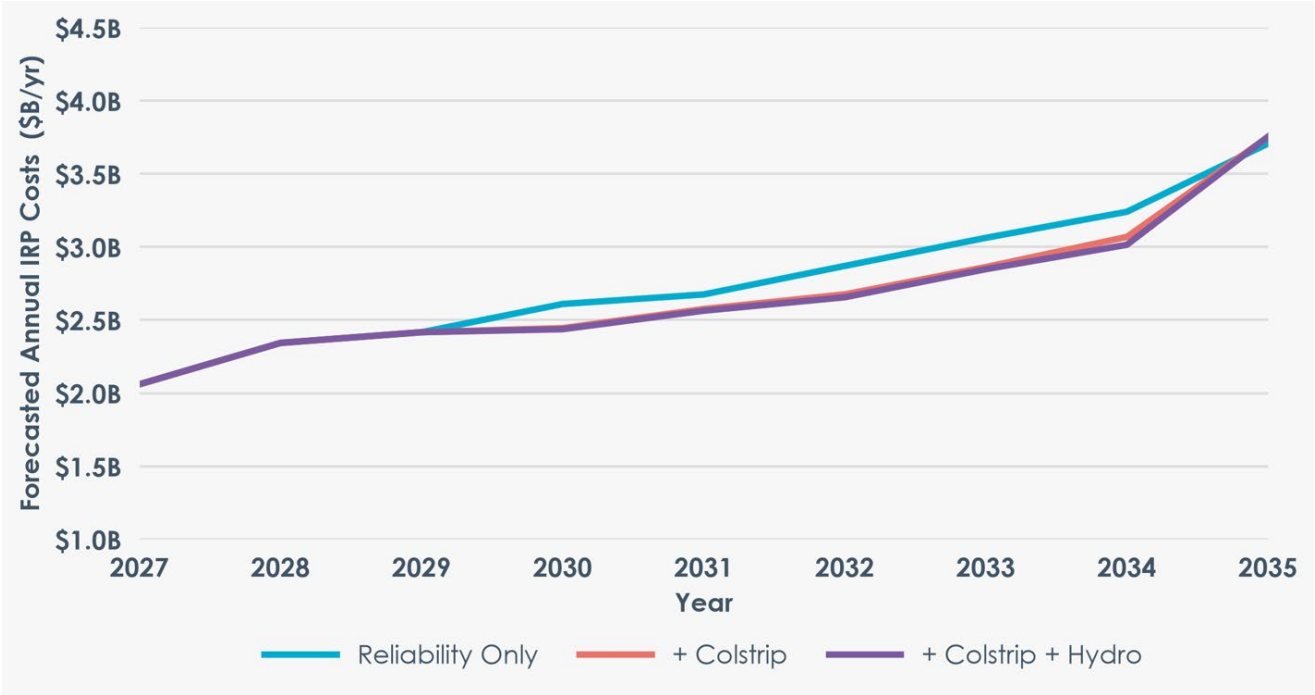


Figure 70. Reference Case Annual Net IRP Costs in Colstrip Scenarios



When the hydro contract and Colstrip extension are modeled under the Core Growth Only load structure, the lowest quantities of resource additions that may be needed to meet reliability requirements are explored. As shown in Figure 71 total 2030 resource additions in the RO – CGO – Colstrip scenario are only 195 MW. Resource additions decrease even further to 125 MW when the hydro contract is layered on in the RO – CGO – Colstrip – Hydro scenario. The inclusion of the

Colstrip extension can be seen to result in higher emissions in 2030-2034 under the CGO structure as well. Similar to the Colstrip extension scenarios analyzed under Base Case load, emissions reconverge with the emissions of the Reliability Only scenario in 2035 when Colstrip exits the portfolio (Figure 72).

Figure 71. Reference Case Total Resource Additions in CGO Colstrip Scenarios

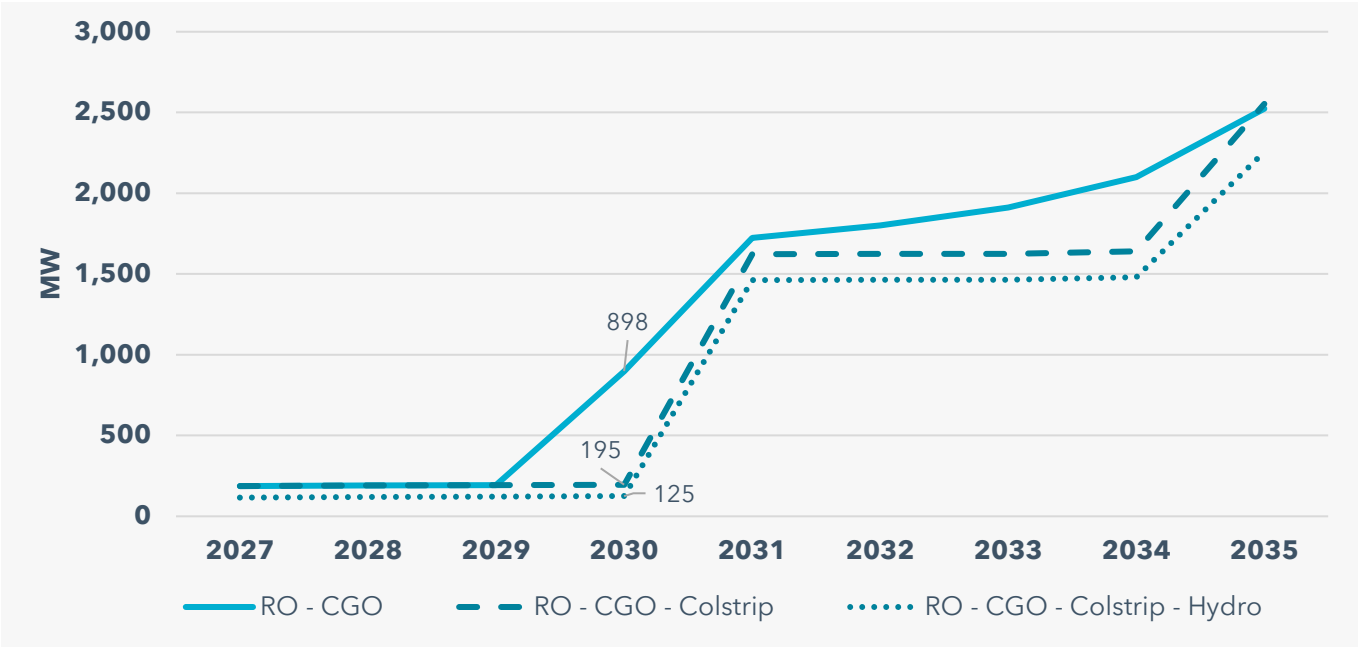


Figure 72. Reference Case Total Retail Emissions in CGO Colstrip Scenarios

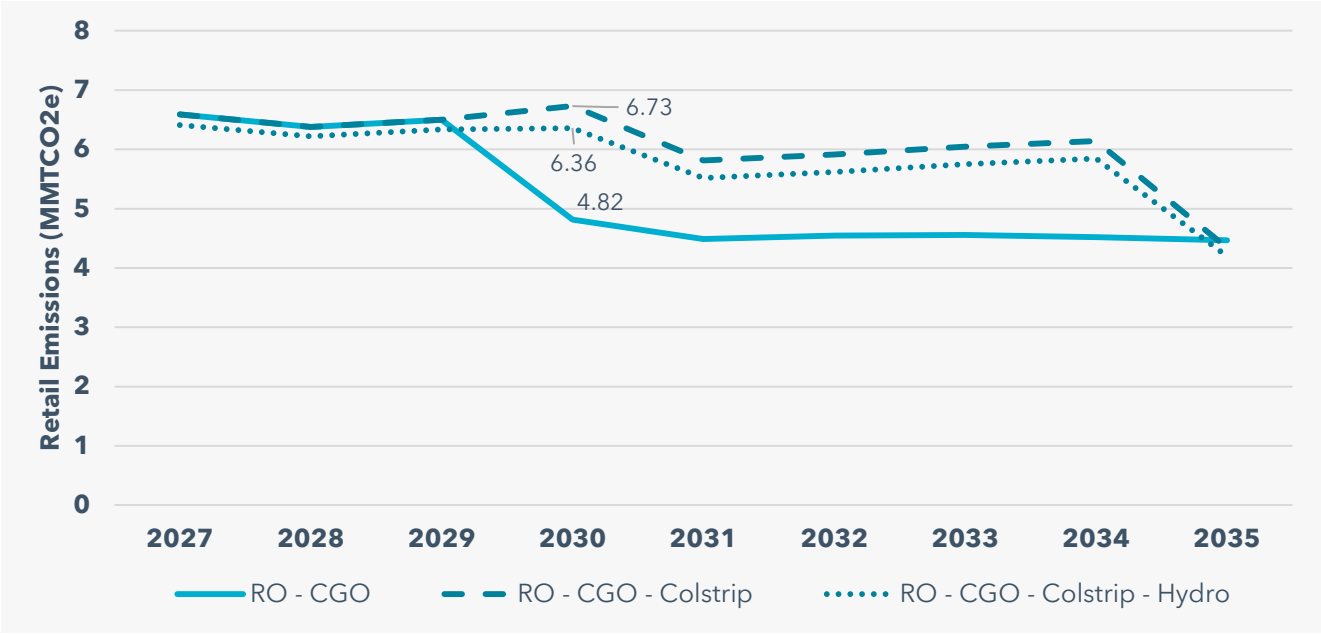
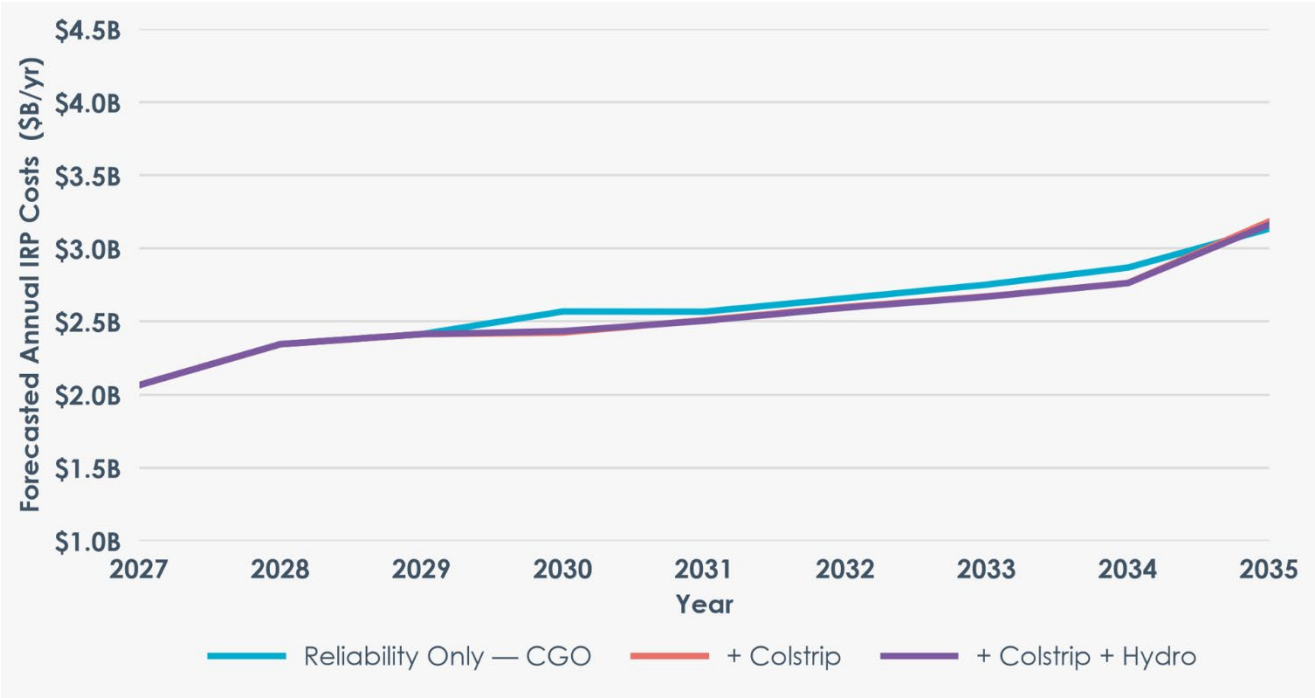


Figure 73. Reference Case Annual Net IRP Costs in CGO Colstrip Scenarios



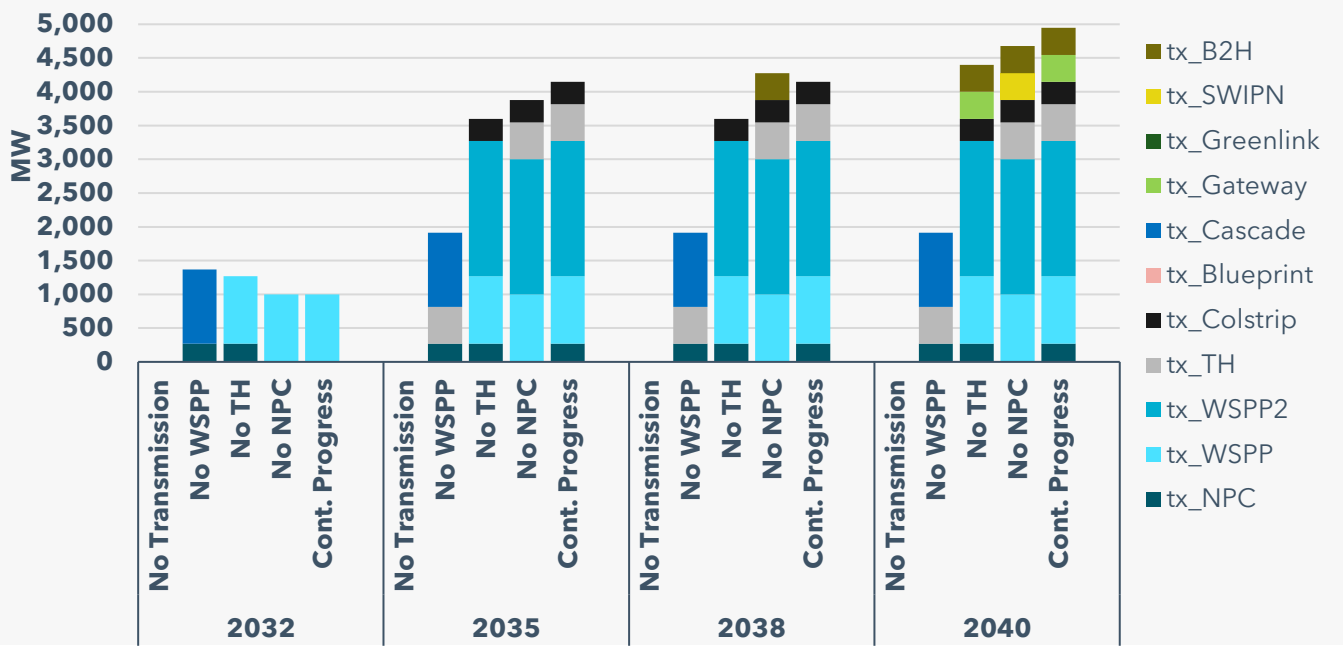
The Colstrip extension is shown to meaningfully reduce the need for resource additions through 2034 across both Base Case load and Core Growth Only, a significant benefit given the ability to minimize reliability risk in the event that clean energy resources are not available to PGE. Results also indicate that a potential Colstrip extension likely reduces customer costs through the extension period (Figure 73).

7.4.4 Transmission Availability Scenarios

Transmission is a critical component of all scenarios modeled under Base Case load structure. scenarios were developed to test the sensitivity of portfolio outcomes to the availability of select transmission options. Transmission availability scenarios vary the availability of one or more of the transmission options that are otherwise heavily relied upon in portfolio construction, while sharing all other structural assumptions with the Continued Progress scenario. Four transmission availability scenarios are analyzed; 1) No Transmission Expansion (No Tx), 2) No Warm Springs Power Pathway (No WSPP), 3) No North Plains Connector (No NPC), and 4) No Harborton-Trojan #3 (No TH).

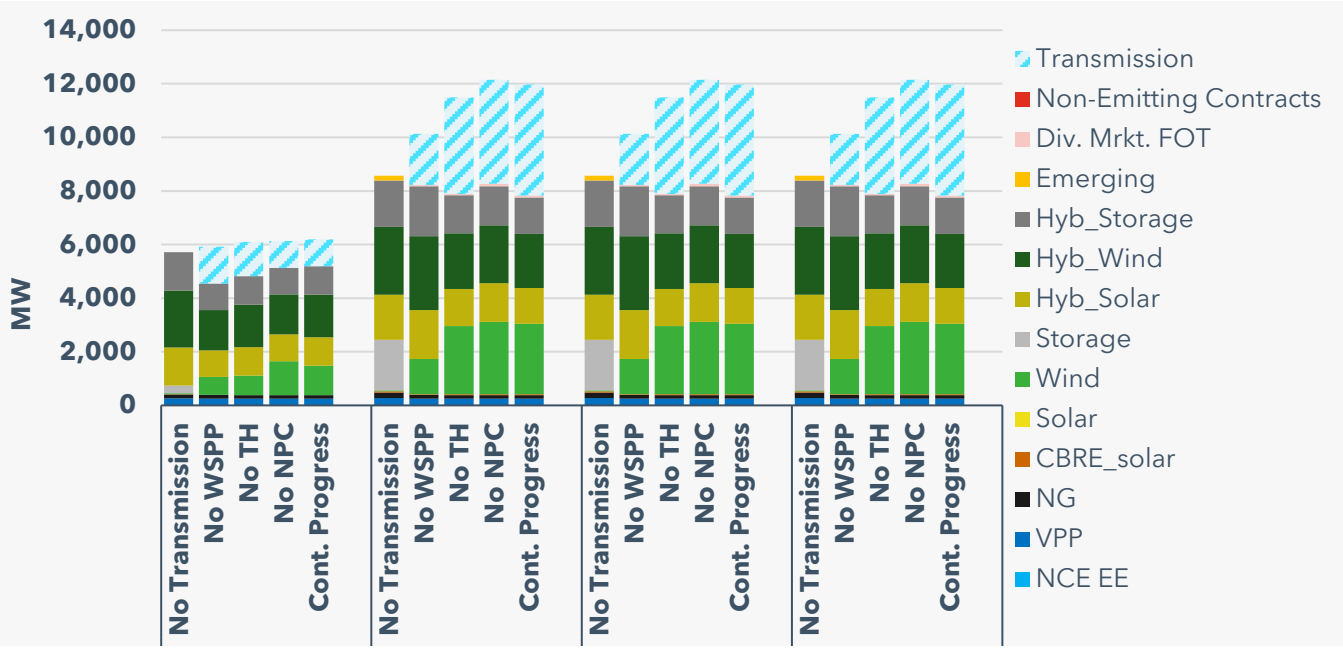
Figure 74 compares the transmission additions of these four scenarios to those of the Continued Progress portfolio. All results shown in this comparison are for the Reference Case. Results show that when transmission options are limited, the model substitutes other transmission options when available and increases reliance on non-transmission-limited resources like standalone storage and emerging technology. Because multiple transmission options are dependent on WSPP (Colstrip, Blueprint, Greenlink, SWIPN, and Gateway) the results of the No WSPP scenario show substantially less transmission than either the Continued Progress scenario or the other transmission availability scenarios.

Figure 74. Reference Transmission Additions in Transmission Availability Scenarios



Comparison of the resources added across these portfolios illustrates the impact of reduced access to transmission (Figure 75). Both the No Tx and No WSPP portfolios have increased reliance on standalone storage and emerging technology to make up for the lack of transmission access. Increased reliance on these resources results in more expensive portfolios, as can be seen in the cost column of Table 26.

Figure 75. Reference Resource Additions in Transmission Availability Scenarios



Restricting transmission forces the portfolio to meet reliability with local resources in place of lower-cost, transmission-delivered wind. The No Tx scenario, which cannot add new transmission, must build substantially more emerging clean-firm capacity and long-duration storage – the most expensive resource types per unit of firm capacity – raising its expected cost (see Figure 76 and Figure 77). These scenarios quantify the portfolio value of transmission and market access as a hedge against local-resource cost.

Figure 76. Cost by Transmission Availability in Continued Progress scenarios

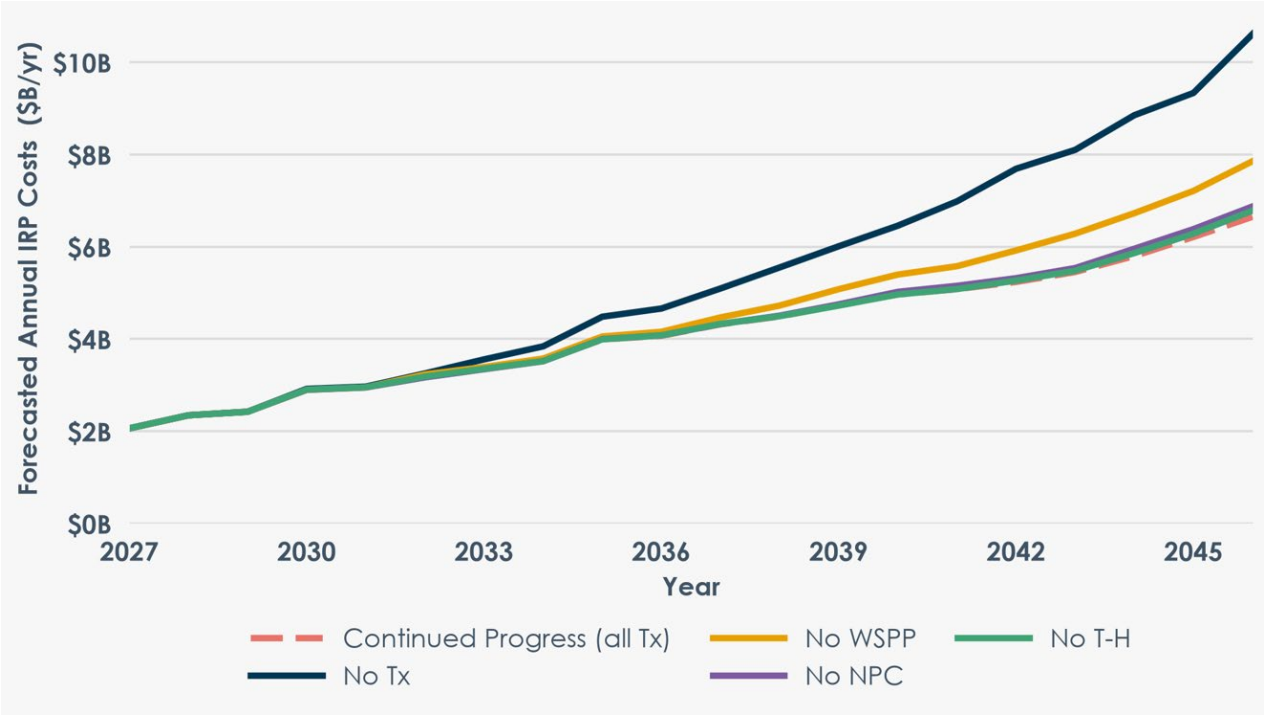
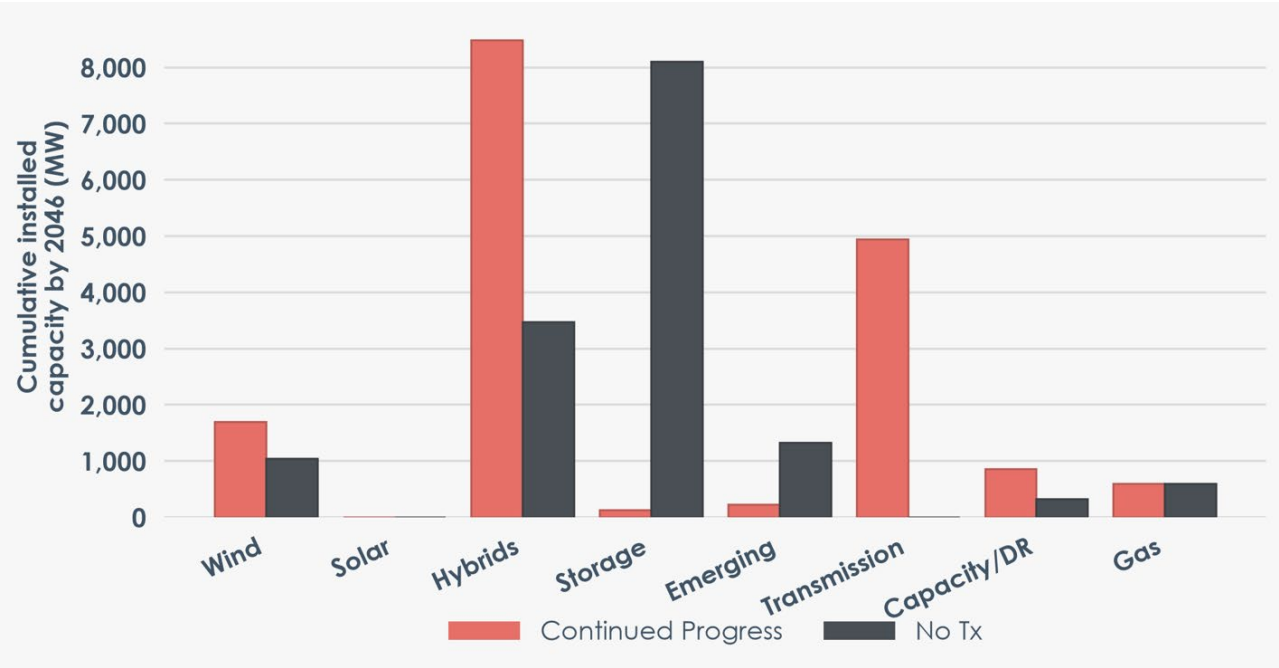


Figure 77. Resource Selection by Transmission Availability in Continued Progress Scenarios



7.4.5 Tax Credit Extension Scenarios

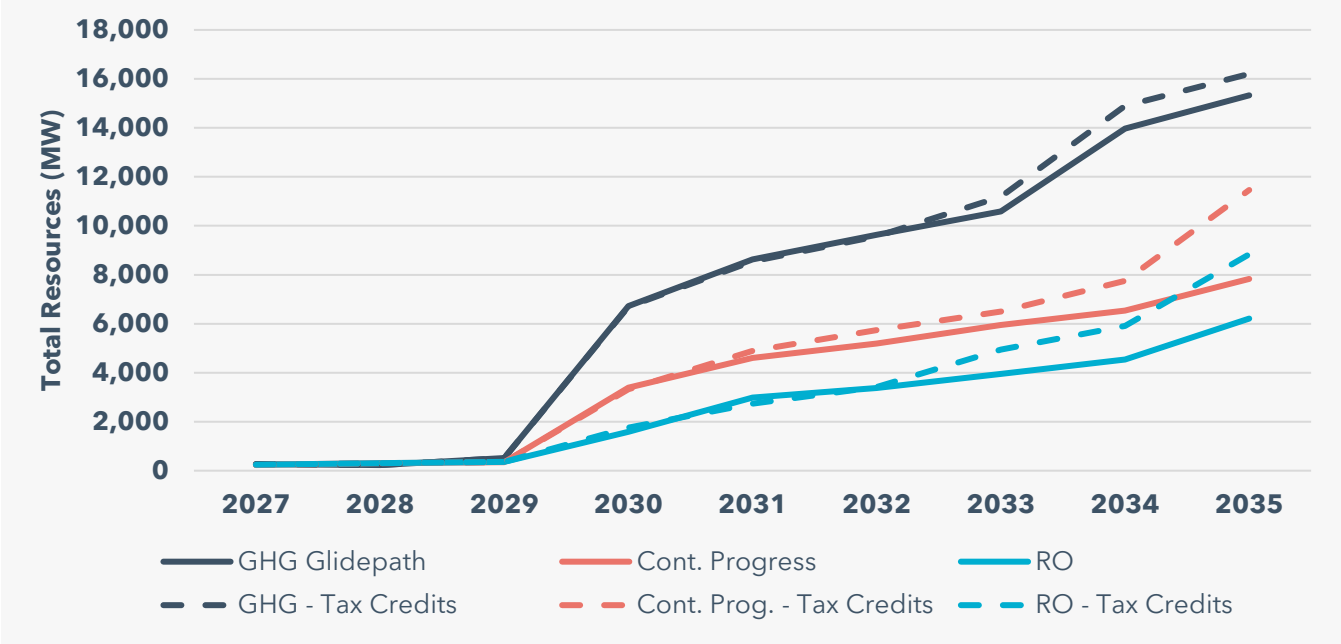
Under base case assumptions, renewable tax credits are assumed to sunset following the 2025 RFP FSL projects, significantly increasing resource costs beyond 2030. This assumption reflects the existing federal tax credit environment. Recognizing that there is a long history of federal tax extensions, the tax credit extension scenarios explore the impacts of tax credits being extended through the end of the planning horizon for all eligible renewable and storage resources. Detailed assumptions underlying the base case and tax credit extensions can be found in Section 3.2.1. Tax credit extension scenarios were considered across the three (3) regulatory environment structures (GHG Glidepath, Continued Progress, and Reliability Only).

Results show no significant change is called for in the action plan period, even when assuming credit extension through the entire planning horizon (Figure 78). However, tax credit extensions can be shown to contribute favorably to affordability outcomes, as seen in comparison of portfolio NPVRR results for base case results compared to those with tax credit extension (Figure 79).

Impact on resource additions in the GHG Glidepath scenarios are minor because the high resource needs result in the model having less flexibility to respond to the change in resource costs. In the Reliability Only scenario a larger impact on post-Action Plan resource additions can be seen, with the increase in total resource additions under the tax credit extension assumptions being driven largely by shifting to greater reliance on standalone wind resources and fewer hybrids. The extension of tax credits has a larger impact on standalone wind costs relative to hybrids which see a

smaller percentage decrease in their costs as a result of the storage portion of hybrids already having tax credits under base case assumptions.

Figure 78. Reference Case Total Resource Additions in Tax Credit Extension Scenarios



While extending renewable tax credits does not materially change which resources are selected in the action-plan window, tax credits meaningfully lower the expected cost of the resources the plan already calls for. On a reference-case 20-year NPVRR basis, extended credits reduce portfolio cost by approximately $8.5 billion in the GHG Glidepath scenario, $3.5 billion in the Reliability Only scenario, and $3.4 billion in the Continued Progress scenario. The savings are largest for the GHG Glidepath scenario because its buildout relies most heavily on the credit-eligible resources that the extended credits discount.

Figure 79. Reference Case 20-year IRP NPVRR of Tax Credit Extension Scenarios

7.4.6 State Reliability Metrics Scenario

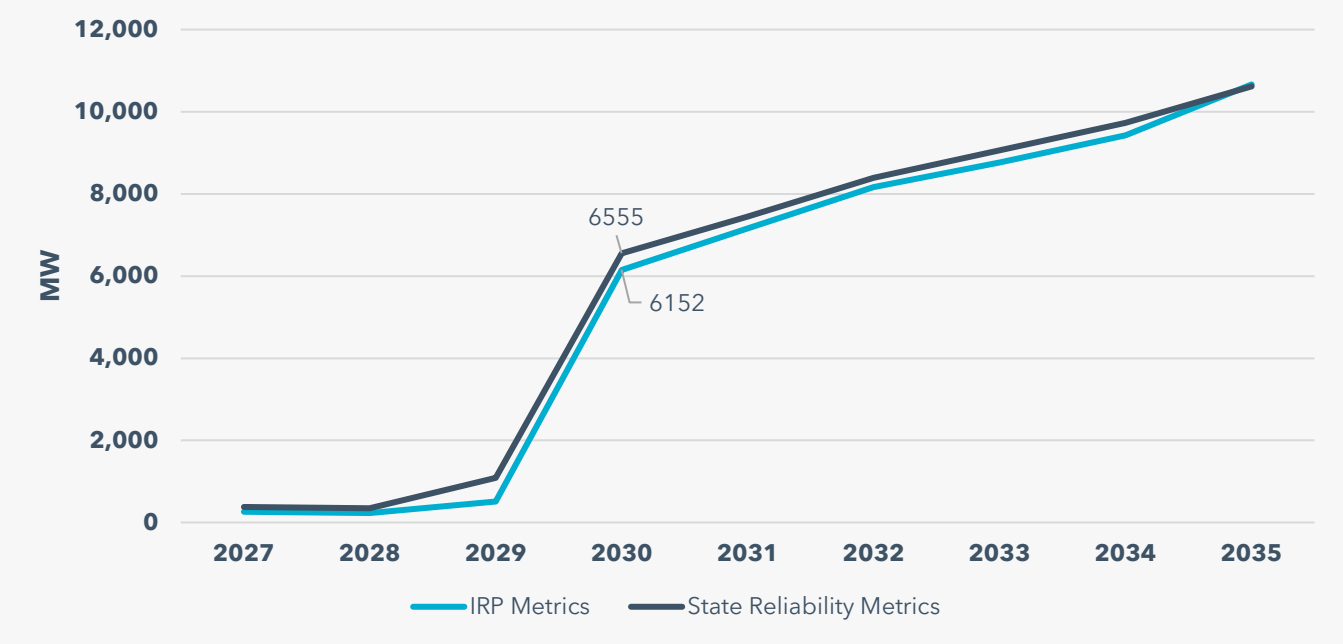
The State Reliability Metrics scenario models PGE's resource adequacy needs using alternative methods to PGE's standard resource adequacy modeling approach. State Reliability Metrics estimates of system capacity needs and proxy resource ELCCs are derived using Western Resource Adequacy Program (WRAP) methodologies. These methodologies are described in Appendix Section H.10. Capacity needs between IRP Methods and State Reliability Metrics have similar trends, as displayed in Appendix Section H.10.3, Figure 203. A comparison of ELCCs between the two (2) methodologies is displayed in Appendix Section H.10.4, Figure 204. IRP-WRAP ELCC Comparison shows WRAP based ELCCs tend to be less than those estimated with IRP Metrics methodologies. In all other assumptions, the State Reliability Metrics scenario is aligned with the GHG Glidepath scenario.

Portfolio results for the State Reliability Metrics scenario are compared against those estimated using IRP Metrics in Figure 80. Total resource additions for a scenario modeling the GHG Glidepath regulatory structure are shown to be very similar for the two (2) methodologies. In 2030, total resource additions in the State Reliability Metrics scenario are 382 MW (6%) greater than those produced with IRP Metrics.[120] The choice of methodology for estimating capacity need and proxy resource ELCC does not have a large impact on portfolio outcomes, suggesting that the total

[120] To allow for comparability across these two scenarios, the topside resource adjustments made to the GHG Glidepath portfolio for hourly emissions attainment are not included here.

resource additions in the GHG Glidepath portfolio is robust to choice of resource adequacy methods.

Figure 80. Reference Case Total Resource Additions for State vs IRP Reliability Metrics



7.5 Portfolio Scoring

In alignment with past IRPs and in accordance with new rules in OAR 860-090-0060(7)(i), PGE includes a summary table of various scoring metrics across scenarios analyzed. These metrics encompass both traditional cost and risk metrics as well as non-traditional metrics, which reflect feedback received from public processes to account for risks not captured in the traditional economic factors. In addition to the above, new to this CEP/IRP is a different view of cost and risk metrics conducted using PGE's new ARIA model. Together, the above metrics help shape an overview of the scenario analysis results to compare and contrast the costs and risks of different potential pathways ahead.

7.5.1 Enhanced Cost/Risk Assessment Tool

ARIA is an evolved portfolio valuation tool PGE developed for the 2026 CEP/IRP to enhance PGE's ability to assess risks associated with portfolio costs. Where ROSE-E constructs a least-cost resource buildout for each future, ARIA takes those buildouts and re-values each one across the set of evaluated futures, producing a full distribution of 20-year cost (NPVRR) outcomes for every candidate buildout rather than a single point estimate. Each buildout is scored on both its expected cost (the mean NPVRR across futures) and its cost risk (the variability of NPVRR across futures), and the buildout that best balances the two (2) is identified for each scenario.

To isolate the cost and risk of portfolio composition, ARIA holds the load forecast at its Reference level while varying market-price and technology-cost conditions across the future set; load-forecast

uncertainty is examined separately through the Core Growth Only scenarios and the load scenarios described in Chapter 6. Comparing scenarios on this basis (Figure 85) shows that the Reliability Only family carries the lowest expected cost and risk, the GHG Glidepath family the highest, and Continued Progress falls between them – far below the GHG Glidepath family on both dimensions and only a modest premium above Reliability Only, consistent with its favorable cost-to-emissions-reduction trade-off.

ARIA evaluates cost and risk by taking each scenario's ROSE-E resource buildout and re-valuing it across 111 constant-load futures – combinations of market-price (Section 6.6.2) and technology-cost assumptions (Section 6.6.3) with load held at its reference forecast – and computing the 20-year NPVRR of each. Each scenario is summarized by the mean of those NPVRRs (expected cost), their standard deviation (cost variability), and their 90th percentile (severity). Portfolios with low variability scores tend to provide more cost certainty and lessen the customer's exposure to higher-than-expected cost conditions. Portfolios with low severity scores tend to have less costly worst-case scenarios for customer cost impacts.

ARIA produces a distribution of portfolio cost outcomes rather than a single cost estimate, showing how each portfolio performs across favorable, adverse, and intermediate future conditions. It evaluates each portfolio using both expected cost and cost variability, which reflects the extent to which costs fluctuate across futures. A portfolio with a lower expected cost but substantially greater variability may therefore score less favorably than a portfolio with a similar expected cost and more stable outcomes. ARIA identifies the portfolios that provides the most cost-efficient balance between expected cost and cost risk.

This approach differs from prior practice in the treatment of the reference portfolio which had been the basis for selected portfolios. In the 2026 IRP, the reference portfolio, which is optimized for the Reference future, remains a candidate portfolio for selection but is no longer presumed to be the preferred outcome. When portfolios are re-valued across all 111 futures, the Reference portfolio may not provide the most favorable balance of expected cost and cost risk.

7.5.1.1 Summary of ARIA Analysis

The new framework introduced with ARIA recognizes that portfolios with the lowest expected cost may also exhibit substantial exposure to unfavorable future conditions, while portfolios that reduce risk may require additional investment and therefore have higher expected costs. As a result, portfolio selection is based on identifying portfolios that achieve an effective balance between these competing objectives. This analysis resulted in PGE selecting non-reference portfolios for both Continued Progress[121] and the HB 2021 Preferred Portfolio.

[121] As a result of final analytical procedures performed for the 2026 CEP/IRP, the optimal portfolio for the Continued Progress structure changed from the one PGE proposes in this IRP. PGE reviewed the resource buildout and costs associated with the final optimal portfolio compared to the portfolio utilized in analysis for the IRP and identified the difference to be immaterial (less than 0.1% in change in costs). The change in resource buildout was also insignificant and determined not to have an impact on the near-term Action Plan or long-term resource strategy. As a result, the analysis included in the IRP was not updated to reflect the absolute optimal portfolio.

Figure 81. ARIA Results for the 111 Portfolios under the GHG Glidepath Scenario

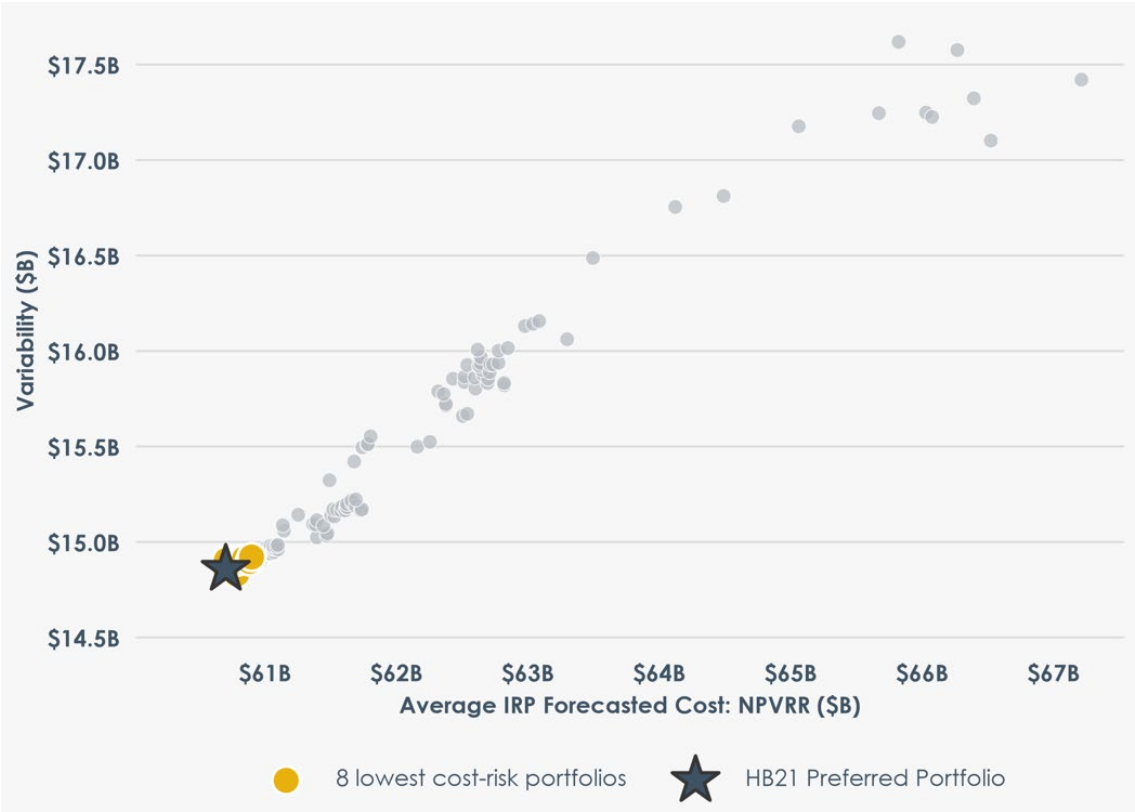


Figure 81 above shows all 111 future portfolios constructed under the GHG Glidepath scenario to meet a variety of conditions and possible futures, and highlights the eight (8) portfolios with the lowest cost-risk combination when evaluated in ARIA. These results identified that a non-reference case portfolio performed better on a cost and risk basis when compared to the reference case portfolio. As a result, the non-reference case portfolio was identified as the HB 2021 Preferred Portfolio, which is required by rules to achieve exact emission reduction targets outlined in HB 2021, further discussed in Section 7.5.2 and 7.6.

Figure 82. ARIA Results for the 111 Portfolios under the Continued Progress Scenario

The above figure shows a similar analysis for the Continued Progress scenario. In the case of the Continued Progress scenario there is a requirement of at least 6% incremental spend on renewable resources—and so the portfolios that do not achieve this are considered ineligible (the red dots in the bottom left). These results identified that a non-reference case portfolio performed better on a cost and risk basis when compared to the reference case portfolio. As a result, the non-reference case portfolio was identified as the selected Continued Progress Portfolio, further discussed in Section 7.5.2 and 7.6.1.

In both the GHG Glidepath and Continued Progress scenario, ARIA results indicate that the most cost- and risk-efficient buildouts are tightly clustered. In the Continued Progress scenario, the eight best-scoring buildouts fall within roughly 0.08% of one another. The GHG Glidepath scenario is similarly tight at 0.34% difference between the top eight (8). Comparison of portfolio builds across the tightly clustered top-performing buildouts reveals largely consistent resource selections. This consistency provides support for the robustness of the resource buildouts presented in the HB 2021 Preferred Portfolio and Continued Progress portfolio, which serve as the basis for the Near-Term Action Plan.

7.5.1.2 Comparison of Selected Portfolio Buildouts to Reference Case Buildouts

Relative to each scenario's reference-case build, the selected Continued Progress portfolio shifts toward incremental energy storage and emerging clean-firm capacity while trimming a modest amount of wind and hybrid capacity, whereas the selected HB 2021 Preferred Portfolio from the GHG Glidepath scenario shifts away from standalone storage (approximately 500 MW) and toward additional solar.

This is the result of two (2) main drivers: the diminishing marginal value of firm and flexible capacity over the planning horizon and access to transmission.

Diminishing marginal value of firm and flexible capacity: In the reference build of the Continued Progress portfolio, there is a minimal amount of standalone storage selected (129 MW, with most of its storage embedded within hybrid resources). Given that the first increments of dedicated storage and clean-firm capacity provide substantial, low-cost reliability and price-hedging value, the selected Continued Progress portfolio (the build that optimizes costs and risks) adds additional volumes of storage and clean-firm capacity.

Under the GHG Glidepath Scenario, the reference build already carries roughly 5,000 MW of standalone storage. At that volume, continuing to add more storage contributes little additional risk mitigation while continuing to carry significant capital-cost exposure, so the selected GHG Glidepath build (which ultimately serves as the HB 2021 Preferred Portfolio) reduces the volume of storage resources compared to the reference build in favor of lower-cost energy. In both scenarios the underlying preference is identical—to minimize the risk adjusted average cost of the portfolio - but that single preference points in opposite directions when applied to a portfolio with minimal volumes of storage versus a portfolio with significant volumes of storage.

Transmission access: The second driver is transmission access, which explains why the HB 2021 Preferred Portfolio can substitute toward solar, and the Continued Progress portfolio cannot. The incremental solar selected in the HB 2021 Preferred Portfolio when compared to the reference build is an out-of-region (Nevada) resource that depends on new transmission expansion which the HB 2021 Preferred Portfolio builds, and the Continued Progress portfolio does not. Because the remote generation and the transmission required to deliver it are only economic as a bundle, and because the Continued Progress Portfolio does not require as much additional out-of-region renewable energy to achieve full HB 2021 emission reduction targets, neither the transmission line nor the associated solar are cost effective in that scenario. The Continued Progress portfolio's risk-based improvements are consequently limited to the resources available on existing interconnection—storage and clean-firm capacity—while its solar continues to enter only as a component of in-region hybrid resources. When considering the results of both portfolios, the trends reflect a single, consistent risk-based tilt toward solar and firm capacity and away from marginal wind.

Figure 83 and Figure 84 show the difference in volumes of key resource types selected in the selected buildout compared to the reference case buildout for both the Continued Progress scenario and GHG Glidepath scenario.

Figure 83. Continued Progress Resource Buildout Change

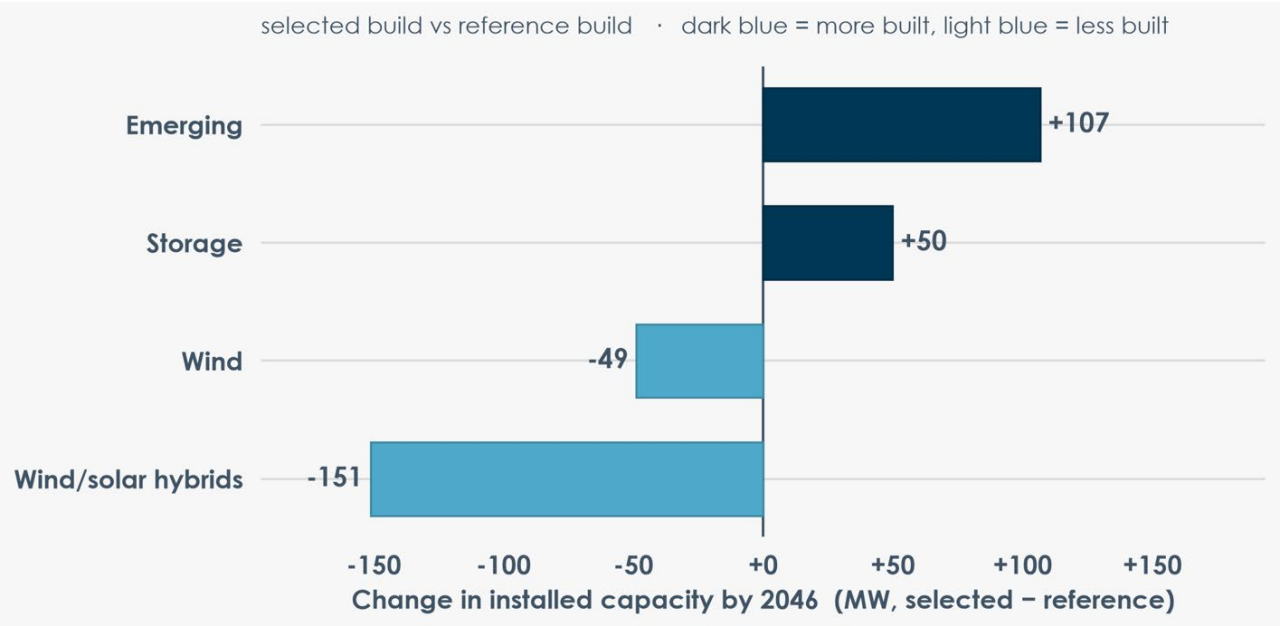
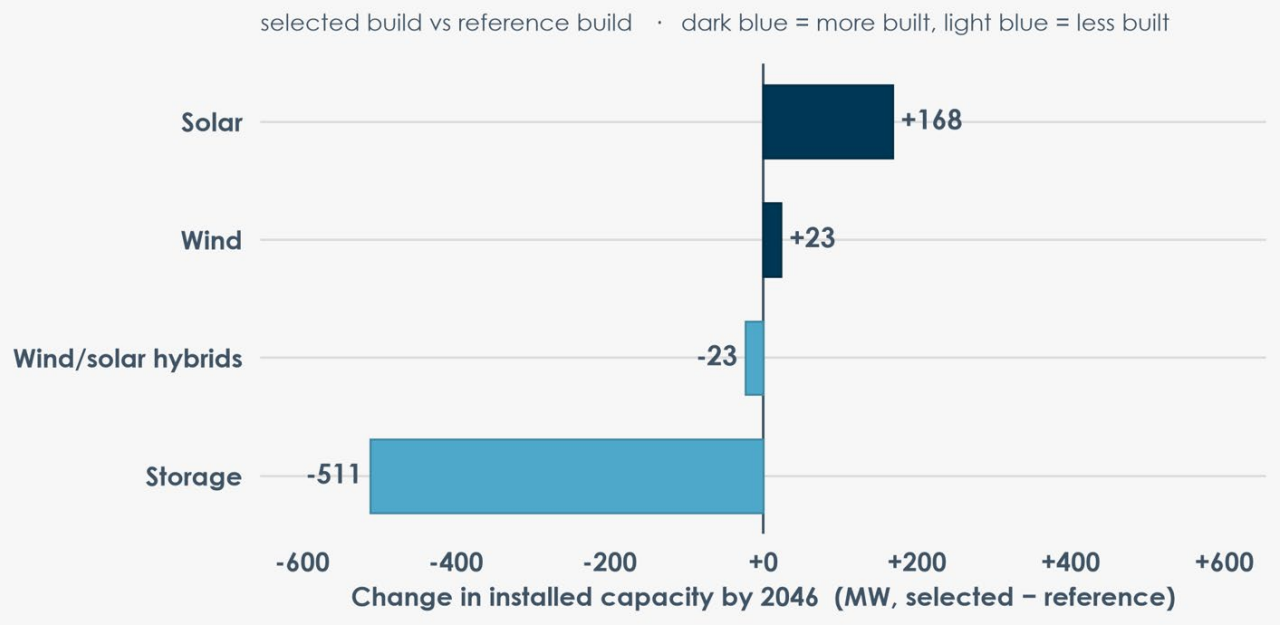


Figure 84. GHG Glidepath Resource Buildout Change



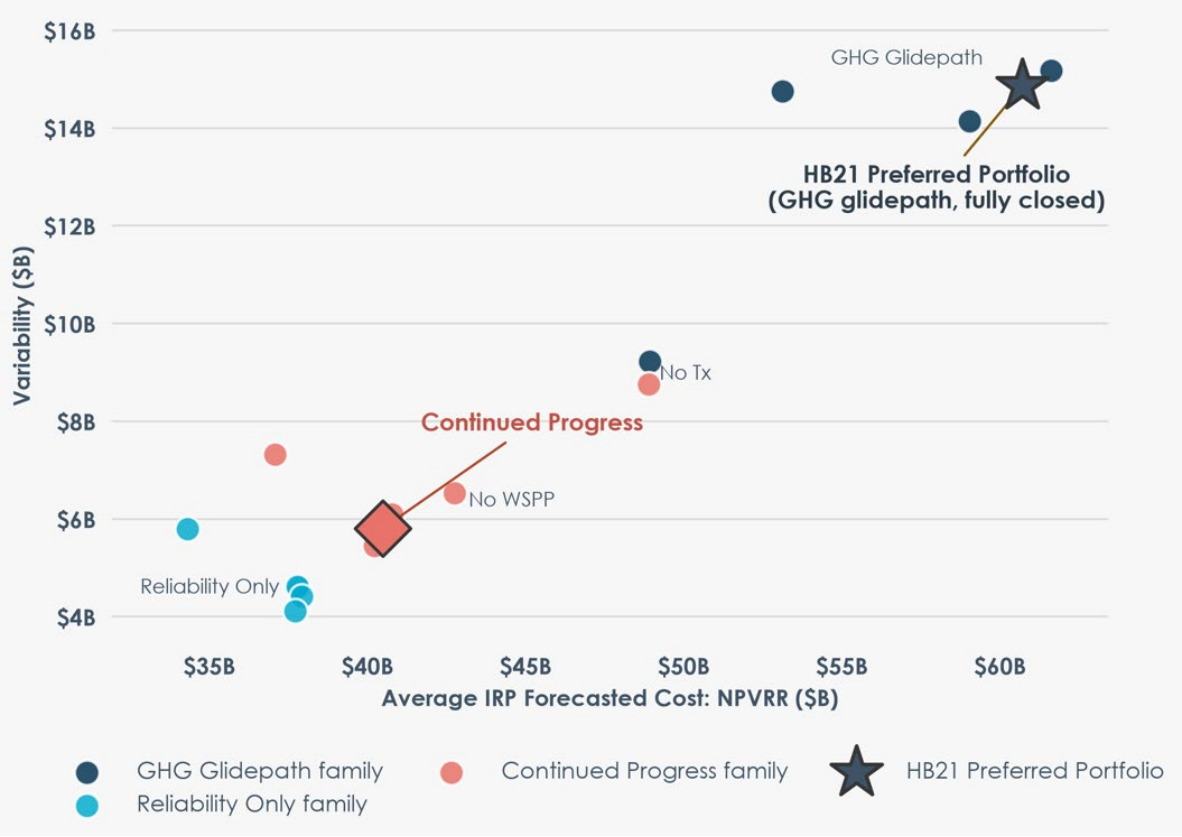
7.5.2 Summary of Portfolio Scoring

Traditionally, PGE has conducted a multi-stage scoring process to evaluate portfolios and to arrive at a Preferred Portfolio. This process has combined evaluation across the traditional cost and risk metrics with consideration of non-traditional metrics, allowing PGE to meet least-cost, least-risk planning guidelines while reflecting the company's values and the values expressed by stakeholders within public processes. Since then, adoption of HB 2021, CEP guidelines, and newly

adopted CEP/IRP rules have become more prescriptive in requiring the Preferred Portfolio to represent compliance with the GHG emissions targets of HB 2021, on a planning basis. It is important to note that rules require the IRP Preferred Portfolio to achieve the emissions reductions targets set forth in ORS 469A.410. However, portfolio scorings across traditional and non-traditional metrics remain informative and PGE has included reference results for all scenarios analyzed in Table 26. The HB 2021 Preferred Portfolio and Continued Progress Portfolio buildout results identified in the preceding section's ARIA model risk-efficient analysis are also included in the summary scoring table for comparisons.

As discussed in Chapter 1, and evidenced by ARIA results, the HB 2021 Preferred Portfolio that achieves exact emissions reductions targets as outlined in HB 2021 requires significantly higher costs and risks than all other portfolios reviewed, refer to Figure 85 below. As a result, the Continued Progress Portfolio was utilized, along with the HB 2021 Preferred Portfolio, to inform the near-term Action Plan.

Figure 85. Costs and Risks of HB 2021 Preferred Portfolio Compared to Others for the Full Planning Horizon



7.5.2.1 Traditional Scoring Metrics

The scoring metrics of cost, variability, and severity are updated compared to what was used in the past two (2) IRPs and are further described in Table 24. They reflect the additional detail available using the ARIA model.

Table 24. Traditional Portfolio Scoring Metrics

Metric	Description	Unit
Cost	Average net present value of revenue requirement (NPVRR), calculated as the average cost of each portfolio for each of the 333 future scenarios for the analysis timeline (2027-2046). 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 2026$
Variability	Standard deviation of NPVRR across all futures for each of the 333 portfolios. This metric captures the potential variation in cost outcomes across futures. Portfolios with low variability scores tend to provide more cost certainty.	Million 2026$
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 2026$

7.5.2.2 Non-Traditional Scoring Metrics

For this CEP/IRP, PGE has also included a range of non-traditional scoring metrics to compare across the scenarios analyzed.

Another ARIA metric reported in the scoring table is the risk-adjusted cost of each buildout: the expected 20-year NPVRR cost shown plus its variability (or standard deviation) shown across the evaluated futures (in Million 2026$). A lower value indicates a buildout that is both less costly on average and less exposed to cost variability across futures. This single-value ARIA metric combines expected cost and risk of its variability into one score. As described in the preceding section, this metric was used to identify the most risk-efficient buildout within the GHG Glidepath scenario as the Preferred Portfolio.

In response to new rule OAR 860-090-0060(7)(g)(B), PGE also included in the scoring a near-term cost estimate (in Million 2026$) of the sum of the total estimated costs for the first five years of the 20-year planning horizon for each scenario. As with the 20-year cost, the near-term cost is also discounted back to 2026 dollars (NPVRR). This metric represents the mid-point assumptions used for new resources, assuming 50/50 ownership by PGE/PPA[122] (which impacts new resource costing in the analysis). See Section 7.7 for more on annual cost estimates.

The pCBI scoring metrics represent a substantially more thorough and detailed approach to measuring the level of community benefits provided by each scenario than has been used in IRP

[122] Transmission Expansion Options and Market Transactions have a single expected cost instead of a PPA/PGE split.

analysis prior to the passage of HB 2021. pCBIs are unitless indicators that accrue for each MW of eligible resource that is added in each portfolio. A detailed description of the pCBI development, including a mapping of which proxy resources generate each of the pCBIs, is provided in Appendix D.

Table 25. Portfolio Community Benefits Indication (pCBI) Metrics

Metric	Description
pCBI1 **Economic Impacts**	Economic development, increased access to jobs, economic well-being, increased productivity
pCBI2 **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
pCBI3 **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)
pCBI4 **Resilience and Reliability**	Improved grid resiliency; increased resilience/reliability in environmental justice communities, including reduced recovery time and frequency of outages
pCBI5 **Environmental Impacts**	Reduced air emissions, including CO2 and criteria pollutants

Additional non-traditional scoring metrics focus on GHG emissions reductions and resource buildout results of portfolio analysis modeling. Near-term metrics represent through the Action Plan window while long-term metrics represent the full 20-year time horizon. These metrics aim to help understand progress on HB 2021 targets, as well as the implications for the system (and costs) in working toward them. For example, while all scenarios add clean energy to the system in the near-term, some more than others require substantial transmission buildout over time to access resources.

Table 26. Portfolio Scoring

			Traditional Metrics (20yr NPVRR)			Non-Traditional Metrics										
Future	Regulatory Environment	Scenario Name	Cost	Variability	Severity	ARIA Cost-Risk Metric	Near-Term Costs sum of 2027-31	pCBI1	pCBI2	pCBI3	pCBI4	pCBI5	2030 Retail GHG Mill. MT CO2e	2032 Capacity Builds GW	2032 Wind & Solar GW diff from Pref. Port.	2046 Transmission GW diff from Pref. Port.
Reference Case Results			(costs in Millions 2026$)													
RRRR	**Reliability Only**	**RO**	**$ 37,821**	**$ 4,596**	**$ 43,653**	**$ 42,417**	**$ 9,865**	**12,378**	**305**	**305**	**16,123**	**14,402**	**5.45**	**3.3**	**-66%**	**-18%**
RRRR	Reliability Only	RO - Hydro	$ 37,781	$ 4,617	$ 43,639	$ 42,398	$ 9,858	13,114	275	275	14,920	13,474	5.28	3.0	-72%	-23%
RRRR	Reliability Only	RO - Colstrip	$ 37,484	$ 4,418	$ 43,081	$ 41,902	$ 9,862	12,175	300	300	16,052	14,360	7.61	2.6	-77%	-18%
RRRR	Reliability Only	RO - Colstrip - Hydro	$ 37,275	$ 4,113	$ 42,479	$ 41,388	$ 9,849	11,718	297	297	15,237	13,848	7.44	2.2	-80%	-18%
RRRR	Reliability Only	RO - Tax Credits	$ 34,313	$ 5,794	$ 41,921	$ 40,107	$ 9,741	12,438	267	267	14,043	15,357	4.85	3.4	-62%	-18%
RRRR	**HB2021-ContProg**	**Cont. Progress**	**$ 40,492**	**$ 5,809**	**$ 47,905**	**$ 46,301**	**$ 10,300**	**12,271**	**277**	**277**	**15,170**	**15,816**	**3.41**	**5.2**	**-45%**	**-18%**
RRRR	HB2021-ContProg	Cont. Prog. - Hydro	$ 40,232	$ 5,448	$ 47,190	$ 45,680	$ 10,242	11,904	273	273	15,246	15,963	3.35	4.2	-54%	-18%
RRRR	HB2021-ContProg	Cont. Prog. - Tax Credits	$ 37,075	$ 7,325	$ 46,661	$ 44,400	$ 10,096	13,866	249	249	15,568	17,841	3.17	5.7	-30%	0%
RRRR	HB2021-ContProg	No Transmission	$ 48,886	$ 8,751	$ 60,383	$ 57,637	$ 10,322	15,771	355	355	19,076	19,116	3.54	5.7	-47%	-100%
RRRR	HB2021-ContProg	No WSPP	$ 42,753	$ 6,535	$ 51,306	$ 49,288	$ 10,292	11,643	279	279	14,477	14,977	3.37	4.5	-53%	-68%
RRRR	HB2021-ContProg	No TH	$ 40,612	$ 5,806	$ 48,022	$ 46,417	$ 10,299	11,368	277	277	15,115	15,526	3.40	4.8	-50%	-27%
RRRR	HB2021-ContProg	No NPC	$ 40,776	$ 6,095	$ 48,566	$ 46,871	$ 10,292	12,348	275	275	15,810	16,147	3.37	5.1	-45%	-23%
RRRR	**HB2021-Glidepath**	**GHG Glidepath**	**$ 61,620**	**$ 15,183**	**$ 81,801**	**$ 76,803**	**$ 11,296**	**21,175**	**296**	**296**	**31,750**	**30,837**	**1.62**	**9.6**	**7%**	**0%**
RRRR	HB2021-Glidepath	GHG Glidepath - Hydro	$ 59,040	$ 14,139	$ 77,853	$ 73,179	$ 11,115	20,210	294	294	30,856	30,377	1.62	8.5	-3%	0%
RRRR	HB2021-Glidepath	GHG - Tax Credits	$ 53,129	$ 14,747	$ 72,830	$ 67,876	$ 10,888	21,083	296	296	32,454	31,709	1.62	9.6	6%	0%
RRRR	HB2021-Glidepath	State RA	$ 48,927	$ 9,228	$ 60,690	$ 58,155	$ 11,360	18,307	368	368	26,565	25,278	1.78	8.4	-11%	0%
Selected Portfolio Results																
HHRR	**HB2021-ContProg**	**Cont. Progress Portfolio**	**$ 40,470**	**$ 5,832**	**$ 47,887**	**$ 46,302**	**$ 10,297**	**11,907**	**276**	**276**	**14,973**	**15,570**	**3.39**	**5.2**	**-44%**	**-18%**
RHHN	**HB2021-Glidepath**	**Preferred Portfolio**	**$ 60,702**	**$ 14,860**	**$ 80,479**	**$ 75,562**	**$ 11,301**	**21,720**	**296**	**296**	**30,213**	**29,491**	**1.62**	**9.0**	**6.8**	**6.0**

Table 27. Portfolio Scoring for Core Growth Only Scenarios

			Traditional Metrics (20yr NPVRR)			Non-Traditional Metrics										
Future	Regulatory Environment	Scenario Name	Cost	Variability	Severity	ARIA Cost-Risk Metric	Near-Term Costs sum of 2027-31	pCBI1	pCBI2	pCBI3	pCBI4	pCBI5	2030 Retail GHG Mill. MT CO2e	2032 Capacity Builds GW	2032 Wind & Solar GW	2046 Transmission GW
Core Growth Only (CGO)			(costs in Millions 2026$)													
RRRR	Reliability Only	RO - CGO	$ 32,987	$ 2,954	$ 36,871	$ 35,941	$ 9,758	4,122	55	55	4,752	4,953	4.82	1.8	1.2	0.5
RRRR	Reliability Only	RO - CGO - Colstrip	$ 32,855	$ 2,927	$ 36,784	$ 35,782	$ 9,801	4,105	40	40	4,635	4,879	6.73	1.6	1.0	0.5
RRRR	Reliability Only	RO - CGO - Hydro	$ 32,929	$ 2,850	$ 36,580	$ 35,779	$ 9,760	3,631	40	40	3,483	3,848	4.65	1.6	1.0	0.0
RRRR	Reliability Only	RO - CGO - Colstrip - Hydro	$ 32,736	$ 2,834	$ 36,428	$ 35,570	$ 9,807	3,631	40	40	3,483	3,848	6.36	1.5	1.0	0.0
RRRR	HB2021-ContProg	Cont. Prog. - CGO	$ 35,336	$ 3,600	$ 40,089	$ 38,936	$ 10,162	4,876	14	14	5,001	7,223	2.80	3.4	2.6	1.5
RRRR	HB2021-ContProg	Cont. Prog. CGO Hydro	$ 35,321	$ 3,450	$ 39,832	$ 38,771	$ 10,150	3,968	29	29	4,530	6,264	2.78	3.1	2.3	0.5
RRRR	HB2021-Glidepath	GHG Glidepath - CGO	$ 47,075	$ 7,971	$ 57,344	$ 55,045	$ 10,719	12,257	68	68	16,772	16,856	1.62	5.7	4.6	4.9
RRRR	HB2021-Glidepath	GHG CGO Hydro	$ 44,962	$ 6,964	$ 54,068	$ 51,926	$ 10,571	11,460	68	68	15,461	15,451	1.62	5.2	4.2	4.9

7.6 HB 2021 Preferred Portfolio

The Preferred Portfolio is required by rules to achieve the emissions reduction targets outlined in HB 2021. As a result, PGE determined the GHG Glidepath scenarios as eligible for Preferred Portfolio selection. Based on the insights gained through comparison of the wide range of scenarios analyzed in the portfolio scoring process, a specific buildout identified as least-cost, least-risk and compliant with emissions reductions targets was identified as the HB 2021 Preferred Portfolio (described above in Section 7.5 and below). This portfolio also meets RPS obligations. The findings from the HB 2021 Preferred Portfolio are used to inform the Action Plan, described in Section 2.1.

ARIA's risk-based assessment informed the composition of the HB 2021 Preferred Portfolio. Among the ways to close the HB 2021 emissions gap, ARIA found that a phased combination of near-term hybrid resources and later emerging clean-dispatchable capacity achieves the target at a lower expected cost and comparable risk than approaches relying on a single emerging technology. The methodology for this construction is described in Appendix Section H.2.2.5. Within that combination, ARIA identified the risk-efficient buildout—the one that best balances expected cost and cost variability across futures—which forms the basis of the HB 2021 Preferred Portfolio. Due to this selection refinement, the HB 2021 Preferred Portfolio is not identical to the previously discussed GHG Glidepath; which is the buildout under reference conditions. It is instead the l cross all futures.

ARIA further finds that the most cost- and risk-efficient buildouts eligible for selection as the HB 2021 Preferred Portfolio are tightly clustered—the eight best-scoring buildouts fall within about 0.55% of one another, indicating that the near-term resource additions in the Action Plan window are robust to the uncertainties captured in the futures. ARIA's risk decomposition also indicates that a portion of the portfolio's cost risk could be reduced by shifting some standalone wind toward solar and firm capacity; PGE will weigh this insight, alongside deliverability and siting considerations, in resource solicitation and the Near-Term Action Plan.

The HB 2021 Preferred Portfolio resource buildout through the end of the Action Plan window in 2032 is shown in Table 28. Additional details on the composition of the HB 2021 Preferred Portfolio through 2036 can be seen in Figure 86. The HB 2021 Preferred Portfolio adds 9,036 MW of total resources and 1,270 MW of transmission through 2032. The portfolio relies heavily on hybrid resources and standalone wind to meet needs through this period, adding 2,665 MW of hybrid wind, 2,138 MW of standalone wind, 1,956 MW of hybrid solar, and 1,983 MW of hybrid batteries. Off-system resources are comprised of a mix of resources with firm transmission and resources accessed using non-firm transmission inventory.

Resource additions reported in Table 28 include the resources added in ROSE-E as well as the additional resources added through iterative analysis in the Aurora PZM hourly emissions modeling process to exactly comply with HB 2021 emissions targets on an hourly-planning basis. Detailed methodology and results of the hourly emissions analysis and associated portfolio resource adjustments can be found in Appendix Section H.2.2.5. Detailed methodology and results of the hourly emissions analysis and associated portfolio resource adjustments can be found in Appendix Section H.2.2.5. About 11% (1008 MW) of the resources added through 2032 are a result of the

hourly emissions adjustment analysis. This includes 432 MW of hybrid wind, 288 MW of hybrid solar, and 288 MW of hybrid batteries. Because hourly emissions-reduction resources are added to the portfolio post-ROSE-E analysis, they are not subject to the transmission constraints enforced in portfolio analysis.

The portfolio also includes 253 MW of VPP resources, 27 MW of CBREs, and 11 MWa of NCE EE. VPP resources include a mix of resource types like DR programs and DSG, and resource type breakdowns and key findings regarding VPP resources are discussed in detail in Section 7.10.

Table 28. Cumulative Resource Buildout in the HB 2021 Preferred Portfolio (MW)

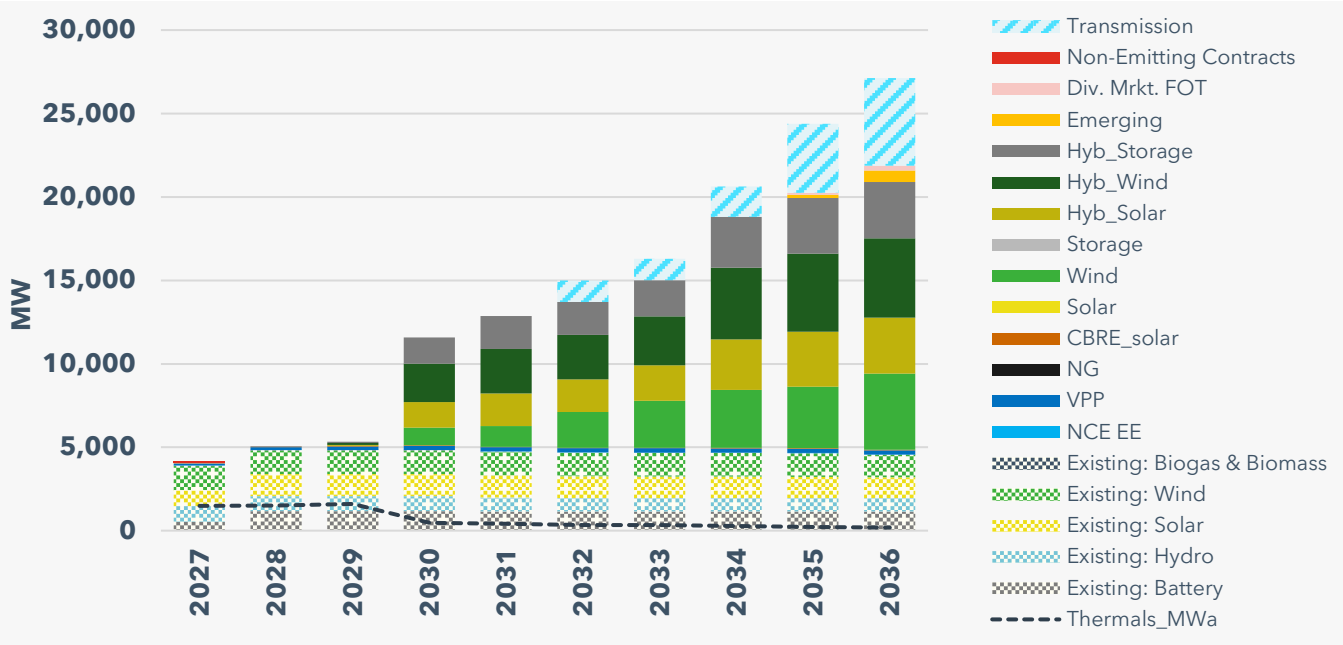
	2027	2028	2029	2030	2031	2032
Hybrid Battery	27	27	94	1565	1983	1983
Standalone Wind (Firm Tx)	0	0	0	42	42	940
Hybrid Wind (Firm Tx)	0	0	100	2051	2051	2051
Standalone Wind (NF Tx)	0	0	0	1009	1198	1198
Hybrid Wind (NF Tx)	0	0	0	254	614	614
Hybrid Solar (Firm Tx)	0	0	67	1368	1547	1547
Hybrid Solar (NF Tx)	0	0	0	170	409	409
NCE EE	11	11	12	12	12	13
VPP	99	165	213	249	252	253
CBRE	27	27	27	27	27	27
Total New Resources	266	230	513	6747	8136	9036
Transmission	0	0	0	0	0	1270

Transmission upgrades and expansion are an important component of the HB 2021 Preferred Portfolio, unlocking access to multiple GWs of off-system renewables, hybrids, and front-office transactions for capacity that are essential for constructing a reliable and decarbonized portfolio. Throughout the planning horizon, 6,045 MW of transmission is added to the portfolio (Table 29).

Table 29. Transmission Additions in the HB 2021 Preferred Portfolio (MW)

	2032	2034	2035	2036	2039
Warm Springs Power Pathway - Circuit 1	1000				
North Plains Connector	270				
Harborton-Trojan #3Harborton-Trojan #3		545			
Warm Springs Power Pathway - Circuit 2			2000		
Colstrip to Ashe Upgrade			330		
Cascade Renewables				1100	
SWIP North					400
Boardman to Hemmingway					400

Figure 86. Resource Mix of the HB 2021 Preferred Portfolio



7.6.1 Continued Progress Portfolio

In addition to the HB 2021 Preferred Portfolio, the insights gained through portfolio analysis and the portfolio scoring process allowed PGE to identify a second portfolio to be used to inform the Action Plan. The Continued Progress Portfolio was selected for this purpose because it represents an option that allows PGE to maintain reliability while continuing to make progress toward HB 2021 GHG emissions reductions targets, with fewer resource additions and with lower costs than the HB 2021 Preferred Portfolio. As highlighted in Section 7.4.1 above, the Continued Progress Portfolio offers a planning option with a compelling combination of emissions reductions and cost that substantially improves on the emissions outcomes of the Reliability Only portfolio, for only a fraction of the cost premium of the GHG Glidepath portfolio. As with the HB 2021 Preferred Portfolio, ARIA was used to refine the selection for the Continued Progress portfolio to the buildout with the least-cost and least-risk across all 111 futures.

The Continued Progress resource buildout through the end of the Action Plan window in 2032 is shown in Table 30. Additional details on the composition of the Continued Progress portfolio through 2036 can be seen in Figure 87. The Continued Progress portfolio adds 5,172 MW of total resources and 1,000 MW of transmission through 2032. The Continued Progress Portfolio requires 43% fewer resource additions through the Action Plan window, a direct result of building renewables to continue emissions reduction progress but not fully constraining the model to achieve the emissions reductions targets required by HB 2021. This finding is critical as PGE forms a path forward that balances the execution and affordability risks with the significant volume of resource additions identified in the HB 2021 Preferred Portfolio.

Similar to the HB 2021 Preferred Portfolio, the Continued Progress Portfolio relies heavily on hybrid resources to meet needs through this period, adding 1,550 MW of hybrid wind, 1,034 MW of hybrid solar, and 1,034 MW of hybrid batteries. The Continued Progress Portfolio also adds a substantial quantity of 248 MW of VPP resources, compared to 253 MW in the HB 2021 Preferred Portfolio. A combination of lower needs than the HB 2021 Preferred Portfolio and access to additional resources results in notably different outcomes for NCE EE (1 MWa) and CBREs (zero MW) in the Continued Progress Portfolio. The Continued Progress Portfolio includes 137 MW of the available 200 MW of natural gas contracts through 2032.

Table 30. Cumulative Resource Buildout in the Continued Progress Portfolio (MW)

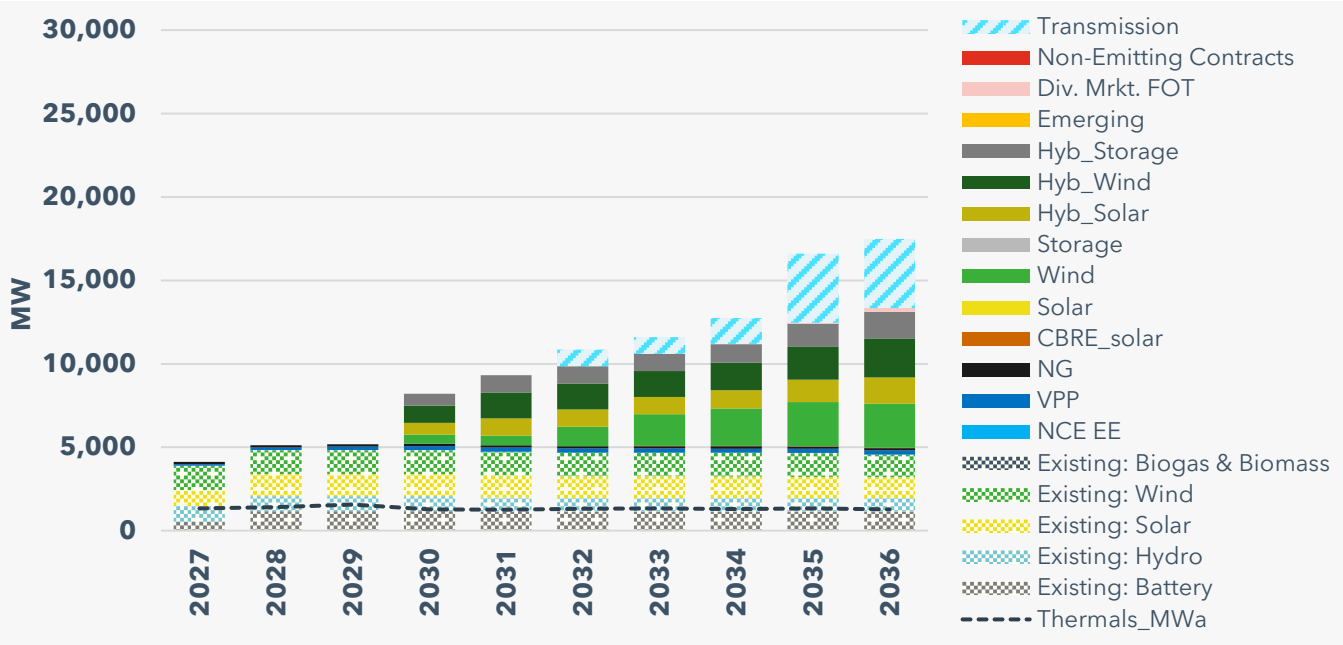
	2027	2028	2029	2030	2031	2032
Hybrid Battery	0	0	0	701	1034	1034
Standalone Wind (Firm Tx)	0	0	0	543	543	1132
Hybrid Wind (Firm Tx)	0	0	0	1051	1550	1550
Standalone Wind (NF Tx)	0	0	0	0	36	36
Hybrid Solar (Firm Tx)	0	0	0	701	1034	1034
NCE EE	0	0	0	1	1	1
VPP	96	161	208	243	247	248
Natural Gas	137	137	137	137	137	137
Total New Resources	233	298	345	3377	4582	5172
Transmission	0	0	0	0	0	1000

Just as in the HB 2021 Preferred Portfolio, transmission upgrades and expansion are an important component of the Continued Progress Portfolio. Throughout the planning horizon, 4,945 MW of transmission is added to the portfolio (Table 31). The Continued Progress and HB 2021 Preferred Portfolio add many of the same transmission options, with WSPP circuits 1 and 2, North Plains Connector, Harborton-Trojan #3, the Colstrip to Ashe upgrade, and Boardman to Hemmingway appearing in both portfolios. WSPP circuit 1, North Plain Connector, and Harborton-Trojan #3, specifically, are all selected relatively early in the planning horizon in both portfolios and are included in the Action Plan.

Table 31. Transmission Additions in the Continued Progress Portfolio (MW)

	2032	2034	2035	2039
Warm Springs Power Pathway - Circuit 1	1000			
Harborton-Trojan #3Harborton-Trojan #3		545		
North Plains Connector			270	
Warm Springs Power Pathway - Circuit 2			2000	
Colstrip to Ashe Upgrade			330	
Gateway				400
Boardman to Hemmingway				400

Figure 87. Resource Mix of the Continued Progress Portfolio

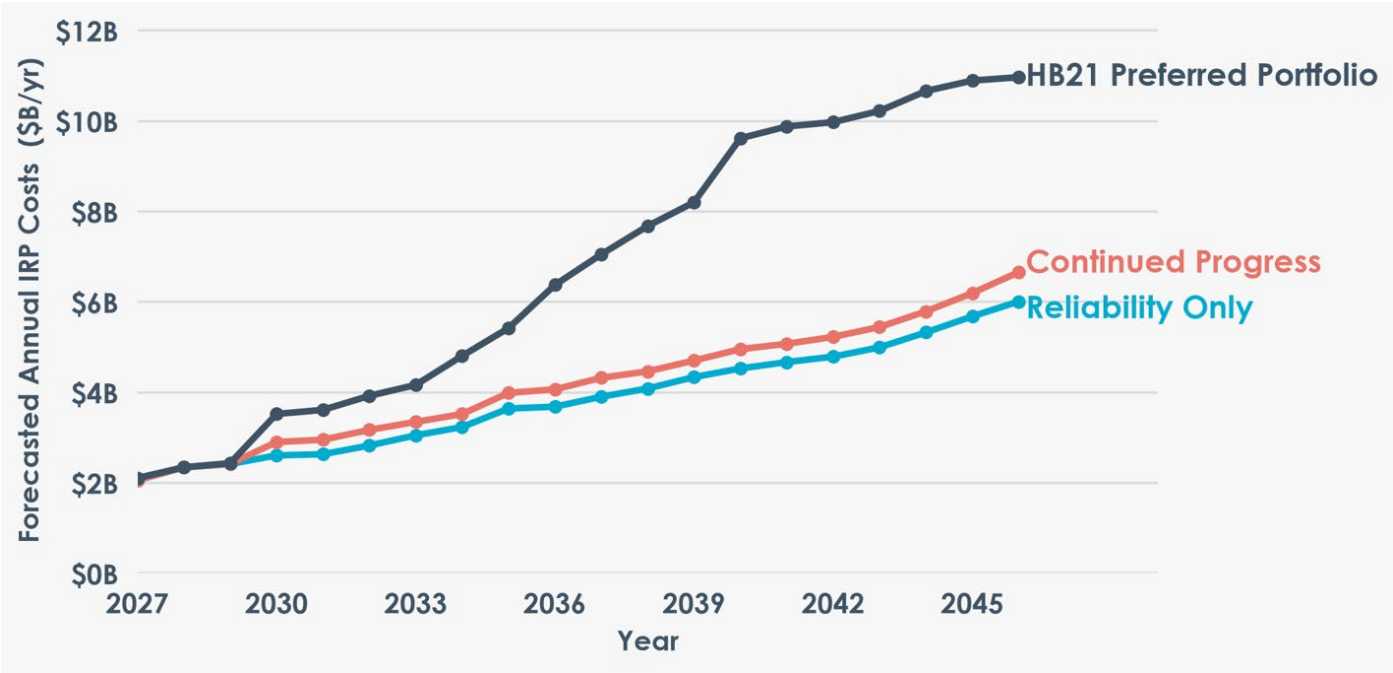


7.7 Yearly Cost Estimates

Figure 88 presents the annual costs of the HB 2021 Preferred Portfolio over the 2027–2046 planning horizon, in 2026 dollars. Annual costs are built up from the HB 2021 Preferred Portfolio's selected buildout evaluated at the reference future and broken out into their principal components: the annualized cost of new resource builds, the market energy value of new resources (a credit that offsets cost), the fixed and variable costs of the existing portfolio, and capacity/energy fill and firm-length adjustments. The net cost rises from approximately $3.9 billion in 2032 (the end of the Action Plan window) to approximately $11.0 billion in 2046, reflecting the resources added to achieve the HB 2021 emissions glidepath. Over the first five years (2027–2031), the cumulative cost of the HB 2021 Preferred Portfolio is approximately $14.0 billion nominally.

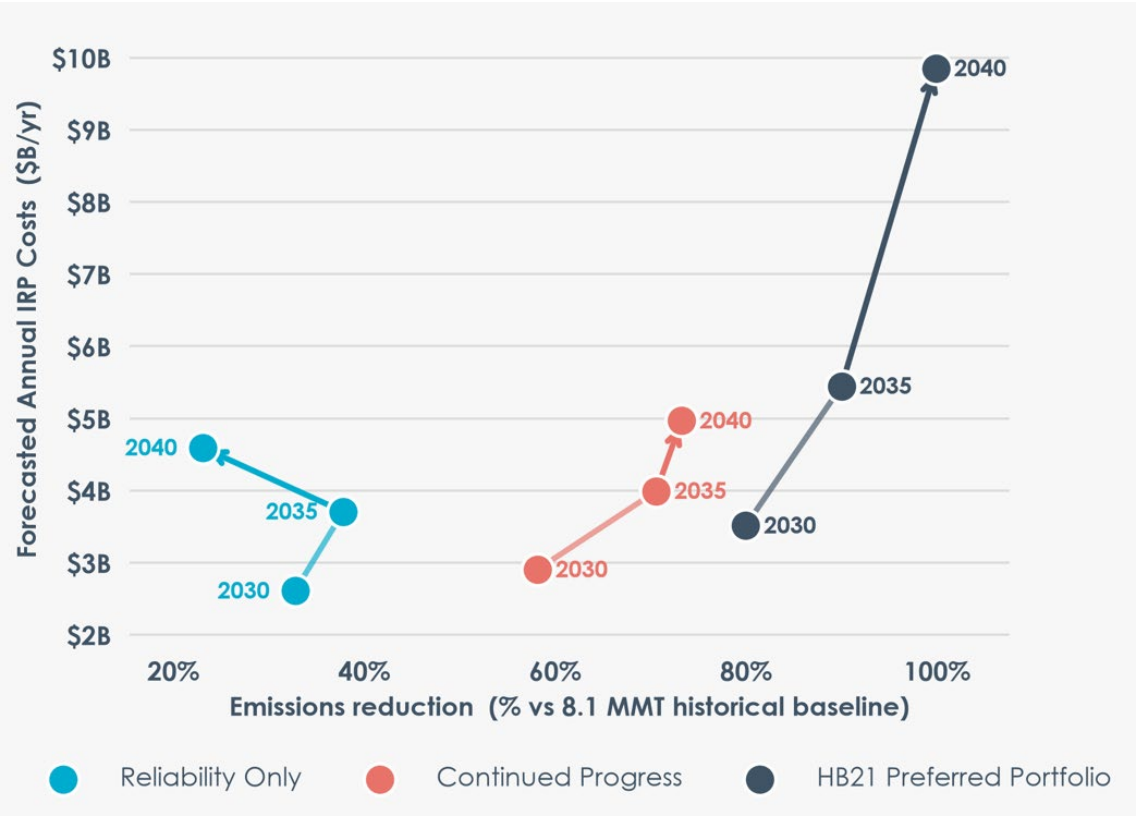
Figure 88 shows values for the HB 2021 Preferred Portfolio as well as the Continued Progress portfolio and Reliability Only portfolio.

Figure 88. HB 2021 Preferred Portfolio Annual IRP Cost v. Continued Progress and Reliability Only



For context, the HB 2021 Preferred Portfolio runs on average about $385 million per year above the Reliability Only portfolio for the first five years of the analysis (2027-2032), widening to about $5.2 billion in the last five years of the analysis (2041-2046), as shown in Figure 88. While 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.ge. administrative costs, wildfire costs, etc.), this finding suggests that the cost of procuring resources above and beyond those needed to reliably serve customers are significant. This emphasizes the importance of flexibility and the ability to balance decarbonization with reliability and affordability. Refer to Chapter 1 and Chapter 2 for additional discussion on this important dynamic and PGE's path forward.

Figure 89. Forecasted Annual IRP Costs Given Emission Reduction Performance



Comparison between the emissions outcomes and costs of these three (3) scenarios reveals a favorable cost-to-emissions-reduction tradeoff for the Continued Progress portfolio, which achieves substantially greater reduction in emissions relative to the Reliability Only portfolio, at lower cost compared to the costs of the GHG Glidepath portfolio. Figure 89 shows the forecasted IRP costs associated with emissions reductions of the three (3) regulatory structures, highlighting the significant cost increase needed to achieve full emissions reduction targets.

7.8 SSR Analysis

As required by ORS 469A.210, PGE has a 10% small-scale renewable (SSR) target, requiring that 10% of electrical generating capacity come from renewable resources smaller than 20 MW or qualifying biomass generators starting in 2030. As described in Appendix Section G.4, PGE analyzed the need for meeting this SSR requirement for select portfolios,[123] with and without contributions of net metered (NEM) renewables, i.e., distributed solar PV. Table 32 summarizes PGE's 2030 SSR compliance position for each scenario, with and without contributions of NEM. With all NEM solar considered as an eligible resource, there is a much smaller incremental need to meet the 2030 target in each scenario

[123] See 7.3 Scenarios Analyzed for more information on the scenarios.

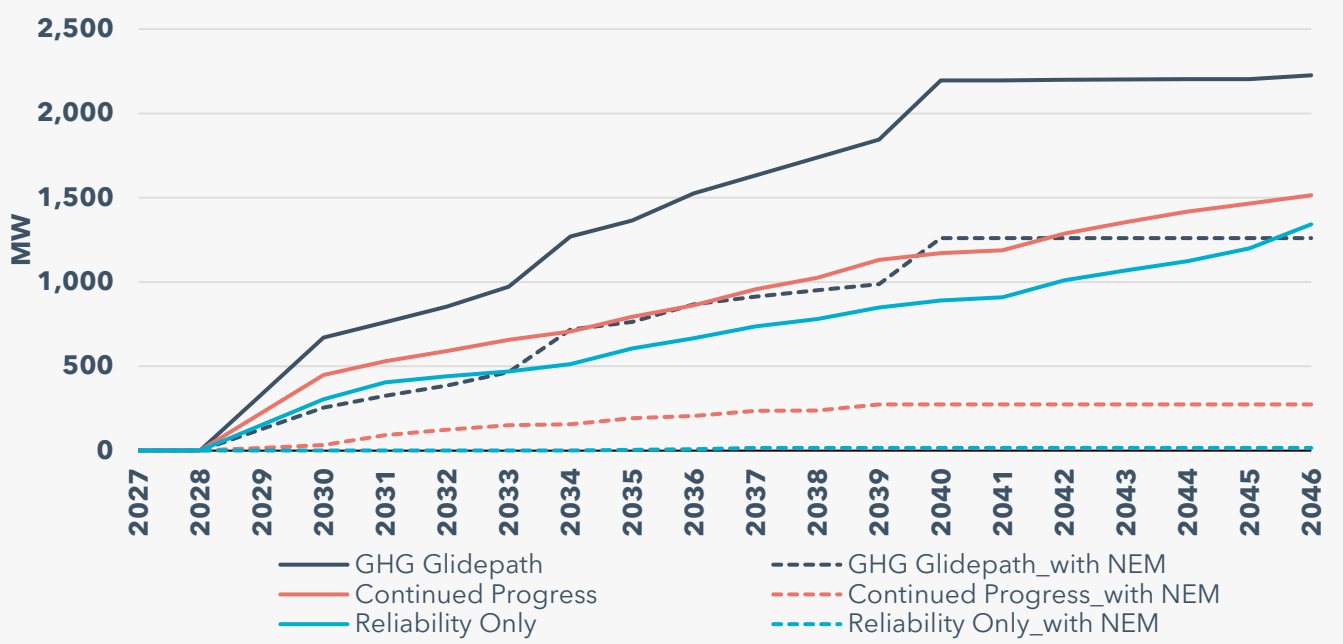
Table 32. SSR Compliance Position in 2030 for select scenarios

Compliance Position (MW)	GHG Glidepath		Continued Progress		Reliability Only	
	NEM Excluded	NEM Included	NEM Excluded	NEM Included	NEM Excluded	NEM Included
2030 Compliance Requirement[124]	1,066	1, 112	817	863	672	718
Existing Baseline Resource Contribution[125]	369	369	369	369	369	369
Proxy New Resource Contribution from Portfolio Analysis[126]	27	27	0	0	0	0
Forecasted Customer-Sited NEM Contribution[127]	N/A	461	N/A	461	N/A	461
Incremental Need for 2030 Compliance	670	255	448	33	304	-

As described in Appendix Section G.4, this SSR analysis focused on the incremental additional costs to build the necessary SSR resources to meet the targets beginning in 2030, and for each following year of the planning horizon. Due to economies of scale, these smaller resources were assumed to be 8% more expensive than the proxy Christmas Valley solar resource option,[128] resulting in an SSR premium of roughly $17-$20/kW-yr (2026$) for any increment of SSR capacity built, depending on COD. Figure 90 shows the cumulative SSR additions across the planning horizon necessary to meet the SSR target in 2030 and each year thereafter, for the three (3) key portfolios, with and without NEM as a qualifying SSR resource. As demonstrated above, SSR need is proportional to resource need adding additional cost implications for the GHG Glidepath regulatory structure.

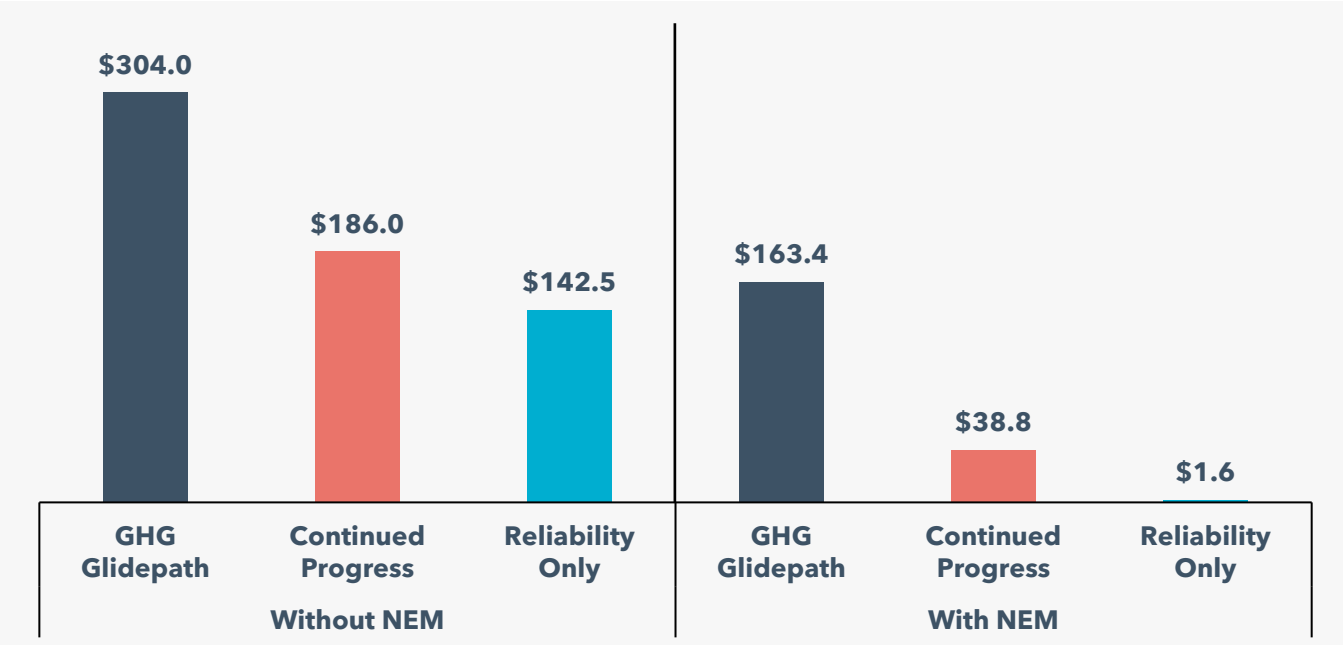
[124] In accordance with ORS 469A.210, battery storage capacity is not included in SSR analysis.
[125] PGE's current existing portfolio of resources and forward-looking assumptions for IRP are described in Appendix F.
[126] This includes the renewable resource portion of proxy CBREs selected by 2030 in portfolio analysis. No other proxy resource options in portfolio analysis are considered SSR eligible.
[127] Rooftop solar forecast is performed in AdopDER, and is part of PGE's load forecast, with results summarized in Section 6.2.2.3.
[128] See Appendix Section G.7 for fixed costs of proxy Christmas Valley (Central Oregon) solar resource.

Figure 90. Cumulative SSR Additions to Targets



The incremental cost premium to build these SSRs was applied to the incremental small-scale capacity needed each year, with the additional fixed cost assumed to incur in each year throughout the resource life, until the end of the planning horizon. The additional NPVRR to build the necessary small-scale capacity to meet the SSR targets for each scenario is reported in Figure 91.

Figure 91. NPVRR Additional Build Costs for SSR Compliance Across 20-year Planning Horizon ($Millions)



These costs do not represent full portfolio impacts nor operating costs, as building SSR capacity would offset other builds from portfolio analysis. However, these results do indicate the magnitude of additional cost premiums necessary to build SSRs for different scenarios.

7.8.1 SSR Acquisition Strategy

The above analysis provides indicative findings on the incremental cost of meeting the SSR requirement for select scenarios, over and above otherwise least-cost, least-risk analysis. Higher additional costs are anticipated as the PGE's generating portfolio becomes larger given the SSR requirement is a percent of installed capacity.

Under current OPUC eligibility criteria, net-metered and other behind-the-meter resources (NEM) do not count toward the SSR requirement, even though these resources can provide meaningful clean energy, flexibility, resilience, and system benefits. While PGE continues to see strategic value in deploying relatively costly distributed solar resources in a manner that best aligns with VPP growth and continuing customer and community interest in customer-sited and behind-the-meter resources, there is no current pathway for such resources to contribute to PGE's SSR compliance. Hence PGE's continuing actions to promote and maximize the value of customer-sited resources are distinct from the SSR strategy.

PGE will therefore pursue a portfolio of qualifying SSR resources, including Community-Based Renewable Energy projects, Community Solar, and other eligible small-scale resources, prioritizing projects that provide benefits beyond compliance. Because smaller projects can carry a significant cost premium relative to utility-scale resources, PGE will emphasize affordability, system value, community benefits, and opportunities to leverage grants, incentives, and other external funding to reduce customer costs. As described in Section 2.1.2, PGE intends to supplement these efforts with a dedicated SSR procurement action.

These approaches allow PGE to make progress toward the statutory obligation by pursuing SSR compliance as cost-competitively as possible under applicable rules.

7.9 rCBI Sensitivity Analysis

The 2026 CEP/IRP cycle advances PGE's resource Community Benefits Indicator (rCBI) framework by focusing solely on Community-Based Renewable Energy (CBRE) resources and incorporating insights from the CBRE Request for Offers (RFO), which found CBRE projects to be significantly more costly than comparable utility-scale alternatives. The development of the CBRE proxy resource and its costs are described in detail in Appendix Section G.3.

To evaluate how additional funding, monetized community benefits, or other cost-reducing mechanisms could improve CBRE competitiveness across portfolio analysis, PGE applied a rCBI-based cost adjustment to the proxy CBRE resource cost assumptions in all scenarios beginning in 2032. See Appendix Section D.3 for more detailed methodology. The inclusion of rCBIs reduced fixed costs of CBREs by roughly half, encouraging their selection in portfolio analysis.

To illustrate how these assumptions influence CBRE deployment and provide insight into the conditions under which CBREs would need to become more cost-competitive resource options

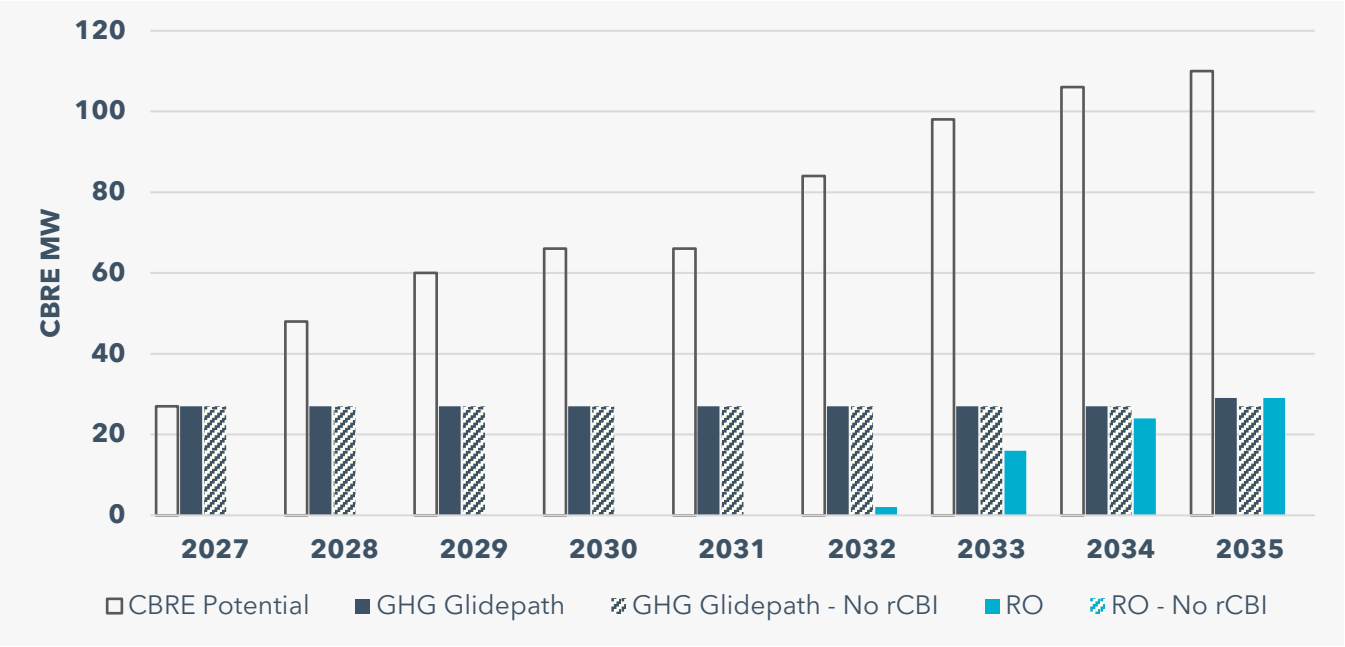
outside of planning, a sensitivity analysis was conducted in ROSE-E for the GHG glidepath and Reliability Only scenarios in which the rCBI cost reduction for CBREs was excluded to represent costs for the proxy CBRE resource in portfolio analysis more similar to the market data from CBRE RFO learnings. Comparing resource selection with and without rCBIs helps demonstrate the extent to which the assumed rCBI value influences the selection of CBRE resources in cost-optimized portfolio analysis.

Results of the sensitivity analysis are shown in Figure 92, where the quantity of CBREs selected are shown with rCBIs (from main portfolio analysis) and without rCBIs (from this sensitivity analysis).

In the Reliability Only scenario with rCBI value accounted for in the fixed costs of the CBRE resources beginning in 2032, 29 MW of CBREs are selected throughout the planning horizon. All of the selected CBREs are added between 2032 and 2035 and include the base rCBI value, which acts to encourage CBRE selection. By contrast, no CBRE resources are selected in the No rCBI sensitivity of the Reliability Only scenario, where the proxy CBRE resource retains its full cost premium.

In the GHG Glidepath scenario, with rCBI values included, 29 MWs of CBREs are added throughout the planning horizon. Out of this total, 27 MWs are added in 2027, when rCBIs are not part of the CBRE cost structure, and 2 MW of CBREs, with rCBIs included, are added in 2035. In the No rCBI sensitivity of the GHG Glidepath scenario, the total MW of CBREs selected is reduced to 27 MW as a result of the 2 MWs of rCBI-containing CBREs from the GHG Glidepath scenario no longer being selected.

Figure 92. Cumulative Selection of CBREs in rCBI Sensitivity Analysis



These results suggest that the presence of rCBIs in the base case assumptions are an important factor driving the selection of CBREs in portfolio analysis. The base case rCBI value encourages selection of some, but not all, of the available proxy CBRE potential, suggesting that the assumed rCBI reduction in costs improves the cost-competitiveness of CBREs relative to utility-scale

resources, but does not fully overcome the cost premium relative to other resources to maximize uptake. The results suggest that the inflection point of CBREs from being cost-competitive to not cost-competitive occurs at some point within the range of with and without rCBIs. This outcome indicates that the costs from the CBRE RFO bids remain a potential barrier to deployment of these kinds of CBRE projects, and that realization of community-benefit value, grant support, or other forms of cost reduction are likely necessary conditions for meaningful CBRE expansion. The selection of 27 MW of CBREs without rCBIs in the GHG Glidepath scenario highlights another dynamic in portfolio analysis where timing of need and resource availability can dominate resource economics in the determination of resource selection. In the near-term, the combination of higher needs in the GHG glidepath scenario and limited resources available for selection in the first years of the analysis, the selection of CBREs is robust regardless of presence or absence of rCBI values.

While these results focus on the resource selection impacts of rCBIs only, pCBIs and iCBIs offer additional methods of considering the benefits of CBREs (and other community-beneficial resources and actions) within this planning framework. While not a driver of resource selection in portfolio analysis, pCBIs offer another quantifiable metric of community benefits provisions and are an important component of portfolio scoring, as described in Section 7.5. From a look-back perspective, iCBIs provide an additional lens through which to view community benefits, as summarized in Chapter 1 and detailed in Appendix Section D.4.

7.10 VPP Results

PGE's VPP is broader than a single program or technology. It includes flexible load programs, customer-sited DERs, distributed storage, managed charging, dispatchable standby generation (DSG), and enabling technology platforms that allow resources to be forecasted, grouped, dispatched, measured, and evaluated over time. VPP is a coordinated portfolio designed to unlock customer and system flexibility before relying only on new infrastructure.

In this IRP, VPP Flex Load and DSG resources are being evaluated for the first time alongside other supply-side options as selectable resource options. Existing Flex Load measures, which are already part of PGE's VPP, future Flex Load measures that could potentially become part of the VPP and DSG are evaluated for their ability to contribute to system capacity needs, reduce peak demand, support reliability, and provide flexible operational value during periods of system need. In simple terms, a measure is a specific customer action, technology, or program that produces a measurable grid benefit. In the flexible load world, the programs are examples of different measures.

PGE's capacity expansion model, ROSE-E, selects a combination of resources that minimizes system costs across the planning horizon. As discussed earlier, portfolios have been used as the necessary diagnostic tool which assume potential future scenarios and inform the resultant resource composition. In the case of the VPP, the portfolios constructed based on the different set of assumptions within the planning scenarios inform the extent of DSG selection and the various flex load resource options within the five VPP bins summarized in Table 33. One of the main takeaways from the results of all the scenarios is that high volume of VPP resources (relative to what is available for selection in the model) gets elected by the capacity expansion model when it constructs least-cost least-risk portfolios.

Table 33. VPP DR Bins available for selection in Portfolio Analysis

Large MW Dispatchable PGE Programs	Non-Dispatchable PGE Programs	Other PGE Programs / Pilots	High Technical / Market Potential	Stretch / Emerging
Bin 1	Bin 2	Bin 3	Bin 4	Bin 5
Res. Smart T-Stats **EP – Schedule 26**	Peak Time Rebates Time of Day	Res. EV Charging Com. EV Charging EP – Schedule 25 MF Water Heaters Res/Non-Res Storage	EP – Cold Storage MF Ducted Heat Pump Connected Air-Source HP Connected Smart Electric Resistance Water Heater	EP – Agriculture Microgrids Fleet Charging (DCFC) Single Family Water Heating Other Potential DR

EP = Energy Parter; Res. = Residential; Com. = Commercial; MF = Multi-family; EV = electric vehicle; DCFC = direct current fast charging; HP = Heat Pump

Extensive analysis was performed to determine the impact of key variables and uncertainties on outcomes. The goal was to consider various uncertainties to create a roadmap for VPP growth that balances affordability, reliability, and decarbonization for PGE customers.

VPP Flex Load bins 1 and 2 are largely favored for least cost portfolio construction. These two bins include existing Flex Load programs. It is important to note that all of the capacity (in MW) of bin 1 estimated to be available each year in the planning horizon gets elected in multiple scenarios. The criticality of procuring bin 1 resource in winter is evident from the fact that 100% of the capacity forecasted to be available during winters over the years is elected for more than 75% of all the planning scenarios. High volumes of capacity forecasted to be available for bin 2 are elected specifically for scenarios which focus on GHG emissions reduction or preparing for uncertainties related to transmission system expansion. These existing programs are mature, relatively large-scale and cost-effective, and combining the results from the IRP analysis evidence that these resources are important for meeting capacity and energy needs of the system in an affordable manner.

Bin 3 includes other programs and pilots which are presently relatively smaller in scale. Due to the costs of the technology involved and the relatively lower scale of current deployment, the costs of this bin are comparatively higher than bins 1 and 2. Despite that factor, bin 3 resources are elected for meeting needs specifically in summer in majority of the scenarios. Relatively smaller volumes of bins 4 and 5 are elected in multiple scenarios. It is important to remember that the cost estimates for bins 4 and 5 are high, relative to the other bins for multiple reasons related to scale, technology cost, and maturity of these measures. Due to the relative immaturity of these measures, PGE's confidence on the cost trajectory of these binds is limited. However, as the technology matures and the adoption of relevant devices/equipment grows over time, the cost of some of these measures are expected to drop. In the future, PGE will enhance the cost estimates for bins 4 and 5 over the planning horizon.

Table 34. Average Event Capacity (MW) of VPP DR by Bin and Season

Bin	PGE Program / Pilot	Primary Value	Season	2030 Potential (incremental)
Bin 1	Yes	Fully dispatchable capacity Established programs structure/participation	Summer	20.0
			Winter	11.5
Bin 2	Yes	Participant-driven load shifting providing broad peak reduction, but not dispatchable	Summer	16.8
			Winter	5.9
Bin 3	Yes	DR pilots with measurable but smaller capacity contribution by program	Summer	5.6
			Winter	2.8
Bin 4	No	Emerging, high-potential DR expected to become cost-effective and dispatchable with future program development	Summer	11.5
			Winter	11.7
Bin 5	No	Higher-cost DR resources capable of providing dispatchable capacity but requiring significant incentives or program funding	Summer	10.4
			Winter	17.5

The total VPP resource additions in GHG Glidepath, Continued Progress, and Reliability Only scenarios by years 2030, 2035, 2040 and 2045 are in Figure 93, Figure 94, Figure 95, and Figure 96. Comparison of these results shows that all three (3) scenarios select all available capacity for the DSG resource. The Reliability Only scenario selects the highest volume of VPP Flex Load among the three (3) with 2-3 times volume of VPP Flex Load selected for winter over the planning years compared to the other scenarios. For all of these principal scenarios more than 94% of the total capacity of VPP Flex Load and DSG resources that are selected in the planning horizon are added by 2030. VPP resources are one of the critical resources that are available in the early years since procurement, installation and operationalizing bulk generation and transmission resources can often have a long lead time.

Figure 93. VPP Resource Selection in GHG Glidepath (Reference Portfolio)

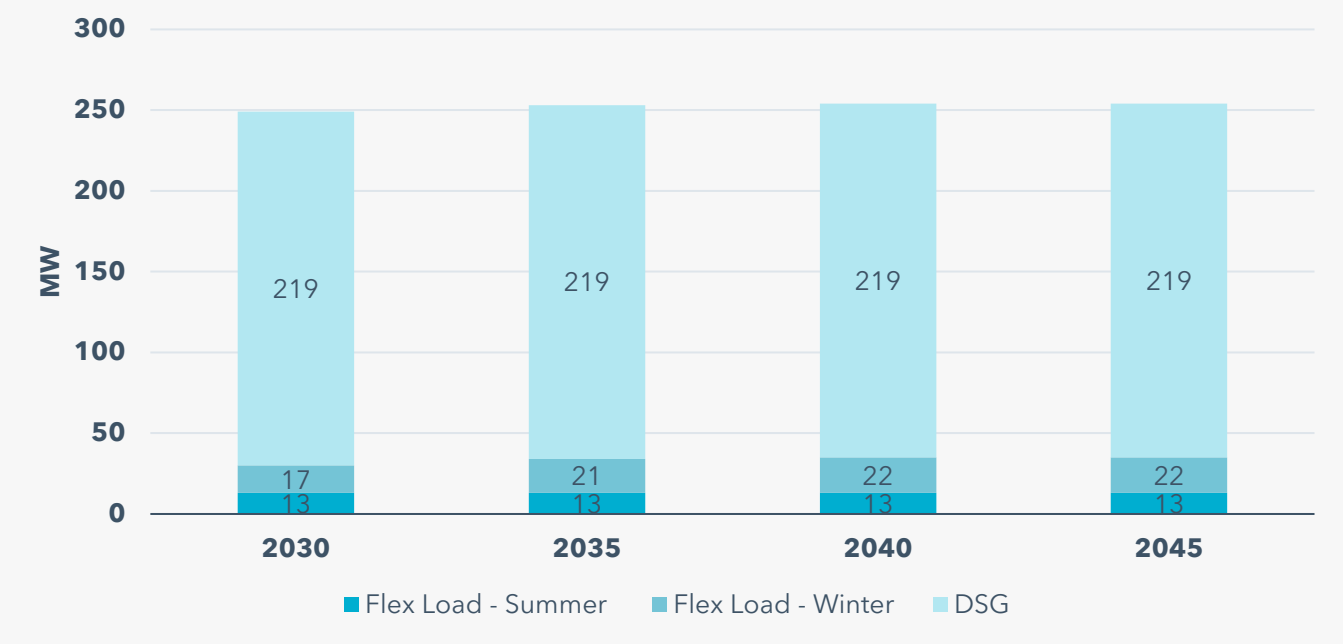


Figure 94. VPP Resource Selection in Reliability Only (Reference Portfolio)

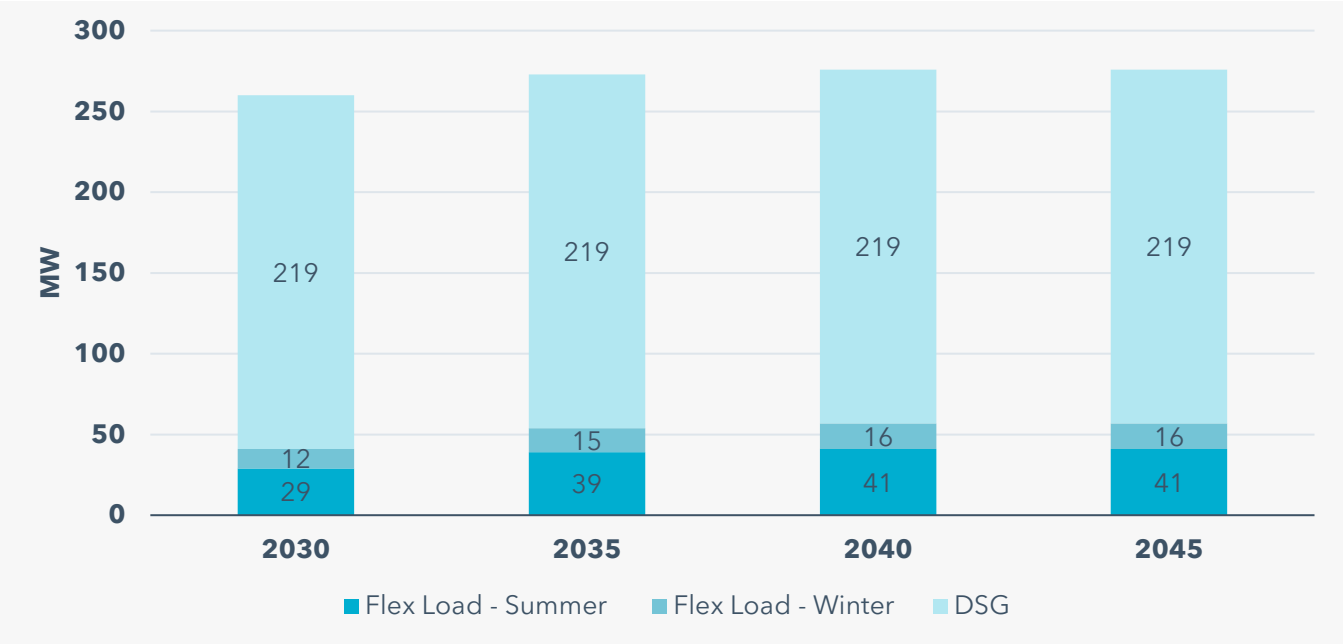
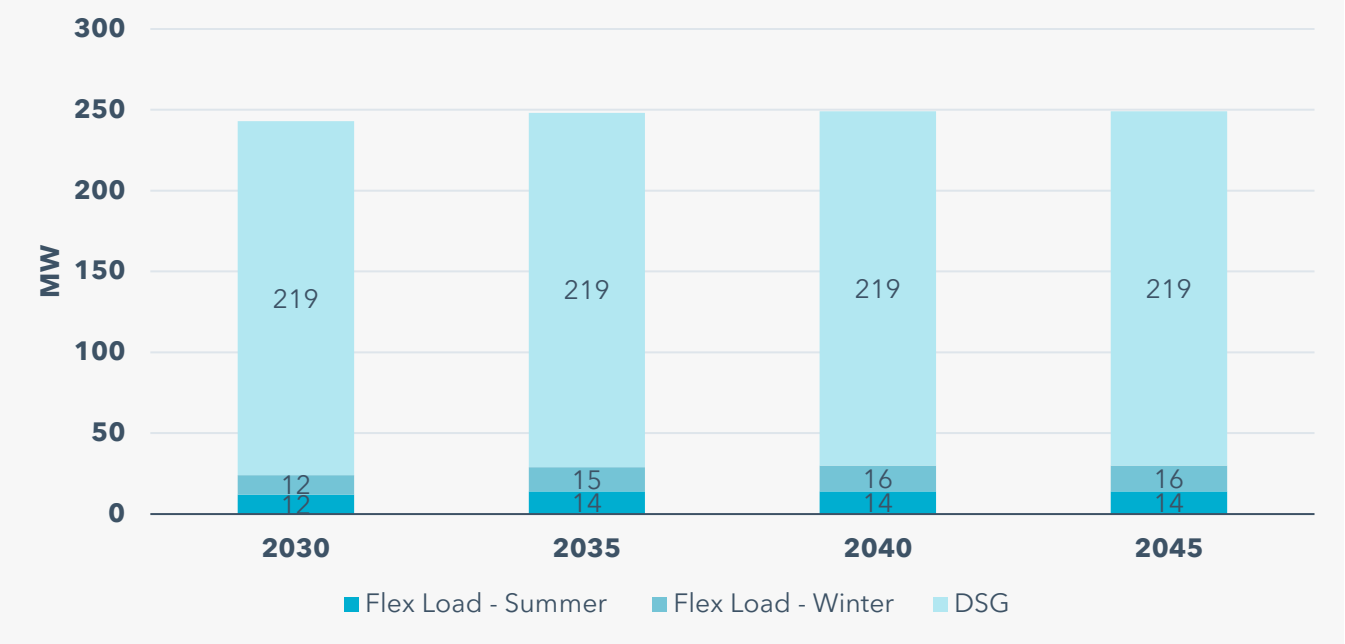
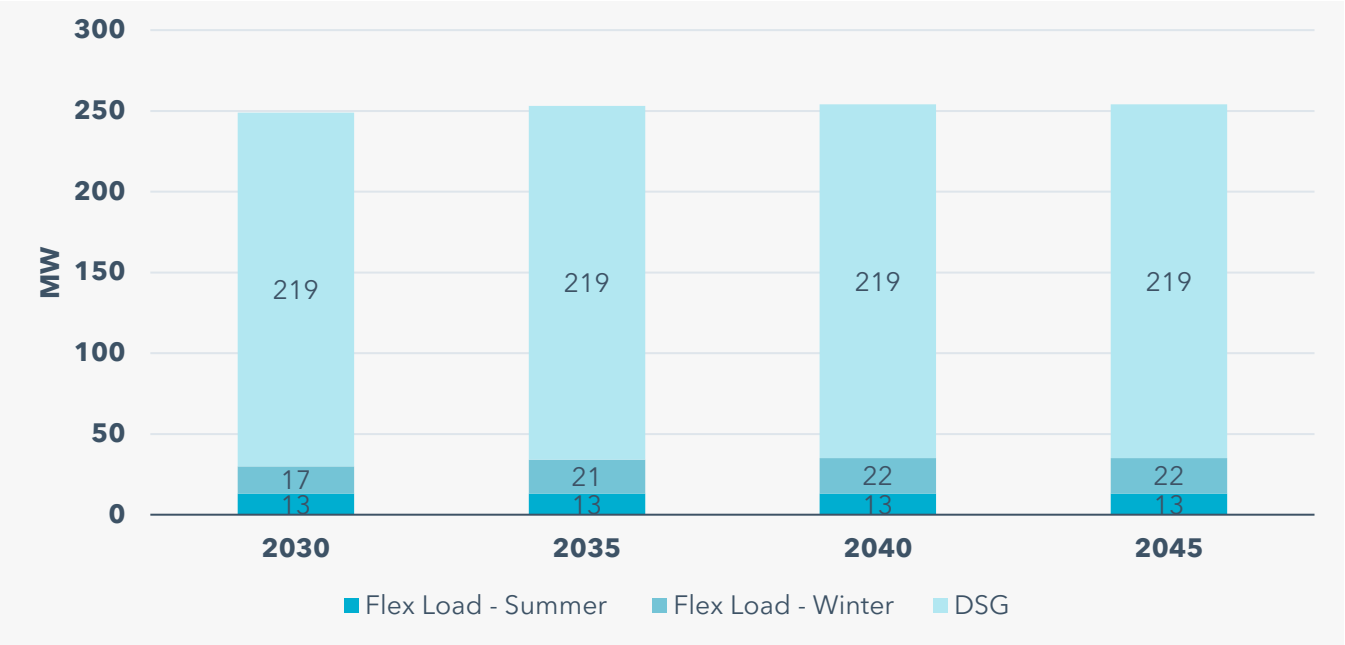


Figure 95. VPP Resource Selection in Continued Progress (Reference Portfolio)



The HB 2021 Preferred Portfolio shows similar VPP Flex Load and DSG capacity addition over the planning period as the GHG Glidepath scenario. 100% of available capacity in MW under bins 1, 2, 3 and 5 are selected for summer and bins 1 and 2 are selected for winter season in 2027. Throughout all years in the planning period the portfolio selects 100% of available capacity in MW for bins 1 and 2 in winter. This underscores the importance of existing programs in meeting both current and long-term capacity and energy needs in an affordable and reliable manner.

Figure 96. VPP Resource Selection in HB 2021 Preferred Portfolio



VPP also provides benefits that extend beyond capacity accreditation. Flexible customer resources can help reduce exposure to high-cost market purchases, improve use of existing infrastructure, support transmission and distribution constraint management, and create a pathway for increased customer participation in grid operations. As PGE's customer and grid platforms mature, the VPP is expected to provide more targeted and operationally useful value, including locational dispatch, market integration, and improved coordination with distribution planning.

PGE recognizes that this is the first iteration towards modeling VPP resources within the IRP, and this process will continue to evolve in future iterations. Future planning cycles are expected to improve the granularity of VPP assumptions, including program-level costs, adoption forecasts, dispatch availability, hourly load impacts, ELCC values, locational benefits, and performance under different system conditions. This iterative approach is consistent with the VPP Multi-Year Plan and supports transparent evaluation of VPP resources as part of PGE's least-cost, least-risk planning framework.

7.11 Portfolio Reliability

Portfolios are designed to meet reliability requirements in accordance with OAR 860-090-0060 (7)(e). Two (2) methods are used to validate the reliability of portfolios constructed in PGE's capacity expansion model ROSE-E. The first is to validate that capacity needs are met by the resource buildouts elected in ROSE-E. Second, resource buildouts for select portfolios and years are input into PGE's resource adequacy model, Sequoia, to test their adequacy in an hourly simulation inclusive of resource interactions. The following section describes the results from these two (2) validations, suggesting that portfolios defined by ROSE-E are meeting capacity need requirements and hourly simulations indicate portfolios are resource adequate within the Action Plan window.

7.11.1 Reliability Position in ROSE-E

PGE evaluated the reliability of key portfolios by calculating the capacity position of each portfolio during all years of the planning period. The capacity position is defined as the seasonal capacity need (See Section 6.6.1.2) minus the sum of seasonal accredited capacity.[129] Below, Figure 97, shows the seasonal reliability of the GHG portfolio reference resource buildout across the planning horizon.[130] This figure shows capacity need is less than or equal to zero for all years of the planning horizon, indicating the capacity contribution of the resource buildout fills the system capacity need. This figure also indicates that Winter is the most difficult season to meet reliability, where for all but the first three-years of the horizon the resource buildout results in a capacity position that is shorter in winter than in summer.

[129] Accredited Capacity is calculated by ROSE-E at run-time using the ELCC curves defined for the analysis.
[130] Accredited Capacity as measure prior to post model MW additions used to meet GHG glidepath targets at hourly granularity.

Figure 97. Reliability in ROSE-E: GHG Portfolio

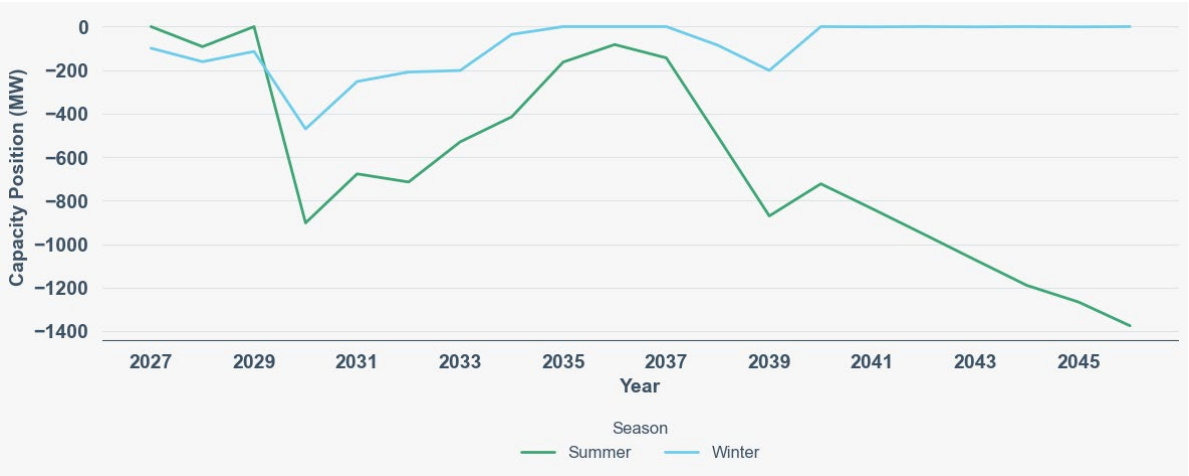
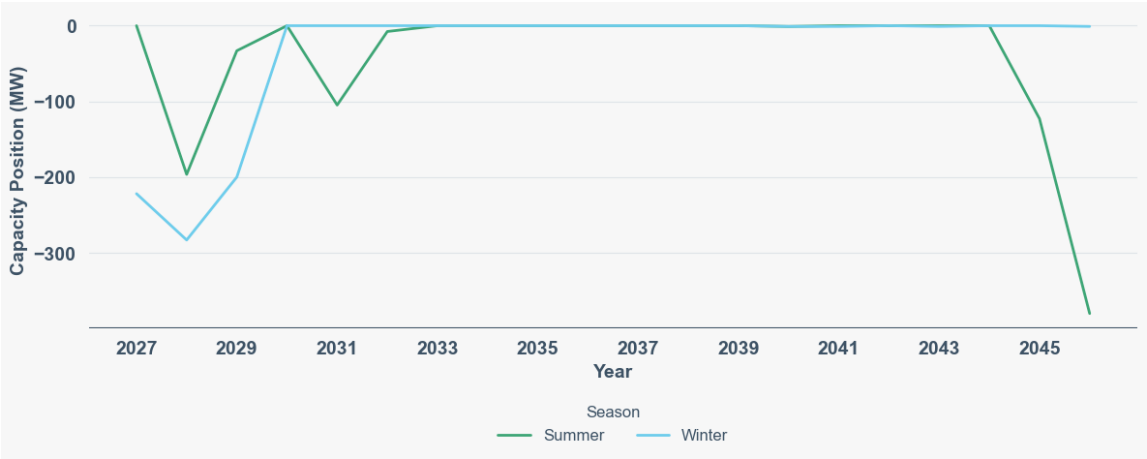


Figure 98 and Figure 99 show the capacity position for the Continued Progress and Reliability Only reference resource buildouts. Both figures show similar conclusions. First, resource buildouts are meeting capacity needs, and second, Winter is the constraining season.

Figure 98. Reliability in ROSE-E: Continued Progress Portfolio – Reference Resource Buildout

Figure 99. Reliability in ROSE-E: Reliability Only Portfolio–Reference Resource Buildout



Comparing the three (3) figures above it is also clear there are many years when resource buildouts provide more capacity than required to meet reliability needs in both seasons. In the Reliability Only portfolio, this length is limited to the first three (3) years of the planning horizon where the buildout is comprised of either natural gas contracts or VPP resources. As these VPP resources are not available later in the planning horizon, the model elects to procure VPP resources in the short term to meet needs in later years at the lowest cost. This propensity to overbuild capacity resources with respect to reliability needs is more apparent in the GHG and Continued Progress Portfolios. As the buildout grows from the Continued Progress Portfolio to the GHG portfolio there are a greater number of years that exceed the reliability standard as reliability is no longer the driving constraint for the resource buildout.

7.11.2 Reliability Position in Sequoia

The section above showed PGE's capacity expansion model constructs portfolios that meet the reliability standard represented by capacity needs. However, comments were raised in PGE's 2023 CEP/IRP questioning the reliability of portfolios constructed in ROSE-E when simulated in an hourly resource adequacy model.[131] This section confirms portfolios are reliable within the Action Plan window when tested in PGE's hourly resource adequacy model, Sequoia.

ELCCs are intrinsically a function of the interactive effects within a portfolio of resources and their relationship to load. The ELCC of a marginal resource addition in one portfolio is not necessarily equal to the same resource addition in a portfolio with different resources or load shape due to the complementary and antagonistic relationships captured in a loss of load study.[132] Antagonistic interactive effects have the potential to obscure the reliability of a portfolio of resources that meets capacity needs as resource generation profiles overlap and the benefit of the whole is less than the sum of its parts. Three (3) key reference case portfolios were tested in four years of the planning horizon to measure reliability inclusive of interactive effects. Results from these loss-of-load studies

[131] LC 80 Round One Comments of AWEC at 7-8
[132] Energy and Environmental Economics. 2025, Resource Adequacy for the Energy Transition: A Critical Periods Reliability Framework and its Applications in Planning and Markets. p15

in Table 35 shows all three (3) portfolios are resource adequate within the Action Plan window.[133] The results support that resource accreditation abstractions used in the capacity expansion model provide a reasonable approximation of capacity contributions in the IRP modeling exercise. Results in years 2035 and 2040 indicate antagonistic interactive effects are present in all portfolios, increasing with greater resource penetration across both the planning horizon and portfolios. For example, Figure 99 shows the seasonal capacity position meets capacity needs in the year 2035 for the Reliability Only portfolio. In contrast, Table 35 shows a remaining capacity need of 227 MW in summer 2035. As the buildout in 2035 has like resources in standalone and hybrid variants from the same or similar geographic reasons it is likely that correlated solar generation and wind generation reduce the net benefit of the portfolio.

Table 35. Portfolio Remaining Capacity Need – Hourly Loss of Load Study

	GHG		Reliability Only		Continued Progress	
Year	Summer	Winter	Summer	Winter	Summer	Winter
2030	0	0	0	0	0	0
2032	0	0	0	0	0	0
2035	0	56	227	0	30	97
2040	246	429	284	64	202	64

Table 76 expands on the above analysis displaying measures of seasonal Loss-of-Load-Expectation (LOLE) for the same years.[134] Given PGE's interpretation of the one-event-day-in-10-years reliability standard (see Appendix Section H.5.10), values are presented as the reciprocal of expected count of event days per year (LOLD), interpreted as "one event every X years."[135]

Table 36. Seasonal Loss of Load Expectation – Estimated Event Frequency (Years)

	GHG		Reliability Only		Continued Progress	
Year	Summer	Winter	Summer	Winter	Summer	Winter
2030	-	-	10	10	-	250
2032	-	53	11	13	-	45
2035	20	6	2	67	8	5
2040	1	0	1	6	4	6

[133] Resource buildout as measured prior to post model MW additions used to meet GHG glidepath targets at hourly granularity.
[134] Defined by the Electric Power Research Institute as "expected count of event-periods per study horizon, with an "event-period" defined as a period of time during which system resources are insufficient to meet demand."
[135] As discussed in LC 80, Round 1 Comments: PGE Response, seasonal capacity needs are derived from separate summer and winter reliability assessments. Consequently, the two seasonal standards are not cumulative and should not be interpreted as permitting 2 event-days-in-10-years.

Results from Table 36 highlight two (2) notable trends. First, the excess adequacy measured in the Reliability Only portfolio in year 2032 suggests complementary effects in the resource portfolio are present in addition to antagonistic interactions discussed above. Second, there are diminishing marginal returns to reliability through increased resource buildout. Comparing winter estimated event frequency for the three (3) portfolios in the year 2032, the continued progress portfolio measures 3.5 times the reliability as the Reliability Only resource buildout while the GHG buildout measures only four (4) times the reliability. These results indicate the additional 1,804 MW of cumulative new resource buildout in the Continued Progress portfolio contribute meaningfully to a more reliable system, while the additional 2,949 MW of additional buildout required in the GHG portfolio provides a quarter of the reliability benefit of those resources added in the Continued Progress buildout. Observing a diminishing reliability benefit is significant as the resource planning process aims to balance affordability and decarbonization in a future portfolio and also reiterates findings from regional adequacy studies which emphasize the reliability role of firm dispatchable resources.[136]

[136] See Chapter 3 and Section 1.3.3.

8 Appendix

Appendix A Acronyms

A.1 Acronyms and Abbreviations

Table 37. Acronyms and Abbreviations

Acronym / term	Definition
AC	Alternating Current
ACP	Alternative Compliance Payment(s)
AFDC	Alternative Fuels Datacenter
ATC	Available Transfer Capability
AUT	Annual Update Tariff / Annual Power Cost Update Tariff
BAA	Balancing Authority Area
BESS	Battery Energy Storage System
BPA	Bonneville Power Administration
BRIC	Building Resilient Infrastructure and Communities
CAISO	California Independent System Operator
CBI	Community Benefit Indicator
CBIAG	Community Benefits and Impacts Advisory Group
CBRE	Community-Based Renewable Energy
CE EE	Cost-Effective Energy Efficiency
CEAE	Canadian Entitlement Allocation Extension
CEP	Clean Energy Plan
CESER	Cybersecurity, Energy Security, and Emergency Response
CFS	Conditional Firm Service
CGO	Core Growth Only
CMC	Competitive Market Choice
CO2e	Carbon Dioxide Equivalent
COD	Commercial Operation Date
CTWS	Confederated Tribes of Warm Springs
DER	Distributed Energy Resource
DERMS	Distributed Energy Resource Management System
DMS	Distribution Management System
DOE	U.S. Department of Energy
DSG	Dispatchable Standby Generation
DSO	Distribution System Operator

Acronym / term	Definition
DSP	Distribution System Plan
EDAM	Extended Day-Ahead Market
EE	Energy Efficiency
EFSC	Energy Facility Siting Council
EIM	Energy Imbalance Market
ELCC	Effective Load Carrying Capability
ESS	Electricity Service Supplier
ETO	Energy Trust of Oregon
EV	Electric Vehicle
EVSE	Electric Vehicle Supply Equipment
FAA	Federal Aviation Administration
FEOC	Foreign Entity of Concern
FERC	Federal Energy Regulatory Commission
GEC	Grid Edge Computing
GETs	Grid Enhancing Technologies
GHG	Greenhouse Gas
GID	Grant Identification; PGE internal numbering system
GRC	General Rate Case
GRIP	Grid Resilience and Innovation Partnerships
GWh	Gigawatt-hour
HB 2021	Oregon House Bill 2021, Clean Energy for All legislation
HFRZ	High Fire Risk Zone
HRCO	Heat Rate Call Option
HVDC	High Voltage Direct Current
IBR	Inverter-Based Resource(s)
IQBD	Income Qualified Bill Discount
IRP	Integrated Resource Plan
ITC	Investment Tax Credit
LOLD	Loss of Load Day(s)
LOLE	Loss of Load Expectation
LTDA	Long-Term Direct Access
LTF	Long-Term Firm Transmission Service
MAD	Measure Approval Document
MDS	Multi-Day Storage
MISO	Midcontinent Independent System Operator

Acronym / term	Definition
MW	Megawatt
MWa	Average Megawatt
MWh	Megawatt-hour
NCE EE	Non-Cost-Effective Energy Efficiency
NEM	Net Energy Metering
NEPA	National Environmental Policy Act
NITS	Network Integration Transmission Service
NOPE	North of Pearl Flowgate
NPC	North Plains Connector
NPVRR	Net Present Value Revenue Requirement
NWACI	Northwest AC Intertie
OATT	Open Access Transmission Tariff
OBBBA	One Big Beautiful Bill Act
ODEQ	Oregon Department of Environmental Quality
ODOE	Oregon Department of Energy
OPUC	Oregon Public Utility Commission
ORS	Oregon Revised Statutes
OSI	Open Systems International
PCAM	Power Cost Adjustment Mechanism
PCEF	Portland Clean Energy Fund
PGE	Portland General Electric
PGEM	PGE Merchant Function
PGET	Portland General Electric Transmission
PNW	Pacific Northwest
PPA	Power Purchase Agreement
PSPS	Public Safety Power Shutoff
PTC	Production Tax Credit
PTP + SCD	Point-to-Point Scheduling, System Control and Dispatch
QCC	Qualifying Capacity Contribution
QF	Qualifying Facility
RA	Resource Adequacy
RAAC	Resource Acquisition Adjustment Clause
RAC	Renewable Adjustment Clause
RBSA	Residential Building Stock Assessment
REC	Renewable Energy Certificate

Acronym / term	Definition
RFO	Request for Offer
RFP	Request for Proposal
RO	Reliability Only Portfolio
ROW	Right-of-Way
RPIP	Renewable Portfolio Standard Implementation Plan
RPS	Renewable Portfolio Standard
S-N	South-to-North, power-flow direction
Sensor-MAP	Sensor Placement, Monitoring, and Data Analytics Platform
SPP	Southwest Power Pool
SSR	Small-Scale Renewables
TH	Harborton-Trojan Transmission Project
TRC	Total Resource Cost test
TSR	Transmission Service Request
UM 2377	OPUC Docket UM 2377
USAP	Utility-Specific Action Plan
USECapacity	Unserved Energy attributable to resource inadequacy rather than flexibility inadequacy
USEFlex	Unserved Energy due to flexibility shortages
USFS	U.S. Forest Service
VER	Variable Energy Resource
VMT	Vehicle Miles Traveled
VPP	Virtual Power Plant
WECC	Western Electricity Coordinating Council
WRAP BPM	Western Resource Adequacy Program Business Practice Manual

A.2 Models, Programs, Studies, and Initiatives

Named analytical tools, market platforms, research organizations, programs, studies, and initiatives are separated from conventional acronyms for easier navigation.

Table 38. Models, Programs, Studies, and Initiatives

Model / program	Definition
AdopDER	PGE Distributed Energy Resource Adoption Model; a locational forecasting methodology combining top-down system assumptions with bottom-up, site-level adoption and load-growth modeling.
ARIA	Advanced Risk Integrated Analysis.
Aurora	Commercially available production cost simulation model used to evaluate supply, demand, transmission, market pricing, and resource performance.
Calpine	Capacity line contract/resource used in planning studies.
CARLA	Collaborations Advancing Rapid Load Additions.
COFFEE	Carbon Optimization Framework for Energy Emissions.
ConnectWerx	Agentic AI for Automated Interconnections project.
CREP	Community Renewal Energy Grant Program.
CREST	Climate Resilient Employees for a Sustainable Tomorrow.
Flexibility Study	Sylvan Energy Analytics study evaluating flexibility adequacy, flexibility value, and integration costs.
GAT	Grid Access Transformation.
GERP	Grid Expansion and Reinforcement Portfolio.
Grid Atlas	Publicly available catalog of realistic, geographically relevant representative distribution feeder models without sensitive geographic information, customer data, or disclosure of utility models.
Grid Copilot	Physics-informed artificial intelligence-based digital twin of the grid for real-time and predictive monitoring, situational-awareness analytics, recommendations, automated grid-control solutions, data validation, simulation training, and developer and community engagement.
GridPath	Open-source, modular power-system-planning platform used for production-cost simulation, capacity-expansion, asset-valuation, and resource-adequacy modeling.
JFF	Jobs for the Future.
LUCAS	PGE resource cost estimation model.
Markets+	Southwest Power Pool day-ahead market platform.
NEEA	Northwest Energy Efficiency Alliance.
NLR	National Lab of the Rockies.
OCEWC	Oregon Clean Energy Workforce Coalition.
OPTIMA	Operation and Planning Tools for Inverter-Based Resource Management and Availability for Future Power Systems.
ORNL	Oak Ridge National Laboratory.

Model / program	Definition
PACT	Permitting Alignment and Coordination Task Force.
PROTECT	Proactive Human-Machine Teaming Enabled Cybersecure Technologies.
PSU	Portland State University.
PZM	Portfolio Zone Model.
ROSE-E	Resource Optimization Scenario Engine used for resource portfolio and capacity-expansion analysis.
SALMON	SmartGrid Advanced Load Management & Optimized Neighborhood.
Sensor-MAP	Sensor Placement, Monitoring, and Data Analytics Platform for distribution-grid observability, sensor selection and placement, state estimation, and situational-awareness dashboards.
SETO	Solar Energy Technologies Office.
SSPC	Salem Smart Power Center.
STRIVES	Solar Technologies' Rapid Integration and Validation for Energy Systems
UCF	University of Central Florida.
UNR	University of Nevada, Reno.
WECC Model	Regional power-market model whose assumptions are incorporated into Aurora for simulation and forecasting.
WestTEC	Western Transmission Expansion Coalition.
WRAP	Western Resource Adequacy Program.

Appendix B Compliance Summary

Since PGE's last IRP, the OPUC adopted new administrative rules for IRPs and CEPs in Division 90 of the OPUC OARs. PGE's compliance with these rules is listed in Table 39. The OPUC also directed specific actions for the 2026 CEP/IRP via the acknowledgment order for the 2023 CEP/IRP. PGE's compliance with applicable requirements from Order No. 24-096 are listed in Table 40. PGE's 2023 IRP Update (published in 2025) provided a more thorough compliance summary on all Order 24-096 OPUC direction. Items for which compliance was completed, and no further updates are necessary are not reproduced in Table 40.

Table 39. Compliance with OPUC Administrative Rules Division 90

Rule	Requirement	PGE Compliance
860-090-0030(1)	Each energy utility must file an IRP with the Commission no later than three (3) years after the filing date of its prior IRP.	PGE's filing date of Oct 15., 2026, was approved in OPUC Order No. 26-356 on Sep. 28, 2026.
860-090-0030(2)	In preparing the IRP, the utility must allow opportunities for engagement that are open to all members of the public. Such opportunities must include opportunities to contribute information and ideas, receive information, and pose questions to the utility including but not limited to requests to run portfolios, futures, scenarios, etc. These opportunities for engagement must include opportunities that are accessible to members of the public with limited resources.	Appendix C and Appendix C.2 describe engagement approaches and opportunities.
860-090-0030(3)	The utility must include in its IRP filing a certification that it has concurrently submitted its responses to the most recent version of the Standard Information Requests for Integrated Resource Plans and Updates, available on the Commission's website.	PGE is concurrently submitting its Standard Information Request (SIR) responses via OPUC's Huddle system. In the absence of a final Staff template, PGE has provided information that aligns with the draft SIRs filed to Docket No. UM 2348 on May 1, 2026.
860-090-0030(4)	Except as otherwise directed by the Commission, the utility must publish information submitted pursuant to section (3) of this rule as indicated in the most recent version of the Standard Information Requests. Information exempt from disclosure pursuant to a protective order issued by the Commission may be provided in redacted form. The utility must keep the published information available to the public until the utility has filed two (2) subsequent IRPs.	As stated above, PGE will submit draft SIR responses to OPUC along with the 2026 CEP/IRP. PGE will continue to work with OPUC on finalizing SIR details and template and will provide public access to SIRs via PGE's IRP website once finalized.
860-090-0060(1)	Each energy utility must prepare an integrated resource plan that contains the information described in this rule.	PGE's IRP includes the information described in OAR 860-090-0060.

Rule	Requirement	PGE Compliance
860-090-0060(2)	Executive summary. The utility must include in the IRP a brief executive summary, written for a general audience, that describes the utility's long-term resource strategy and near-term action plan and explains any significant changes in the utility's strategy since the last IRP.	Executive Summary includes an overview of PGE's strategy, actions and strategy developments since the 2023 IRP written for a general audience.
860-090-0060(3)	Updates since last IRP. The utility must describe in the IRP the resource actions and actions toward enabling strategies the utility has taken since the last IRP.	Section 1.2 describes PGE's actions since the 2023 CEP/IRP.
860-090-0060(4)	Documentation of public input. The utility must include in the IRP an appendix that:	-
860-090-0060(4)(a)	Describes the opportunities the utility created for public input, which must include meetings that are open to all process participants, including the timeframes over which the utility accepted input from the public on each draft element of the IRP enumerated in OAR 860-090-0070.	Appendix C and Appendix Section C.2 describe opportunities for public input, major themes of input received, and discussion of how PGE considered incorporation of input and direction.
860-090-0060(4)(b)	Summarizes at a high level major themes of public input the utility received during the development of the plan using the mechanisms created by the utility and attaches all written public comments received in response to comment opportunities specified by the utility on each draft element of the IRP enumerated in OAR 860-090-0070;	Appendix D references above. PGE has posted written feedback received through the online feedback form, IRP email inbox, or other email communications to the IRP roundtable series website at https://portlandgeneral.com/about/who-we-are/resource-planning/combined-cep-and-irp/combined-cep-irp-public-meetings https://portlandgeneral.com/about/who-we-are/resource-planning/combined-cep-and-irp/combined-cep-irp-public-meetings.
860-090-0060(4)(c)	Documents whether and how the utility incorporated public input received during the development of the plan using the mechanisms created by the utility into the finalization of portfolios, planning scenarios, community impacts metrics, the action plan, the utility's response to any specific direction from the Commission, and other analysis or components of the IRP; and	PGE has posted responses describing if and how feedback was incorporated into final IRP work products to the IRP roundtable website referenced above.
860-090-0060(4)(d)	Documents how and when the utility explained any decisions not to incorporate public input received during the development of the plan using the mechanisms created by the utility into the IRP that is filed with the Commission.	PGE has posted responses explaining PGE's decisions not to incorporate feedback into final IRP work products to the IRP roundtable website referenced above.

Rule	Requirement	PGE Compliance
860-090-0060(5)	Commission direction. The utility must include in the IRP a narrative explanation and reference to the appropriate IRP section and, if applicable, subsection for the utility's response to any specific direction from the Commission to undertake or provide additional information, analyses or actions in the IRP since the filing of its prior IRP.	Table 40 in this appendix lists PGE's compliance with specific direction previously received from the Commission.
860-090-0060(6)	Needs assessment. The utility must include in the IRP an evaluation of the resource needs to achieve an acceptable level of reliability, including meeting any reliability requirements to which the utility is subject, while complying with all state and federal energy policies, over the next five years and in key planning years. The utility must describe in the IRP how the reliability analysis in the needs assessment accounts for opportunities presented by interactions with other systems and markets.	Section 6.6.1 discusses PGE's needs to ensure portfolios meet energy, capacity, RPS, and flexibility needs, with methodologies further detailed in Appendices. Appendix Section H.5.4 specifically addresses market interactivity assumptions for reliability analysis.
860-090-0060(6)(a)	The utility must calculate resource needs based on the utility's load forecast, which must be the most recent available at the time that the needs assessment calculation is performed, and no incremental actions beyond the commitments that the utility has entered into at the time of conducting the analysis.	Section 6.1 presents data from PGE's May 2026 load forecast portfolio described in Appendix F reflects resources with executed agreements as of May 2026.
860-090-0060(6)(b)	The utility must include in the assessment reasonable upper and lower bounds on resource needs based on key planning uncertainties.	Section 6.1, Section 6.6 and Section 7.3 describe modeling approaches to planning uncertainties.
860-090-0060(6)(c)	The utility must clearly define the metrics and units used to summarize identified resource needs and report the date on which assumptions were last updated to inform the needs assessment.	Section 6.6.1 defines metrics and units to assess needs, with further detail in Appendix H. Section 6.1 provides load forecast vintage details.
860-090-0060(7)(a)	Portfolio analysis. In developing the IRP, the utility must analyze a set of meaningfully different portfolios of resource options. The utility must provide in the IRP a detailed description of the analysis performed and the results of its analysis.	Section 7.2 presents PGE's approach to portfolio analysis, with detailed descriptions and results throughout Chapter 7.

Rule	Requirement	PGE Compliance
860-090-0060(7)(a)(A)	The utility must evaluate portfolios that test different levels of demand side resources and distributed resources in Oregon.	Section 6.1.3 describes Low, Reference and High solar and electrification inputs. Appendix G.2 describes the new proxy demand response options available in portfolio analysis that may be selected depending on costs and needs and conditions of a given scenario.
860-090-0060(7)(a)(B)	The utility must consider both commercially available and emerging technologies as resource options. For resources reliant on emerging fuels, the cost and availability of fuel supply, transport, and storage, as appropriate, must be considered.	Appendix G lists resource options considered in PGE's modeling, including emerging technologies. The 2026 IRP does not evaluate emerging fuel options.
860-090-0060(7)(a)(C)	If the utility's action plan includes any of the following actions, the utility must evaluate portfolios that test the impacts of these actions and that consider alternatives to these actions: (i) A specific resource action that the utility intends to take outside of a competitive acquisition process, such as acquisition of a particular generating facility that does not fall under the competitive bidding rules in OAR Chapter 860, Division 89; (ii) Modification or retirement of a specific resource; or (iii) Expansion, retirement, or substantial modification of transmission, gas transportation, or distribution facilities.	PGE's action plan includes three (3) actions impacting specific resources or facilities, listed in Section 2.2.5. Relevant analysis is discussed in Section 7.4.4, including description of scenarios which test alternatives to each project by removing its availability.
860-090-0060(7)(b)	In developing portfolios under this section, the utility must consider the contributions of all resource options toward reliability, policy compliance, and lowering the costs associated with the generation, production, purchase, or delivery of energy to customers.	Section 4.2 summarizes PGE's modeling approach. Section 7.2 and Section 7.3 describe the range of scenarios tested and rationale.
860-090-0060(7)(c)	The utility must evaluate portfolios under this section across a range of future planning scenarios that reflect plausible and material differences across key planning uncertainties.	Section 6.6 describes the range of external conditions considered. Section 7.3 lists variables tested in portfolios.
860-090-0060(7)(d)	The utility must identify a reference case that represents current expectations for future conditions.	Section 6.1 and Section 6.6 include details of reference case assumptions.

Rule	Requirement	PGE Compliance
860-090-0060(7)(e)	The utility must demonstrate that all portfolios developed under this section provide for an acceptable level of reliability and are expected to meet any reliability requirements to which the utility is subject, while complying with all state and federal energy policies, over the next five years and in key planning years. The utility must describe how the reliability analysis accounts for reasonable opportunities presented by interactions with other systems and markets. Utilities subject to ORS 469A.415 must describe how compliance with the emission reduction targets under ORS 469A.410 was incorporated into IRP modeling.	Section 7.11 describes reliability verification. Appendix Section H.5.4 specifically addresses market interactivity assumptions for reliability analysis. Appendix Section H.2.2.5 describes incorporation of emissions targets in modeling.
860-090-0060(7)(f)	In evaluating portfolios under this section, the utility must reasonably estimate future operations of the utility's system, including interactions between resources and interactions with energy markets.	Appendix Section H.6 explains portfolio modeling methodology, with additional relevant assumptions detailed in Appendix Section H.2, Appendix F, and throughout the IRP.
860-090-0060(7)(g)	For each portfolio, the utility must identify metrics in the IRP that describe the portfolio's performance with respect to:	-
860-090-0060(7)(g)(A)	Long-term costs, calculated as the present value of the expected net costs to Oregon customers over the planning horizon associated with a given portfolio of resources, including all costs associated with producing, purchasing, and transporting energy to the customer and including end effects (comprehensive long-term cost estimate). A comprehensive long-term cost estimate provided under this rule may be used solely for the purposes of evaluating the utility's IRP and, if applicable, CEP.	Section 7.5.2.1 identifies the 20-year NPVRR metric.
860-090-0060(7)(g)(B)	Near-term costs, estimated as a plausible range for the total annual net costs to Oregon customers over the next five years associated with a given portfolio of resources, including all costs associated with producing, purchasing, and transporting energy to the customer (comprehensive near-term cost estimate), considering near-term uncertainties such as resource ownership and cost allocation to Oregon customers. A comprehensive near-term cost estimate provided under this rule may be used solely for the purposes of evaluating the utility's IRP and, if applicable, CEP.	Section 7.5.2.1 identifies the near-term cost metric.

Rule	Requirement	PGE Compliance
860-090-0060(7)(g)(C)	Economic risk, representing the risk associated with near-term plans if future conditions were to materially deviate from expectations.	Section 7.5.2.1 identifies risk metrics. Additionally, Section 7.5.1 presents new analysis on economic risk.
860-090-0060(7)(g)(D)	Reliability risk, presented in a manner that reflects relevant information about the potential frequency and severity of supply shortages, such as total unserved energy, maximum hourly unserved energy, duration, and timing, while considering risks associated with weather, hydrologic conditions, outages, fuel availability, and regional constraints.	Chapter 6.6.1.2 discusses system reliability risk modeling details. Chapter 7.11 describes analysis results.
860-090-0060(7)(g)(E)	Community impacts, presented as plausible ranges for the future impacts of the portfolio on communities within or partly within the utility's Oregon service territory. The utility must demonstrate that community impact metrics are: (i) Developed with input from the public, including input from environmental justice communities; (ii) Quantitative and measurable as the utility implements its plan; (iii) Practically informative to utility implementation decisions, including investments, contracts, and program designs; and (iv) Distinct from other scoring metrics.	Chapter 1, Section 3.1, and Appendix Section C.1 include robust discussion of community considerations. CBI-specific analyses are described in Appendix D with results summarized there and in Section 7.5.2.2 and Section 7.9.
860-090-0060(7)(g)(F)	(F) Emissions, calculated in a manner consistent with any emissions reporting requirements to which the utility is subject.	Chapter 7, including Section 7.5.2.2 summarizes GHG emissions projections. Appendix Section H.2.2.4 describes the calculation methodology in a manner that is consistent with current ODEQ requirements.
860-090-0060(7)(h)	A multi-jurisdictional utility must develop at least one portfolio that optimizes resources across its entire system, considering the varied energy and policy requirements of the jurisdictions in which it operates.	Not applicable to PGE.

Rule	Requirement	PGE Compliance
860-090-0060(7)(i)	Preferred Portfolio. The utility must select a Preferred Portfolio in the IRP and explain why it represents the best balance of cost and risk to customers and the utility. The utility must include a visual representation such as a matrix that describes how each portfolio performed against the portfolio scoring metrics and that clearly demonstrates the relationship of the preferred portfolio to all portfolios eligible for preferred portfolio selection. In the event that the most competitive portfolio is not selected as the preferred portfolio, the utility must provide additional justification for the selection.	Section 7.6 describes PGE's selection of a preferred portfolio. Section 7.5 describes scoring results and includes comparison of all portfolios across all metrics.
860-090-0060(8)	Other planning processes. The utility must clearly refer in the IRP to any additional planning required by law that affects the utility's long-term resource strategy or near-term action plan.	PGE's IRP considers all applicable policies, as summarized in Chapter 3. PGE's joint filing of the IRP with the CEP centers HB 2021 requirements in IRP analysis and actions.
860-090-0060(9)	Long-term resource strategy. The utility must describe in the IRP the long-term resource strategy to meet customer needs and comply with all federal and state energy policies over the next 20 years. The utility's development of the long-term resource strategy must be informed by a needs assessment and portfolio analysis that considers all reasonably plausible resource options. In addition, the utility must include in the resource strategy:	Section 1.5.1 presents the long-term resource strategy.
860-090-0060(9)(a)	An explanation of its consideration of the potential impacts of future technological development and changes to consumer behavior, state and federal energy policies, and regional developments;	Included in Section 1.5.1, see above. Chapter 3 and Appendix G also describe these considerations.
860-090-0060(9)(b)	A description of the utility's strategy for addressing major risks, key dependencies, barriers to implementation, and critical junctures for the plan; and	Included in Section 1.5.1.
860-090-0060(9)(c)	A description of any enabling strategies that the utility is evaluating to support the long-term resource strategy, including changes to system operational practices.	Included in Section 1.5.1.

Rule	Requirement	PGE Compliance
860-090-0060(10)	Near-term action plan. The utility must include in the IRP a near-term action plan that describes the steps the utility intends to take over the next five years to provide customers with safe and reliable service, meet other customer needs and comply with all federal and state energy policies in a manner that is informed by the utility's portfolio analysis and consistent with the utility's long-term resource strategy. The utility must include in the action plan the utility's plans for:	Section 2.2 presents the near-term action plan.
860-090-0060(10)(a)	Resource acquisitions, including conducting competitive acquisitions, with information on the utility's intended schedules, estimated range of procurement scope or size, and any constraints or parameters that the utility intends to apply to align resource selections with the utility's near-term needs and long-term resource strategy.	Included in Section 2.2.
860-090-0060(10)(b)	Pursuing energy efficiency, demand response, community-based resources, and other customer-sited and distributed resources. The action plan must explain how the utility intends to pursue all cost-effective energy efficiency and demand response and must reference analysis in the IRP that supports targets for using these resources to meet system needs.	Included in Section 2.2.
860-090-0060(10)(c)	Any other resource actions the utility intends to take that may materially affect the utility's resource portfolio or the performance of the portfolio in terms of cost, risk, reliability, or compliance with state or federal policies.	Included in Section 2.2.
860-090-0060(10)(d)	Any enabling strategies the utility plans to pursue to support the utility's near-term action plan.	Included in Section 2.2.
860-090-0060(10)(e)	Preparing and filing the next IRP and IRP Updates, including the intended filing dates and any areas that the utility plans to prioritize for new or updated analysis.	Included in Section 2.2.
860-090-0060(10)(f)	Managing near term uncertainties and process dependencies, including any contingency plans the utility has developed to implement the action plan as conditions change.	Included in Section 2.2.

Rule	Requirement	PGE Compliance
860-090-0060(11)	Cost-effective grid enhancing technologies strategic plan. An electric company subject to Oregon Laws 2025 Chapter 391 must include a section that provides its strategic plan setting forth the information required by that law, using the definition of cost-effectiveness and criteria established by the Commission.	Appendix J includes the specified information.
860-090-0060(12)	Counterfactual portfolio. Notwithstanding the requirements of subsection (7)(e) above, an electric company that is subject to ORS 469A.445 must develop and evaluate in the IRP one portfolio developed as though the requirements of ORS 469A.400 to ORS 469A.475 did not apply, holding equal all other constraints and assumptions used to develop the Preferred Portfolio.	Chapter 7 describes development and scoring results of Reliability Only portfolios, in which HB 2021 emissions targets are removed as a constraint. Appendix Section I.1 provides additional description.
860-090-0070(1)	As it is developing the IRP and in advance of filing the IRP, the energy utility must prepare drafts of the following information:	PGE shared applicable drafts during Technical Roundtable discussion webinars. See Appendix Section C.2 and below.
860-090-0070(1)(a)	Portfolios that the utility intends to test in its development of the IRP;	"Scenario designs" first presented at Roundtable 26-1 (14 Jan. 2026); "Portfolio Analysis Scenarios" revisited at Roundtable 26-4 (20 May 2026).
860-090-0070(1)(b)	Future planning scenarios;	"Price Futures Update" presented at Roundtable 26-3 (8 Apr. 2026) and "Corporate Load Forecast Update" presented at Roundtable 26-5 (10 Jun. 2026).
860-090-0070(1)(c)	Community impacts metrics;	"Community Benefit Indicators" presented at Roundtable 26-4 (20 May 2026); "Community Impacts Metrics" presented at Roundtable 26-5 (10 Jun. 2026); "Resource CBIs" presented at Roundtable 26-7 (27 Aug. 2026).
860-090-0070(1)(d)	Near-term action plan; and	"Draft Action Plan" presented at Roundtable 26-7 (27 Aug. 2026)
860-090-0070(1)(e)	Narrative explanation of the utility's response to any specific direction from the Commission since the filing of the prior IRP to undertake or provide additional information, analyses or actions in the IRP.	Table 40 in this appendix identifies chapters and appendices detailing PGE's compliance with specific direction previously received from the Commission.

Rule	Requirement	PGE Compliance
860-090-0070(2)	The utility must solicit public input on each draft element of the IRP sufficiently in advance of making final determinations with respect to that element to fully evaluate the public input it receives for incorporation into the IRP it later files with the Commission.	PGE seeks comments, questions, and discussion during each Technical Roundtable, where feedback is also addressed there and in following meetings and topics presented. PGE also seeks feedback through web-based written feedback forms after each Roundtable; feedback and PGE response are included in Appendix Section C.2.
860-090-0100(1)	In preparing the CEP, the utility must allow a meaningful number of opportunities for engagement that are open to all members of the public. Such opportunities must include opportunities to contribute information and ideas, receive information, and pose questions to the utility including but not limited to requests to run portfolios, futures, scenarios, etc. These opportunities for engagement must include opportunities that are accessible to members of the public with limited resources.	Appendix C describes engagement approaches and opportunities. In addition, PGE's Technical Roundtables are open to all members of the public, summarized in Appendix Section C.2.
860-090-0100(2)	Draft its CEP in language that is as clear and simple as possible, with the goal that it may be understood by non-expert members of the public.	See Chapter 1 Clean Energy Plan.
860-090-0100(3)	Include in its CEP the information required by ORS 469A.415 and annual goals for actions that are consistent with the electric company's long-term resource strategy and action plan.	ORS compliance items are listed in Table 41 in this appendix. CEP analysis covers the 20-year planning horizon and fully aligns with the IRP's near-term action plan and long-term resource strategy, as described in Section 1.5. PGE has not proposed incremental actions specific to the CEP.
860-090-0100(4)	Define and describe in its CEP the community benefits indicators that the electric company plans to track as the company implements its Clean Energy Plan, including the metrics adopted in IRP portfolio scoring.	Section 1.4.2 summarizes PGE's approach, with additional detail in Appendix D.
860-090-0100(4)(a)	The electric company must develop community benefits indicators upon consideration of public input, including input from environmental justice communities in Oregon.	Appendix C describes engagement approaches including the topic of CBIs.
860-090-0100(4)(b)	The electric company must include at least one community benefit indicator that addresses community resiliency.	As described in Section 1.4.3, PGE incorporates resiliency in pCBI, rCBI and iCBI approaches.

Rule	Requirement	PGE Compliance
860-090-0100(4)(c)	The electric company must describe how the community benefits indicators will inform utility implementation decisions through mechanisms such as RFP requirements, RFP non-price scores, and program design criteria and metrics.	Section 1.4.2 summarizes PGE's approach, with additional detail in Appendix D.
860-090-0100(5)	Report measured values for all community benefits indicators defined in the CEP for the previous three (3) years, to the extent available. If measured values for a community benefits indicator are not available for the previous three (3) years, the electric company must explain how it plans to measure that community benefits indicator in future years.	Appendix Section D.4 includes the measured values for all iCBIs.
860-090-0100(6)	Demonstrate in its CEP that the electric company's IRP portfolio analysis accounts for:	
860-090-0100(6)(a)	Any reasonably foreseeable impacts on communities within or partly within the utility's Oregon service territory associated with resource options, including contributions to resiliency; and	Section 1.4.2 and Section 1.4.3 address the specified topics.
860-090-0100(6)(b)	The costs and benefits of offsetting generation from fossil fuel resources with community-based renewable energy resource options.	Section 1.4.4 reviews costs and benefits. Appendix Section G.3 describes the CBRE resource option included in portfolio analysis, with analysis results and considerations further discussed in Section 7.9.
860-090-0100(7)	Include in its CEP targets for community-based renewable energy that facilitate greenhouse gas emissions reductions, promote community resiliency, and are reflected in the utility's near-term action plan and long-term resource strategy.	Section 1.4.4 includes discussion of CBRE outlook with specific CBRE actions detailed in Section 2.2.3.
860-090-0100(8)	Demonstrate in its CEP how the IRP Preferred Portfolio achieves the emissions reductions targets set forth in ORS 469A.410, and include the verification of projected emissions reductions available from the Oregon Department of Environmental Quality pursuant to ORS 469A.420.	Section 1.3.2 presents emissions results of the Preferred Portfolio, which are further described in Chapter 7. PGE is concurrently submitting Preferred Portfolio details to DEQ on Oct. 15, 2026, and will share DEQ's verification to the OPUC docket for PGE's CEP/IRP once received.
860-090-0100(9)	Demonstrate in its CEP how the electric company's long-term resource strategy and near-term action plan provide for the best balance of expected costs and associated risks and uncertainties for the electric company and its customers, while considering impacts to communities and the pace of greenhouse gas emissions reductions.	Section 1.5 describes the long-term strategy and action plan.

Rule	Requirement	PGE Compliance
860-090-0100(10)	Demonstrate in its CEP that the electric company's action plan represents continual progress towards meeting the clean energy targets set forth in ORS 469A.410, including demonstrating a projected reduction of annual greenhouse gas emissions, and that the electric company is taking actions as soon as practicable to facilitate rapid reduction of greenhouse gas emissions at reasonable costs to retail electric consumers.	Section 1.5 describes the demonstration of continual progress.
860-090-0100(11)	Include in its CEP the electric company's two (2) most recent annual emissions data reports filed with the Oregon Department of Environmental Quality.	Greenhouse Gas Emissions reported to ODEQ are available at: https://www.oregon.gov/deq/ghgp/Pages/GHG-Emissions.aspx. Information from these reports for years 2023 and 2024, as well as reported values going back to 2010 are shown in Section 1.2.1.
860-090-0100(12)	Include a narrative explanation and reference to the appropriate CEP section and, if applicable, subsection for the electric company's response to any specific direction from the Commission to undertake or provide additional information or analysis in the CEP since the filing of its last CEP.	Table 40 includes information and references for PGE's responses to guidance received from the Commission Order 24-096 on PGE's 2023 CEP/IRP.
860-090-0100(13)	Cost-effective grid enhancing technologies strategic plan. An electric company subject to Oregon Laws 2025 Chapter 391 must include a section that provides its strategic plan setting forth the information required by that law, using the definition of cost-effectiveness and criteria established by the Commission.	Appendix J includes the specified information.

Table 40. Compliance with 2023 CEP/IRP Acknowledgement Conditions and Direction

Rule or Order	Requirement	PGE Compliance
Order 24-096 (LC 80), VII.A.1	CBRE Actions. We agree with Staff's recommendation to acknowledge PGE's CBRE action item subject to the condition that PGE pursue the broader range of procurement actions that it identified in comments in this docket.	PGE's pursuit of CBREs through an iterative Request for Offers process and continued program progress are discussed in Section 6.3.4 and Section 1.4.4.

Rule or Order	Requirement	PGE Compliance
Order 24-096 (LC 80), VII.A.2	Energy/Capacity Actions. Before issuing its next utility-scale RFP, PGE file a proposal to develop a long lead-time resource RFI via a stakeholder process in LC 80, facilitate a workshop on the RFI findings, and allow sufficient time for stakeholder review of its RFI before proposing its next steps. We agree with PGE's proposed revision to allow PGE to conduct future RFPs as it moves forward with the RFI process. Our expectation is that PGE will present and use the learnings from the RFI process in future procurements.	PGE's RFI results were discussed in the 2023 IRP Update (LC 80, Section 5.6 of IRP Update) and presented at the Dec. 2024 IRP Roundtable.
Order 24-096 (LC 80), VII.A.3	Transmission Analysis and Alternatives. More comprehensive analysis should help to inform PGE's decisions about participating in new regional scale transmission and its valuation of resources that do not require that transmission. It should assist PGE in demonstrating when and at what cost PGE's participation in new regional scale transmission is lower cost and lower risk than resources and load flexibility that do not require significant transmission expansion. Because this analysis addresses longer term considerations and will require more extensive scoping, we direct that it be completed and included in PGE's next IRP/CEP filing.	Chapter 5 describes PGE's modeling approach. Section 7.4 describes inclusion of regional transmission in portfolios.
Order 24-096 (LC 80), VII.B.1	Customer Actions and Guidance for Avoided Cost Update. We adopt Staff's recommendation to direct PGE to work with Staff to propose a new method for calculating avoided costs in docket UM 1893. In addition to Staff's recommendation, 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 sought multiple meetings with Staff during this planning cycle to discuss the UM 1893 methodology and discussion continue. Appendix Section G.8 includes new analysis to continue to inform these discussions.
Order 24-096 (LC 80), VII.B.2	Improved Engagement. We adopt Staff's recommendation to 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 IRP/CEPs.	Appendix C details a range of planning-related topics and activities on which PGE engaged stakeholders, the CBIAG, and communities. See also PGE's Community Engagement Strategy, filed to Docket LC 80 on March 31, 2025.

Rule or Order	Requirement	PGE Compliance
Order 24-096 (LC 80), VII.B.3	CBI by Next Update. 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 IRP/CEP 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.	Informational CBI methodology details and historical data are provided in Appendix Section D.4.
Order 24-096 (LC 80), VII.B.4	Report on Federal Incentives with Next Update. We adopt Staff's recommendation to direct PGE to include a report on federal incentive implementation with its next IRP/CEP update.	PGE's Report on Federal Incentives was included in the 2023 IRP Update (LC 80, Appendix A to IRP Update). This information has been updated in the 2026 CEP/IRP in Appendix O.
Order 24-096 (LC 80), VII.B.5	QF Renewals and Success Rates. [We] 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.	Appendix Section F.2.8 describes QF renewal assumptions for IRP.
Order 24-096 (LC 80), VII.B.6	RECs Discussion in the Next IRP/CEP. We direct PGE to engage in discussions with stakeholders on RECs to clarify how customers are meant to read and understand the information about clean energy and emissions reductions in the company's CEP. We adopt the Energy Advocates' recommendation to direct PGE to include a chapter of its next CEP addressing these issues.	The RECs discussion is introduced in Section 1.2.1, referencing Appendix N.
Order 24-096 (LC 80), VII.B.7	Cost Analysis/Cost Cap. Planning for HB 2021 means planning not only for the emissions reduction targets, but also for the "affordable, clean, and reliable electricity system" that the statute expects regulated utilities to achieve. … going forward we expect that resource planning-at minimum in the identification of annual actions in the CEP-must include greater attention to near-term management of costs and rate pressures.	This CEP/IRP took careful consideration of cost analysis/cost cap further described in Chapter 1, Chapter 2, and appendices referenced there, as well as near-term costs, as required by OAR 860-090-0060(7)(g)(B).

Table 41. Additional ORS and OAR Compliance Items

Rule or Order	Requirement	PGE Compliance
ORS 469A.075	(1) An electric company that is subject to a renewable portfolio standard shall describe the electric company's plan for meeting the requirements of the renewable portfolio standard as part of the electric company's integrated resource plan filed with the Public Utility Commission. (2) At a minimum, a plan for meeting the requirements of the renewable portfolio standard must contain: (a) Annual targets for acquisition and use of qualifying electricity; and (b) The estimated cost of meeting the annual targets, including the cost of transmission, the cost of firming, shaping and integrating qualifying electricity, the cost of alternative compliance payments and the cost of acquiring renewable energy certificates.	Appendix M provides the specified information.
ORS 469A.415(4)	A clean energy plan must:	-
	(a) Incorporate the clean energy targets set forth in ORS 469A.410 (Clean energy targets);	Section 1.2.1 incorporates HB 2021 targets.
	(b) Include annual goals set by the electric company for actions that make progress towards meeting the clean energy targets set forth in ORS 469A.410 (Clean energy targets), including acquisition of non-emitting generation resources, energy efficiency measures and acquisition and use of demand response resources;	Section 1.5 describes PGE's actions, including efficiency and demand response, with additional detail in Section 2.2.
	(c) Include a risk-based examination of resiliency opportunities that includes costs, consequences, outcomes and benefits based on reasonable and prudent industry resiliency standards and guidelines established by the Public Utility Commission;	Section 1.4.3 examines resilience opportunities. Section 7.11 provides details on system reliability analysis.
	(d) Examine the costs and opportunities of offsetting energy generated from fossil fuels with community-based renewable energy;	Section 1.4.4 provides an overview. Section 7.9 describes modeling results.
	(e) Demonstrate the electric company is making continual progress within the planning period towards meeting the clean energy targets set forth in ORS 469A.410 (Clean energy targets), including demonstrating a projected reduction of annual greenhouse gas emissions; and	Section 1.2 describes PGE's continual progress. Section 1.3.2 projects future reductions.

Rule or Order	Requirement	PGE Compliance
	(f) Result in an affordable, reliable and clean electric system.	Addressed throughout Chapter 1.
ORS 469A.415(5)	Actions and investments proposed in a clean energy plan may include the development or acquisition of clean energy resources, acquisition of energy efficiency and demand response, including an acquisition required by ORS 757.054 (Cost-effective energy efficiency resources and demand response resources), development of new transmission and other supporting infrastructure, retirement of existing generating facilities, changes in system operation and any other necessary action.	As described in Section 1.5, PGE's plans emphasize clean energy, demand response, and new transmission.
OAR 860-029-0080(3)	Each public utility must file with the Commission draft avoided-cost information at the time it files its integrated resource plan…	Avoided costs are a combination of portfolio analysis inputs and outputs, including portfolio resource selections (Section 7.6), tuned ELCCs (Appendix Section G.6.4), proxy resource costs (Appendix Section G.7) and energy prices (Section 6.6.2).

Rule or Order	Requirement	PGE Compliance
OAR 860-095-0020(1)-(4)	(1) Electric Companies must provide an Informational Filing to the Commission as a part of their Integrated Resource Plan. The Electric Company's Informational Filing must be included as a chapter to the Integrated Resource Plan that incorporates the Advisory Forecast from a Qualified Regional Program and contains a discussion about how the overall resource strategy interacts with Resource Adequacy concerns. (2) The Informational Filing for an Electric Company must include: (a) Qualified Regional Program data as provided by the Regional Participant that was developed for utilization in the Qualified Regional Program's Advisory Forecast and mirrors the number of years of information provided in the Advisory Forecast. (b) A high-level discussion, not to include confidential information, of the transmission rights necessary to serve P50 load, the transmission rights currently owned or used, the steps that will be taken to procure transmission rights to fill in any open position, and any expected constraints or difficulties in filling any open positions. The information supplied should cover the time period of the two (2) forthcoming Qualified Regional Program operating seasons. (c) A description of information supplied to produce the Advisory Forecast and explanation of any differences between that information and comparable inputs to the Electric Company's Integrated Resource Plan analysis and associated action plan. (d) Commercially and Competitively-sensitive information and data provided in the Informational Filing may be redacted or provided only to Qualified Parties. (3) All outputs of a Qualified Regional Program's most recent Advisory Forecast must be included with the Informational Filing. These may be included in the Informational Filing or as an Appendix chapter to the Integrated Resource Plan. (4) A Regional Participant's most recent Regional Forward Showing submission to its Qualified Regional Program must be made available to Qualified Parties upon request pursuant to a Modified Protected Order.	PGE's Informational Filing is embedded in the IRP. Appendix Section H.10 provides a description and data, including details on PGE's incorporation of Qualified Regional Program data and program-aligned assumptions, with references to applicable Qualified Regional Program outputs. Appendix Section H.6.6 provides context on transmission assumptions for new resource development. Section 7.4.6 explains analysis results and differences.

Appendix C Community Engagement—2026 Clean Energy Plan and Integrated Resource Plan

C.1 Community Engagement Activities Report

C.1.1 Introduction

As part of the 2026 planning cycle, Portland General Electric (PGE) conducted a series of engagement activities to share information about its Integrated Resource Plan (IRP) and create opportunities for community members and the Community Benefits and Impacts Advisory Group (CBIAG) to provide input. These engagement activities were designed to support broader awareness of long-term energy planning and provide accessible opportunities for participation as PGE develops its 2026 IRP and Clean Energy Plan (CEP).

In previous planning cycles, advocates, Staff, and other interested parties noted that traditional resource planning forums, such as IRP Roundtables, were primarily structured for technical audiences. Feedback indicated interest in additional engagement opportunities that provided more accessible information about long-term planning, its purpose, and how planning decisions connect to customers and communities.

In response to this feedback, and consistent with CEP/IRP rules and expectations reflected in the LC 80[137] order No. 24-096, PGE evaluated its existing engagement practices and developed a comprehensive community engagement strategy inclusive of the engagement for long-term planning processes such as the IRP.[138] This approach was informed by conversations with interested parties and by reviewing feedback submitted through regulatory dockets. This strategy was intended to strengthen how PGE shares information, gathers input and creates opportunities for participation in long-term planning discussions, while creating opportunities for meaningful engagement.

This appendix summarizes PGE's engagement strategy implemented during the early stages of the 2026 planning cycle. The following sections are organized using a consistent framework: what we did, what we heard and what we learned through the engagement process. This structure is intended to document key themes, questions, and areas of interest. To organize and better understand the CBIAG engagement, 'what we heard' comments were reviewed using the same four categories featured in the 2025 CBIAG Biennial Report framework: Ask, Concern, Advice, and Education. The categories helped distinguish between requests for clarification, expressions of risk or impact, collaborative recommendations and knowledge contributions that facilitate understanding.

[137] Staff Recommendation 6 - Improved Engagement: We adopt Staff's recommendation to 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 IRP/CEPs. We appreciate the strides PGE has made and recognize that bringing new stakeholders into utility planning takes sustained effort and focus.
[138] https://edocs.puc.state.or.us/efdocs/HAD/lc80had335791056.pdf

The 2026 planning cycle engagement included CBIAG's first focused engagement on PGE's IRP and its connection to the CEP, community engagement at the East County Resiliency Fair and subsequent CBIAG discussions on PGE's All-Source Request for Proposals (RFP), workforce and labor strategy and Community Benefit Indicators (CBIs). Together these activities provided multiple opportunities to introduce planning concepts, answer questions and gather perspectives from CBIAG members and community participants.

C.1.2 CBIAG - CEP & IRP Introduction

C.1.2.1 What We Did

On January 28, 2026, the CBIAG held its first focused discussion on PGE's IRP and its connection to the CEP. Recognizing the technical and regulatory complexity of long-term resource planning, members received advance preparation to support meaningfully engagement.

In November 2025, CBIAG member and community education expert Sherrie Villmark of Community Energy Project led a foundational session on how the electric grid and distribution system planning works. The member-led session helped establish baseline knowledge about generation, transmission, distribution infrastructure and reliability. This preparation helped members engaged in the IRP discussion, deepening members' understanding of how the grid operates and how planning decisions connect to infrastructure and customer impacts.

During the January 2026 meeting, PGE's Integrated Resource Planning team delivered an IRP 101 overview designed in plain language. The presentation addressed:

- What the IRP is: a 20-year roadmap that identifies future energy needs and the optimal portfolio of resources that can best meet future needs.
- Where the IRP fits: its role within PGE planning and regulatory processes, including its connection to the Clean Energy Plan under House Bill 2021.
- Who is involved: PGE teams, the Oregon Public Utility Commission (OPUC), advocacy groups, and other interested parties.
- Plan filing cadence: the frequency with which CEP/IRP analysis is updated and plan is filed.
- Key elements of the combined IRP and CEP: what we need, check what we already have, identify gaps, explore resource options, build a preferred portfolio, identify an action plan.
- Considerations for planning using models, such as assumptions, tradeoffs, and evolving information.
- Why the CEP/IRP is important for the future: it informs procurement decisions, infrastructure investments, and long-term affordability impacts.

Throughout the presentation, members actively engaged in discussion. CBIAG members contributed 21 questions and comments, and the third-party facilitator contributed three (3) additional questions, for a total of 24 IRP-related inputs. PGE provided 28 responses, with several exchanges requiring clarification or additional explanation. Every CBIAG member participated in the discussion providing at least one question or comment, demonstrating active engagement.

C.1.2.2 What We Heard

Each of the 24 IRP-related inputs were assigned one primary category to reflect 100% of engagement.

The discussion reflected an interest in understanding how long-term resource planning works and how it affects customers and communities.

Of the 24 inputs (21 from CBIAG members and three (3) from the third-party facilitator):

- 75% (18 inputs) were categorized as Ask, representing clear requests for information or clarification.
- 17% (4 inputs) were categorized as Concern, reflecting expressions of affordability pressure, equity implications, or reliability risks.
- 4% (1 input) was categorized as Advice, offering a collaborative recommendation to strengthen engagement.
- 4% (1 input) was categorized as Education, where a member contributed contextual knowledge of energy efficiency impacts.

Table 42. Feedback Comment Categorization (Ask / Concern / Advice / Education)

Category	Count	Percent (%)	Description
Ask	18	75%	Request for clarity or action.
Concern	4	17%	Potential impacts, risks, or challenges flagged.
Advice	1	4%	Suggestions or solution-oriented recommendations.
Education	1	4%	Knowledge-sharing feedback.
Total	24	100%	Total number of comments

The majority of comments were included in the Ask category. Members focused on understanding how the 20-year planning horizon works, how often the IRP is updated, how assumptions are developed, how demographic and policy uncertainty are incorporated, and how regulatory oversight functions. Members also asked about portfolio evolution, including PGE's transition away from coal resources and toward renewable energy resources, and about market competition from hyperscale datacenters. Questions were raised about catastrophic risks, such as earthquakes, and how those considerations intersect with long-term planning. Members sought clarity about how community feedback influences decision-making and whether input must be incorporated or remains advisory.

Concern inputs centered primarily on affordability and equity. Members expressed that even a $200 monthly bill can be burdensome and asked how affordability tradeoffs are evaluated within long-term planning. Reliability for households dependent on electrically powered medical or assistive technologies was raised as an area of impact. The comments demonstrated that members consistently apply a customer-centered lens to technical planning discussions.

Advice and Education categories, while fewer in number, were substantive. Members offered to partner with culturally specific leaders to strengthen outreach and shared insights about how they

can provide feedback on resource planning. In addition, a member shared how energy efficiency technologies such as LEDs and heat pumps can reduce consumption even as electrification increases load. These contributions indicate growing familiarity with grid dynamics and planning tradeoffs.

Overall, the engagement demonstrated that members were interested in building technical understanding while grounding the discussion in real-world affordability, reliability and customer impacts. The discussion showed strong interest in understanding IRP concepts while consistently grounding questions in tangible, downstream impacts. Members gravitated toward how planning decisions translate into programs, affordability, reliability, and real-world customer experience—areas where they feel most connected and informed.

C.1.2.3 What We Learned

This first IRP engagement demonstrated that CBIAG members are open and interested in learning about resource planning when it is presented in an accessible, foundational way that clearly connects to customer impacts.

Members sought to understand what the IRP is, how it works, how assumptions and tradeoffs are developed, how feedback is incorporated, and how decisions affect customers. At the same time, discussion consistently gravitated toward tangible, downstream impacts, particularly how planning decisions translate into programs, affordability, and reliability. Highly technical elements were less central to member input, reflecting where members feel most comfortable engaging and where they see the greatest relevance.

Affordability remained the primary concern. Members reiterated that even moderate monthly bills can be burdensome, and affordability was referenced in roughly one-third (1/3) of meeting comments. Survey data also confirmed cost of energy as the top-ranked concern. Members showed interest in understanding the mechanics of the grid and the evolution of the resource portfolio. The November grid session enabled deeper engagement in January, demonstrating that building foundational knowledge strengthens participation and confidence.

Survey Results

The post-meeting survey results reinforced the effectiveness of our approach.

All eight survey respondents rated the IRP presentation positively.

- 100% (8 of 8 respondents) either agreed or strongly agreed the content was relevant and useful.
- 100% (8 of 8) agreed or strongly agreed the presentation increased their knowledge of the subject.
- 100% (8 of 8) agreed or strongly agreed the presentation was well organized and easy to follow.
- Notably, 4 of 8 respondents (50%) selected Strongly Agree across all three (3) evaluation measures, reflecting particularly strong confidence in the session's clarity and value.

Overall, the results indicate that a plain-language, foundation-first approach is effective, and that members are most engaged when planning can be connected to real-world customer and community impacts.

CBIAG Survey Results

CBIAG members were surveyed following the January meeting. The following section provides results from that survey.

Priorities for Long-term Planning

When asked what should be prioritized (members could select up to three (3) options) in long-term planning, members most frequently selected:

- Increasing community benefits (selected by 7 of 8 respondents)
- Prioritizing affordable power bills (6 of 8 respondents)
- Increasing clean energy resources (6 of 8 respondents)
- Improving resiliency of grid infrastructure (3 of 8 respondents)
- Considering reliability and frequency of outages (3 of 8 respondents)

The allowance of multiple selections indicate that when not asked about which single consideration to prioritize, members do not view clean energy, reliability and affordability as competing priorities, but rather as interconnected planning considerations.

Ranking of Energy Concerns

When respondents ranked their top energy concerns:

- Cost of energy / monthly bills was ranked as the top concern by the majority of respondents (5 of 8 ranked it #1).
- Extreme weather impacts and outages / reliability were most frequently ranked second or third.
- Wildfire impacts / public safety power shutoffs generally ranked in the middle.
- Clean energy transition ranked lower overall compared to affordability and reliability concerns.

Rankings demonstrate that while clean energy remains a priority, immediate affordability pressures and reliability risks are most important for members.

Qualitative Feedback

Lastly, open-ended responses were limited, but positive. One member noted appreciation for learning more about long-term planning and better understanding PGE's role. No substantive concerns were raised in the open-response section.

Survey results demonstrated the IRP overview successfully increased member knowledge and supported meaningful engagement. All respondents reported increased understanding of the Integrated Resource Plan, and all rated the presentation as relevant and well organized. Members identified affordability, reliability, community benefits and the clean energy transition as top

planning priorities. These priorities aligned closely with questions and concerns raised during the meeting discussion. Survey responses also reinforced that members value early education and transparency in long-term planning processes.

Future engagement and learning opportunities will support informed participation in relevant forums as of interest, which may include IRP or other planning efforts, but broadly interest was more focused on real-world affordability, bill impacts, and customer programs.

C.1.3 East County Resiliency Fair

On Saturday, February 21, 2026, PGE participated as a sponsor and exhibitor at the East County Resiliency Fair hosted by the Community Services Network (CSN), City of Portland Bureau of Planning and Sustainability and the City of Gresham. The event, held at Centennial High School, invited community members to access a wide range of services and resources, with a strong focus on reaching historically under-resourced communities and those with limited access to support.

The fair brought together multiple agencies and organizations offering direct services, including a kid's helmet giveaway, medical sharps disposal, repair café services, health enrollment support, and bill discount enrollment assistance. Metro also provided safe disposal services for medical sharps, compact fluorescent bulbs, and household batteries, reinforcing the event's emphasis on accessible, practical community resources. PGE's participation marked the first introduction of CEP and IRP education into a community fair setting. The approach was intentionally designed to meet people where they were already accessing services, leveraging a trusted and well-established community event model that CSN and its partners have successfully hosted over time.

PGE coordinated with Energy Trust of Oregon and Community Energy Project to align educational content and offer complementary workshops. As part of this effort, PGE facilitated a workshop titled "How PGE Plans for the Future," presented by a Principal Integrated Resource Planning Analyst. The session provided a plain-language overview of how PGE develops its IRP and CEP, how long-term resource planning decisions are made, and how those decisions affect customers.

The engagement paired long-term planning education with energy efficiency and weatherization workshops led by Community Energy Project and Energy Trust of Oregon, creating a coordinated experience that connected planning concepts to immediate, tangible household supports. The East County Resiliency Fair created an opportunity for PGE to connect with community members. Event organizers reported approximately 558 attendees, representing about 175 heads of household, indicating a strong turnout at the event. PGE staff distributed 72 Project Zero youth clean energy educational bags, reflecting engagement with families and younger attendees.

C.1.4 Clean Energy Plan and Integrated Resource Plan Community Workshop

C.1.4.1 What We Did

During the resiliency fair, PGE facilitated a workshop titled "How PGE Plans for the Future" to provide attendees with an accessible introduction to long-term resource planning. The session was designed to explain how PGE plans to meet future electricity needs while balancing affordability, reliability and clean energy goals.

The presentation began by explaining as a regulated electric utility, PGE is required to plan ahead through a structured, data-driven process. The IRP was introduced as one of the primary tools used to evaluate how the company can meet projected electricity demand over a 20-year horizon. Participants were told IRP is the long-term roadmap that identifies future energy needs and the optimal portfolio of resources that can best meet those future needs.

To help contextualize the IRP within the broader regulatory process, the workshop was originally designed to walk through how long-term planning connects to utility decisions, including how the IRP progresses through procurement and ultimately regulatory review at the Oregon Public Utility Commission (OPUC).

However, during the session, we adjusted the approach in real time based on participant engagement and the need to ensure the content was accessible and relevant. Rather than moving through a detailed, structured presentation, we focused on shorter, simplified explanations and shifted into a more dialogue-based format. This allowed participants to engage with concepts in a way that connected more directly to what mattered most to them, while keeping the discussion interactive and grounded.

In its simplified form, the workshop still introduced the core progression of planning. Participants learned that the IRP is the first step in a multi-stage process that includes resource procurement and regulatory review. This includes forecasting long-term energy needs and developing a near-term action plan, procuring supply and demand-side resources such as generation, energy efficiency, and demand response, and then implementing investments and recovering costs through rates following regulatory approval. This framing helped connect long-term modeling to real-world customer bill impacts.

The cadence of planning was also shared at a high level, noting that the full IRP is developed approximately every three (3) years, with annual updates to reflect changing conditions.

Rather than focusing heavily on technical detail, the discussion emphasized that planning is a collaborative process involving multiple perspectives. It includes internal PGE teams across planning, operations, rates, regulatory affairs, and business strategy, as well as external input from the Oregon Public Utility Commission, environmental organizations, consumer advocates, and other interested parties. This helped reinforce that long-term planning reflects a range of inputs and priorities.

Participants were introduced to core planning concepts such as forecasting future electricity demand, evaluating system needs, and using scenario modeling to understand how different resource combinations can balance cost, risk, and reliability. We also discussed how uncertainty, policy shifts, technology changes, resource availability, and load growth all influence planning decisions.

The conversation concluded by grounding the purpose of planning in customer and community impact. Participants reflected on how long-term planning helps reduce surprises, support reliability, manage affordability pressures, and guide the transition toward cleaner energy resources, while ensuring the system continues to meet everyday needs.

C.1.4.2 What We Heard

During the workshop, participant interest varied across the content. Approximately a quarter of attendees engaged directly with the IRP topic itself, while the majority of questions and discussion centered on how long-term planning connects to affordability and customer bills.

Much of the conversation shifted toward how broader policy and system decisions, including the growth of large energy users such as datacenters, may influence costs, demand, and ultimately customer impacts. The identified themes shaped the majority of the Q&A, reinforcing that participants were most focused on understanding how planning decisions translate into affordability outcomes and real-world bill impacts.

Participants also expressed appreciation for PGE's presence at the fair and for hosting the workshop in a community setting. At the same time, they were direct and candid in raising concerns about affordability, underscoring how central cost pressures are in their day-to-day experience.

C.1.4.3 What We Learned

Following the workshop, participants were invited to complete a voluntary and anonymous post-workshop survey. The survey was designed to capture both quantitative and qualitative feedback about the presentation and participants' perspectives on long-term energy planning.

The survey included four scaled or ranking-based questions and one open-ended question for qualitative feedback. Two of the questions—priorities for long-term planning and ranking energy concerns—were also asked of CBIAG members during their IRP discussion. This alignment allowed for comparison between workshop participants and CBIAG members who received a similar presentation.

Thirteen (13) participants attended the workshop, and three (3) participants completed the survey. While the sample size was small, it reflects a broader engagement challenge for this topic area, which required incentives to encourage attendance and resulted in limited voluntary survey participation. This underscores that long-term resource planning is not an inherently easy topic to attract or sustain participation around in a community setting. Even so, the responses provide insight into how community members interpreted the information presented and how they think about long-term energy planning priorities.

Overall Workshop Value

All respondents strongly agreed (3 of 3, 100%) that the workshop was a valuable use of their time. This result suggests the presentation was well received and participants found the information relevant and worthwhile.

Most Useful Topic

Participants were asked which topic they found most useful during the session. Responses highlighted the value of foundational education in the planning process.

- Two respondents (67%) selected learning about what the Clean Energy Plan and Integrated Resource Plan.
- One respondent (33%) selected learning who is involved in developing the plan and why.

- The responses suggested, participants were most interested in understanding the structure of the planning process itself—what the IRP and CEP are and how decisions are made—before exploring more technical or modeling or process details.

Priorities for Long-term Planning

Participants were then asked, based on what they learned during the presentation, what would you prioritize most in long-term planning. Respondents could select up to three (3) priorities.

Across the three (3) responses, several themes emerged:

- Prioritizing affordable power bills was selected by all respondents (3 of 3, 100%).
- Increasing clean energy resources was also selected by all respondents (3 of 3, 100%).
- Improving resiliency of grid infrastructure was selected by two respondents (67%).
- Considering power reliability and frequency of outages was selected by one respondent (33%).

Although the sample size was limited, respondents expressed support for long-term planning that advances clean energy resources while maintaining affordable bills and strengthening grid resilience.

Ranking of Energy Concerns

Participants were asked to rank their concerns related to energy. The results reflected a mix of affordability, reliability and climate-related risks.

Across responses:

- Cost of energy / monthly bills appeared near the top of rankings in multiple responses, indicating affordability remains a central concern.
- Outages and reliability were ranked highly by at least one respondent and remained a consistent concern across responses.
- Extreme weather impacts and wildfire impacts / public safety power shutoffs appeared in the middle of rankings.
- Clean energy transition was ranked lower relative to immediate concerns about affordability and reliability.

The results are directionally consistent with patterns seen in other engagement activities, where customers prioritize affordability, while still supporting progress toward clean energy goals.

Qualitative Feedback

The survey included one open-ended question asking whether participants had anything they wanted PGE to hear or consider as part of future planning.

Two responses were submitted:

- No.
- Datacenters.

Although brief, the reference to datacenters here and questions during the workshop indicate awareness of growing electricity demand from large loads and interest in how these developments affect planning and costs.

C.1.5 PGE Long-term Planning Booth

C.1.5.1 What We Did

At the East County Resiliency Fair, PGE hosted several informational tables designed to connect community members with resources, programs, and educational materials related to energy affordability, planning, resiliency, and workforce development. Staff engaged with attendees to answer questions, provide program information, and supported customers in accessing available services. The tables also served as an opportunity to share information about the traditional and modern grid and resource planning while highlighting programs and initiatives that directly support customers and communities. PGE's Spanish-speaking staff were present at the booth and courtesy of CSN, other translators, to support accessibility needs so attendees could comfortably ask questions, complete surveys and receive information in their preferred language.

Below are brief descriptions of what the PGE information tables included:

- Income-Qualified Bill Discount (IQBD) provides monthly bill assistance to eligible customers based on household income. At the event, PGE staff assisted customers with eligibility screening, enrollment support and general billing questions.
- Resource planning and grid education table provided educational information about how PGE plans for future energy needs through the IRP and CEP. Visual materials illustrated how the traditional grid differs from the modern grid and how long-term planning relates to reliability, affordability and clean energy goals.
- Transportation electrification information was shared about PGE's transportation electrification initiatives, including electric vehicle (EV) charging infrastructure, customer incentives and efforts to support access to EV programs. Discussions focused on how electrification supports emissions reduction goals while considering grid impacts and infrastructure needs.
- Preparedness and resiliency table provided resources related to outage preparedness, extreme weather readiness and public safety power shutoff awareness. Materials highlighted how customers can prepare for outages and how PGE incorporates resiliency considerations into planning and operations.
- Clean energy workforce opportunities information was shared about workforce development and connection to the clean energy transition. This included apprenticeship programs, training opportunities and career pathways related to grid modernization, renewable energy development and electrification initiatives.

PGE hosted a dedicated table focused on resource planning and grid education, designed to introduce community members to how the electric system works and how PGE plans for future energy needs through the Integrated Resource Plan (IRP) and Clean Energy Plan (CEP). The table created an opportunity to engage directly with fair attendees in a more informal and accessible

setting - an approach that differs from traditional resource planning discussions, which are typically held in technical forums or formal meetings. PGE staff engaged directly with attendees through informal conversations, using visual materials and simple explanations to describe how electricity moves from generation resources through transmission and distribution infrastructure to homes and businesses. Staff walked participants through how the traditional electric grid differs from the modern grid and explained how long-term planning helps ensure the system remains reliable, affordable, and capable of supporting new technologies such as renewable energy resources and electrification.

The table created an opportunity for individuals who did not attend the formal workshop to learn about long-term resource planning in a quick and informal setting. Staff were able to provide brief explanations of the IRP and CEP planning process and explain how these plans guide future energy investments, procurement decisions, and infrastructure development.

As part of the engagement, staff invited visitors to participate in a short anonymous three-question survey designed to better understand customer priorities and concerns related to energy planning. Participation was voluntary, and attendees could complete the survey at the table after speaking with staff.

The table generated strong engagement throughout the event. About 100 individuals visited the table, and 32 participants completed the survey, providing valuable insight into community perspectives on energy affordability, energy related concerns and long-term planning priorities.

This informal engagement approach allowed PGE to interact with community members in a conversational and accessible way while gathering feedback that could help inform future outreach and planning discussions.

Event attendees largely represented environmental justice (EJ) communities,[139] providing insight into customer perspectives from communities historically most impacted by affordability challenges.

C.1.5.2 What We Heard

Through conversations at the PGE booth, employees engaged with approximately 100 community members and shared information about long-term energy planning. Participants asked questions about PGE's role as a utility, how the electric grid operates, and how long-term planning connects to the customer. Affordability remained a recurring theme, with participants raising questions about energy costs and monthly bills. Also, PGE observed that some attendees expressed appreciation for having utility representatives present at the resource fair and valued the opportunity to ask questions directly and receive information in real-time. Conversations with attendees provided insights into community interests and highlighted areas where additional awareness and outreach may be helpful.

[139] "Environmental justice communities" includes communities of color, communities experiencing lower incomes, tribal communities, rural communities, coastal communities, communities with limited infrastructure and other communities traditionally underrepresented in public processes and adversely harmed by environmental and health hazards, including but not limited to seniors, youth and persons with disabilities.

C.1.5.3 What We Learned

At our booth we invited attendees visiting the booth to complete a short survey to better understand customer priorities and concerns related to energy. Participation in the survey was voluntary and anonymous.

A total of 32 responses were received, and the survey included four scaled or ranking-based questions and one open-ended question designed to capture qualitative feedback. The ranking question asked participants to identify their biggest energy concerns and the other question asked what they would prioritize most in long-term planning.

While the survey represents a small and self-selected group of event participants, the responses provide insight into how customers think about energy, affordability and the clean energy transition.

Ranking of Energy Concerns

Participants were asked to rank their biggest concerns related to energy, with the top position representing the greatest concern. Across responses, cost of energy / monthly bills emerged as the most frequently ranked top concern.

The overall pattern of responses suggests the following general order of concern:

1. Cost of energy / monthly bills
2. Extreme weather (heat, cold, storms)
3. Outages and reliability
4. Clean energy transition
5. Wildfire impacts / public safety (proactive) power shutoffs

The responses indicated affordability remains the most consistent concern among participants, while reliability and climate-related risks were also important considerations. Several respondents ranked extreme weather impacts highly, reflecting growing concern that hotter and colder weather can increase energy usage and contribute to higher electricity bills. Although wildfire impacts and public safety power shutoffs were ranked lower overall, they were still identified as significant concerns by several respondents.

Priorities for Long-term Planning

In the second question of the survey, participants were asked what they would prioritize most in long-term planning (could select up to three options). The responses indicated a strong emphasis on affordability, followed by clean energy and reliability considerations. Table 2 summarizes the distribution of responses across the identified planning priorities.

The most frequently selected priority was keeping power bills affordable, selected by 22 respondents. Participants identified increasing clean energy resources as an important planning priority, indicating continued support for the clean energy transition. Reliability-related priorities, including considering outage frequency and improving grid resiliency, were also commonly selected.

Table 43. Priorities for Long-term Planning

Priority	Number of Responses
Prioritizing power bill affordability	22
Increasing clean energy resources	12
Considering power reliability and frequency of outages	10
Improving resiliency of grid infrastructure	9
Increasing community benefits	5

Taken together, the responses suggest that participants are interested in a balanced approach to long-term planning, where affordability, reliability, and clean energy progress are considered together.

Qualitative Feedback

The final survey question invited participants to share additional feedback on what they wanted PGE to consider in future planning. Thirteen respondents provided written comments, offering additional context to the ranking responses. Although the comments were brief, some themes emerged: affordability and broader system planning considerations.

Affordability

The most common theme in the responses related to energy costs and affordability. Several comments directly referenced the cost of electricity or the need for expanded assistance programs. Examples included:

- Cost
- Cost relief for low-income households
- Expand the income discount benefits to cover more income levels
- More programs for renters to lower bills – or outreach if they exist

These comments reinforce the survey's quantitative results, where cost of energy / monthly bills ranked as the top concern and prioritizing affordable power bills was the most frequently selected long-term planning priority.

System Planning and Future Energy Demand

A smaller number of comments referenced longer-term infrastructure or planning considerations. These responses reflected interest in how the energy system evolves and how emerging demand may affect planning decisions.

Examples included:

- Transmission lines
- Solar energy and renewable energy
- Datacenter overconsumption. They should be held accountable.

Together, these comments reflect community interest in grid infrastructure, renewable energy development, large-load demand such as datacenters, and targeted outreach to specific customer groups.

Overall, the qualitative responses reinforce the patterns observed in the survey's ranking questions. Affordability emerged as the most prominent concern, while respondents expressed interest in how infrastructure investments and large energy users may shape future planning, as these topics are of concern to have rising costs and/or local environmental and neighborhood impacts.

C.1.6 CBIAG meeting—PGE's All—Source Request for Proposal (RFP) 101

C.1.6.1 What We Did

On February 25, 2026, CBIAG continued its discussion on long-term energy planning, focusing on PGE's All-Source Request for Proposals (RFP) process. Building on prior CEP and IRP discussions, this session centered on how near-term actions are implemented.

PGE explained that, as a regulated utility, it uses All-Source RFPs to procure new energy resources when future needs are identified through long-term planning. These RFPs are open to a range of technologies, including wind, solar, and battery storage, and allow developers to submit competitive proposals.

The RFP process translates long-term plans into action by identifying and selecting projects that can meet customer needs at the lowest cost while maintaining reliability. It is designed to ensure fair competition, transparency, and regulatory oversight.

PGE also shared that the Oregon Public Utility Commission reviews and approves the RFP process, with independent oversight to ensure fairness. Recent and current RFPs were highlighted to show how this process results in new energy projects that will serve customers in the coming years.

The session concluded by emphasizing that All-Source RFPs are a key tool for delivering clean, reliable, and affordable energy, while continuing to evolve to better incorporate community benefits.

C.1.6.2 What We Heard

A total of seven comments and questions were recorded during the RFP discussion with the majority (71%) focused on clarification. Members asked about who submit proposals, whether utilities can participate in other utilities' RFPs, how project capacity translates to service for customers and how resource gaps are addressed if proposals received do not fully meet projected energy needs. These questions highlighted members' interest in better understanding the technical and regulatory processes that guide long-term resource planning.

A smaller number of comments focused on key concepts, including a request to clarify least cost, least risk, and how affordability, reliability, and system needs are balanced in project evaluation.

Across the discussion, an ongoing theme was members' greater interest in how RFPs connect to community benefits and equity, rather than the technical details of resource procurement. Members raised questions about how these considerations are incorporated into the RFP process and whether they are more meaningfully addressed through other programs or investments. Overall,

the discussion highlighted members' interest in learning how planning translates into project selections with community impact more than any focus on technical modeling or analysis.

Table 44. Feedback Comment Categorization for All-Source RFP (Ask / Concern / Advice / Education)

Category	Count	Percent (%)	Description
Ask	5	71%	Request for clarity or action.
Concern	0	0%	Potential impacts, risks, or challenges flagged.
Advice	1	14%	Suggestions or solution-oriented recommendations.
Education	1	15%	Knowledge-sharing feedback.
Total	7	100%	Total number of comments

C.1.6.3 What We Learned

Survey Results

Following the February CBIAG meeting, members were invited to complete a post-meeting survey on the All-Source RFP presentation, including content relevance, clarity, and knowledge gained. Eight responses were received.

Overall, feedback was positive. All respondents (100%) agreed or strongly agreed the content was relevant and useful, indicating strong alignment with member interests and understanding of how the RFP process fits within long-term planning. Most respondents (88%) reported increased knowledge of the All-Source RFP process, suggesting the presentation was effective in building familiarity with how utilities procure new energy resources. Similarly, 88% found the presentation well organized and easy to follow.

Open-ended responses reinforced these findings, with participants noting the value of the background information and clarity of the content. One respondent shared that the format made it easy to follow, even as a first-time attendee.

While feedback was largely positive, it also highlighted opportunities to strengthen how complex topics are presented. Future engagement will focus on incorporating more interactive elements, clearer emphasis on key points, and approaches that support understanding for a general audience while maintaining technical accuracy where relevant.

C.1.7 CBIAG—Community Benefit Indicators (CBIs)

C.1.7.1 What We Did

On April 22, 2026, the CBIAG met to discuss Community Benefit Indicators (CBIs). The session revisited the original 2024 CBI framework, reviewed prior CBIAG input, and discussed how community benefits will continue to be measured, refined, and tracked through the 2026 IRP and CEP cycle and beyond.

PGE reintroduced the CBI framework to reinforce its purpose and connection to long-term planning. CBIs help link utility planning decisions to community outcomes and respond to OPUC expectations for more measurable tracking of community impacts. PGE also noted how community

benefit considerations are incorporated into long-term planning, portfolio development, and clean energy compliance requirements under HB 2021.

The original framework includes five key categories: economic impacts, energy equity, health and community wellbeing, resilience and reliability, and environmental impacts. These categories reflect outcomes related to jobs and economic opportunity, affordability, and access, public health, grid reliability, and emissions reductions.

PGE reviewed how CBIs are applied across three (3) planning pathways to reflect community impacts throughout the planning process. At the resource level, CBIs inform evaluation of individual resource options alongside cost and system needs. At the portfolio level, they support comparison of different resource mixes based on expected community outcomes in addition to traditional planning criteria. At the informational level, CBIs are used to track real-world outcomes over time, helping assess whether intended community benefits are being realized.

Finally, PGE shared its intent to continue refining the CBI framework through the 2026 CEP and IRP process in collaboration with CBIAG, IRP Roundtable participants, and other stakeholders, with a focus on improving measurement, tracking, and transparency of community benefits.

C.1.7.2 What We Heard

The CBIAG discussion reflected an interest in how CBIs are defined, prioritized and applied within long-term planning processes. Members consistently connected the conversation back to real-world customer and community impacts, particularly affordability, economic stability, health, and reliability.

Affordability and economic impacts emerged as central themes throughout the discussion, with members noting that cost-of-living pressures continue to shape how customers experience utility decisions. Participants questioned whether economic impacts should be elevated further within the CBI framework, reinforcing the importance of affordability in long-term planning discussions.

Members sought greater clarity on how CBIs are operationalized in practice, including how indicators are weighted, how customer reach and local context are considered, and how PGE determines which indicators are prioritized during the planning process. Several members expressed interest in additional opportunities for collaborative discussion around rankings, metrics, and desired outcomes.

The discussion explored environmental and community-level impacts, representation in the engagement process, and the broader tradeoffs involved in balancing affordability, reliability, environmental outcomes, and community benefits within utility planning.

Using the CBIAG engagement framework, most comments (57%) were categorized as Ask, reflecting strong interest in understanding how CBIs are defined, measured, prioritized, and applied within the CEP and IRP framework. Approximately 21% of comments were categorized as Concern, primarily related to representation, metric development, and the complexity of ranking community benefits. Advice comments (14%) focused on opportunities for additional collaborative discussion, while one comment (7%) was categorized as Education, where a member shared broader contextual insight related to utility profitability and investment tradeoffs.

Overall, the discussion demonstrated that members are interested not only in understanding the CBI framework, but also in helping shape how it evolves over time through continued discussion, clearer definitions, and transparent methodologies.

Table 45. Feedback Comment Categorization for All-Source CBI (Ask / Concern / Advice / Education)

Category	Count	Percent (%)	Description
Ask	8	57%	Request for clarity or action.
Concern	3	21%	Potential impacts, risks, or challenges flagged.
Advice	2	14%	Suggestions or solution-oriented recommendations.
Education	1	7%	Knowledge-sharing feedback.
Total	14	100%	Total number of comments

C.1.7.3 What We Learned

Members were highly engaged in the discussion on CBIs and recognized that community benefits are complex and may reflect a range of perspectives. There was strong interest in continuing the conversation, particularly around how community benefits are defined, prioritized, and balanced across different outcomes and values.

This topic clearly resonated with members, and they expressed interest in ongoing engagement as the framework continues to evolve.

Survey Results

The post-meeting survey results demonstrated that CBIAG members were engaged in the Community Benefit Indicator (CBI) discussion and interested in continuing to refine how community benefits are defined, measured, and prioritized within the Clean Energy Plan (CEP) and Integrated Resource Plan (IRP) processes.

Overall, survey responses indicated the presentation was generally viewed as relevant and informative. Of the eight (8) responses received:

- Seven (7) respondents (88%) agreed or strongly agreed that the content presented was relevant and useful.
- Six (6) respondents (75%) agreed or strongly agreed that the presentation increased their knowledge of the subject.
- Seven (7) respondents (88%) agreed or strongly agreed that the presentation was well organized and easy to follow.

The results suggested the presentation supported member understanding of the CBI framework, while also highlighting opportunities to continue strengthening how these concepts are communicated and discussed.

A key takeaway from the survey demonstrated members are interested in greater clarity and specificity around CBIs. Several respondents noted that some of the proposed categories felt broad, overlapping, or difficult to distinguish from one another. Members requested clearer

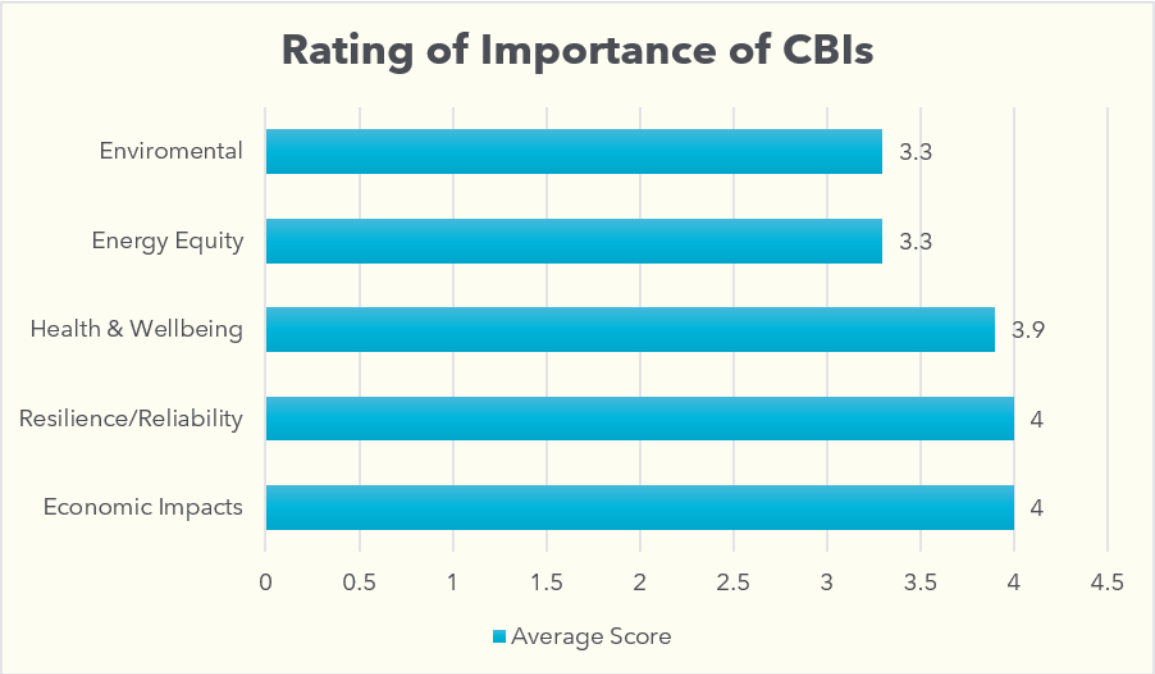
definitions, more discussion about metrics and desired outcomes, and additional opportunities to explore how community benefit outcomes should be prioritized if tradeoffs are necessary. These comments indicate that while members support the concept of CBIs, they are seeking a more refined and actionable framework that can support meaningful discussion and evaluation.

CBIAG members were asked to rate the importance of five proposed community benefit outcome areas to their communities using a scale of 1 to 5, where:

- 1 = Least important
- 5 = Most important

A total of eight (8) respondents completed the ranking exercise. To understand overall trends across responses, average scores were calculated for each outcome category. Using an average score methodology allowed responses from all participants to be combined into a single comparable measure for each category, helping identify which outcomes were generally viewed as higher or lower priorities across the group.

Figure 100. CBI Rating Importance



The chart above summarizes the average ranking scores for each proposed outcome area.

The results indicated that respondents generally viewed all five outcome areas as important, with all average scores falling above the midpoint of the scale. However, several categories emerged as stronger priorities.

Economic impacts and resilience/reliability received the highest average scores, both averaging approximately 4.0 out of 5.0. This suggests respondents place importance on affordability,

economic stability, reliable electric service and system resilience when considering community benefits.

Health and wellbeing ranked high with an average score slightly below 4.0 at 3.9. This indicated respondents view health, safety, and broader quality-of-life impacts as important considerations within long-term energy planning.

Energy equity and environmental outcomes received slightly lower average scores, though both remained above 3.0, indicating they are still viewed as priorities by respondents. The wider variation in these rankings may reflect differing perspectives among participants or uncertainty about how these categories are defined within the current framework.

In addition, CBIAG members were asked to consider how community benefit outcomes should be prioritized if tradeoffs are necessary and not all outcomes can be maximized at the same time. Respondents were asked to rank the five proposed outcome areas from highest priority to lowest priority.

A total of eight respondents completed the ranking exercise. Unlike the previous question, where respondents rated each category independently on a 1–5 importance scale, this question required respondents to prioritize outcomes relative to one another. This approach helped identify which outcomes members would elevate first when balancing competing priorities or constrained resources:

1. Economic impacts
2. Health & Wellbeing
3. Energy Equity
4. Resilience/Reliability
5. Environmental Impacts

Economic impacts emerged as the most frequently prioritized outcome overall. Multiple respondents ranked Economic Impacts as their top priority, indicating strong concern around affordability, economic opportunity, and the financial impacts of energy decisions on households and communities.

Health and wellbeing also ranked highly across responses and was frequently selected as either the first or second priority. This suggests respondents view broader community wellbeing, health, and quality-of-life impacts as central considerations within long-term energy planning.

Energy equity generally ranked in the middle of responses. While respondents consistently identified equity as important, rankings suggest it was more often viewed as a supporting or interconnected consideration rather than the highest standalone priority when tradeoffs were introduced.

Similarly, resilience/reliability ranked in the middle-to-upper range across responses. Although respondents consistently emphasized the importance of reliability in other engagement activities, this exercise suggests some participants may view reliability outcomes as closely tied to or embedded within economic and health-related priorities.

Environmental was ranked as the lowest priority when respondents were required to make tradeoffs between categories. However, this result should not be interpreted to mean respondents viewed environmental considerations as unimportant. Rather, the rankings suggest respondents may prioritize more immediate customer and community impacts—such as affordability, economic stability, health and reliability.

C.1.8 Portland Community Resiliency Fair

C.1.8.1 What We Did

On May 30, 2026, PGE participated in the Portland Community Resiliency Fair hosted by CSN at David Douglas High School in East Portland. The free community event connected attendees with nonprofit organizations, utilities and service providers offering resources related to household and community resiliency. The fair drew 577 attendees and included 54 organizations and service providers.

Similar to previous CSN community event, PGE hosted a booth that provided attendees with several ways to learn about programs and resources. A customer service representative was available to answer billing questions, help eligible customers enroll in the IQBD program and demand response programs. The booth also included information about wildfire preparedness and Project Zero clean energy activity bags for youth.

A dedicated portion of the booth focused on long-term resource planning. PGE used an illustration comparing the traditional electric grid with the modern grid to help explain how the electric system is changing and which created dialogue about energy and resource planning.

C.1.8.2 What We Heard

Many attendees came to the fair to participate in PGE's Ride and Drive event, which provided opportunities to learn about and experience electric vehicles (EVs) and e-bikes. This created a natural connection to conversations at the long-term resource planning table. PGE used the modern grid illustration to explain how increasing EV adoption affects electricity demand and how some EVs may support two-way power flow between vehicles and the grid. These conversations also provided an opportunity to explain how PGE considers projected EV adoption and associated electricity needs when planning for future resources through the IRP.

The connection between the Ride and Drive event and the resource planning table helped make long-term planning concepts more tangible by linking them to technologies attendees were already exploring at the fair. Attendees also raised concerns about the cost of their energy bills, reinforcing affordability as a common theme heard across PGE's community engagement activities.

C.1.8.3 What We Learned

Survey Results

PGE received six responses to the long-term resource planning survey. Although the number of responses was limited, the results provided additional insight into how participants weighed competing energy priorities and were consistent with themes heard through other community engagement activities.

Affordability emerged as the clearest concern. Four of the six respondents ranked the cost of energy and monthly bills first, and all six placed it among their top four concerns. It also had the highest overall average ranking. When asked which priorities PGE should consider in long-term planning, five of the six respondents selected prioritizing affordable power bills, making it the most frequently selected priority.

Reliability and extreme weather also ranked prominently. All six respondents placed outages and reliability among their top three concerns, making reliability the most consistently high-ranking issue after affordability. Extreme weather, including heat, cold, and storms, was ranked among the top three concerns by four of the six respondents.

Clean energy presented a more nuanced finding. Three respondents selected increasing clean energy resources as a priority for PGE's long-term planning, making it the second-most frequently selected planning priority. However, the clean energy transition generally ranked lower when participants were asked about their concerns. This distinction suggests that respondents may support continued investment in clean energy while viewing affordability, reliability, and extreme weather as more immediate concerns.

Community benefits were selected as a planning priority by two respondents, while two selected consideration of power reliability and outage frequency and one selected improving grid resilience. Since respondents could select multiple priorities, the results show that participants did not necessarily view affordability, clean energy, reliability, resilience, and community benefits as competing or mutually exclusive goals.

C.1.9 Community workshop at Center 50+ Energy & Resource Fair in Salem

Building on a similar approach from the East County Community Resiliency Fair, PGE sponsored and participated in the Center 50+ Energy & Resource Fair in Salem on June 27, 2026. This was a free community event that brought together more than 30 local utilities and service providers and offered exhibits, hands-on activities and workshops focused on energy and community resources. This was a great partnership as the Center 50+ offers a variety of in-person and virtual classes, activities and services for older adults.

As part of the event, PGE facilitated a workshop titled "How PGE Plans for the Future" to provide attendees with an accessible introduction to long-term resource planning. The session was designed to explain how PGE plans to meet future electricity needs while balancing affordability, reliability and clean energy targets. The presentation began by explaining as a regulated electric utility, PGE is required to plan ahead through a structured, data-driven process. The IRP was introduced as one of the primary tools used to evaluate how the company can meet projected electricity demand over a 20-year horizon. Participants were told IRP is the long-term roadmap that identifies future energy needs and the optimal portfolio of resources that can best meet those future needs. The presentation emphasized that planning is a collaborative process involving multiple perspectives. It includes internal PGE teams across planning, operations, rates, regulatory affairs, and business strategy, as well as external input from the Oregon Public Utility Commission, environmental organizations, consumer advocates, and other interested parties. This helped reinforce that long-term planning reflects a range of inputs and priorities.

Participants learned that the IRP is the first step in a multi-stage process that includes resource procurement and regulatory review. This includes forecasting long-term energy needs and developing a near-term action plan, procuring resources, and then implementing investments and recovering costs through rates following regulatory approval. This framing helped connect long-term modeling to real-world customer bill impacts.

Participants were introduced to core planning concepts such as forecasting future electricity demand, evaluating system needs, and using scenario modeling to investigate uncertainties to understand how different resource combinations can balance cost, risk, and reliability. PGE also discussed how uncertainty, policy shifts, technology changes, resource availability, and load growth all influence planning decisions.

Participants were highly interested, allowing for much back and forth, discussion, Q&A and engagement in the content and PGE planning in general. The conversation concluded by grounding the purpose of planning in customer and community impact. Participants reflected on how long-term planning helps reduce surprises, support reliability, manage affordability pressures, and guide the transition toward cleaner energy resources, while ensuring the system continues to meet everyday needs.

In addition to the workshop, PGE hosted a booth that provided information about customer programs, including the IQBD program and demand response programs. The booth also featured an illustration comparing the traditional electric grid with the modern grid, which helped spark conversations with attendees about how the electric system is changing. These conversations created an additional opportunity to introduce energy and long-term resource planning outside of the formal workshop setting.

C.1.9.1 What We Heard

Throughout the discussion, participants were active and engaged by asking questions and sharing their perspectives. Overall, the feedback received was positive and participants demonstrated an understanding of the complex planning environment PGE faces. Many participants shared that resource planning was a topic they had not previously encountered and expressed appreciation for the opportunity to learn about it in a community setting. In Addition, HB 2021 emissions reduction targets were new information to attendees and learning about the rising costs of clean energy resources and the variability of some resources helped ground the discussion in the real-world considerations involved in planning and achieving policy mandates. Participants were direct and candid in raising concerns about affordability, underscoring how central cost pressures are to their day-to-day lived experiences. Reliability and clean energy were also identified as areas of interest.

A workshop participant later stopped by the PGE booth and shared positive feedback about the session, noting that the presenters were engaging and that they enjoyed the conversation and learned a lot from the workshop.

C.1.9.2 What We Learned

Eleven (11) participants attended the workshop, and one completed the voluntary survey. Based on the survey results, they viewed the workshop positively, agreeing that the session was a valuable use of their time. The most useful aspect was learning how the planning process informs reliability

needs and helps communities prepare for future power outages. When considering long-term planning priorities, the respondent emphasized increasing community benefits, expanding clean energy resources and improving grid resilience.

Affordability emerged as the respondent's top concern, with the cost of monthly energy bills ranked highest. Reliability and outages were also significant concerns, followed by the impacts of extreme weather events, including heat, cold, and storms. Wildfire impacts and proactive public safety power shutoffs were identified as additional concerns, while the clean energy transition ranked lower, though it remained relevant. Looking ahead, the respondent encouraged PGE to consider home solar as part of future planning efforts, indicating interest in distributed energy solutions that may support customer resilience.

The survey was offered digitally through a QR code, and the limited response highlighted an important lesson for future community engagement that relying solely on a digital survey may create barriers to participation. The digital divide remains a consideration, particularly when engaging older adults and other community members who may have varying levels of access to or comfort with technology. Future engagement efforts will include both digital and paper survey options to provide more accessible ways for participants to share feedback and potentially increase participation.

C.1.10 Additional Learning Opportunity: Tour of PGE's Integrated Operations Center with CBIAG Members—From Planning to Operations

On June 3, 2026 CBIAG members participated in our annual closed work session at PGE's Integrated Operations Center (IOC). During the visit, members took part in a facility tour that provided a firsthand look at how the electric grid operates, including how operators monitor system conditions, maintain reliability and balance supply and demand through the energy trading market.

The experience built directly on discussions from the January meeting about the IRP and CEP. Members were able to connect long-term planning concepts they learned earlier in the year with the day-to-day operational activities they observed at the IOC. Seeing systems and processes in action deepened their understanding of how resource planning, grid reliability and energy markets work together to serve customers and support Oregon's clean energy future.

The tour was widely viewed as a valuable and enriching experience. As one member shared, "I found the tour of the facility absolutely fascinating." The visit provided a unique opportunity to strengthen their understanding of the complex work required to deliver electricity to customers every day.

C.1.11 Cross-engagement on Long-term Planning Insights

Feedback gathered from the CBIAG discussions, community activities, and surveys revealed several consistent themes such as, affordability, balancing objectives and decision-making and how they relate to customer impact. While each engagement activity involved different audiences and participation levels, the results collectively provide insights into how customers and community members interpret the CEP/IRP and what priorities they believe should guide long-term planning decisions.

C.1.12 Affordability

Affordability consistently emerged as the most prominent concern across all engagement activities.

CBIAG members raised affordability considerations directly during the meeting discussion and through survey responses, where the cost of energy and monthly bills was most frequently ranked as the top concern. Similar patterns were observed in the workshop survey and the booth survey, where prioritizing affordable power bills was the most frequently selected long-term planning priority. Together, the findings indicate that customers and CBIAG members consistently view affordability as a primary lens through which long-term planning decisions are evaluated.

C.1.13 Balancing Objectives

PGE's engagement activities demonstrated that on a high-level, participants prioritized affordability as well as clean energy. Responses suggest that community members learned that long-term planning has to balance multiple objectives. The CBIAG survey, workshop survey, and booth survey, respondents selected priorities that included affordable power bills, increasing clean energy resources and improving system resilience. The responses indicate participants support progress toward clean energy while maintaining reliable service and manageable costs for customers.

C.1.14 Decision-making

Participants expressed an interest in understanding how PGE makes decisions. During both the CBIAG meeting and the community workshop, many questions focused on the structure of the outcomes of a planning process, rather than how assumptions are developed or how modeling informs resource portfolio options. They were also interested in how regulatory oversight functions and how community input is considered. Workshop participants indicated learning what long-term planning is in the context of how real-world decisions are developed was a useful part of the session but were most interested in how future decisions might impact them, specifically their bills.

C.1.15 Theme

Across all engagement approaches, a clear and consistent theme emerged: participants were most interested in customer impacts, particularly affordability, bill impacts, and access to customer programs, rather than the technical details or purpose of long-term planning. The CBIAG meetings provided a structured forum for deeper discussion, while the community workshop offered a classroom-style setting that was open to the public, with incentives supporting participation and creating a more focused learning environment. In contrast, informational tables and the booth survey at the resiliency fair enabled PGE to connect with a broader, more varied audience in a more informal setting. Together, these approaches expanded awareness of the IRP and CEP while elevating community perspectives on how planning relates (or does not relate) to customer experience and cost.

C.1.16 Conclusion

The engagement activities described here reflect PGE's evolving efforts to broaden understanding and potential participation in the 2026 IRP and CEP process by creating additional opportunities for learning, dialogue, and feedback beyond the technical roundtable forums. Throughout these engagements, PGE recognized that technical planning topics can be difficult to translate for

broader audiences and intentionally used different formats and levels of detail to support understanding across varying levels of familiarity.

Through CBIAG discussions, community workshops and public outreach at the community events, PGE introduced foundational long-term planning concepts and CBIs, in multiple settings designed to support a broader understanding of the resource planning process, how community impacts are considered, and where long-term planning fits within other PGE activities and decisions.

Across these engagements, consistent themes emerged. Affordability remained a primary focus, with participants raising questions about energy costs, monthly bills, and the potential impacts of company decisions on customers. Reliability, resiliency, and clean energy development were also frequently discussed as interconnected priorities along with affordability. Participants also expressed interest in CBIs and how community benefits are defined, measured, and incorporated into planning, along with broader questions about how decisions are made, how tradeoffs are evaluated, and how community perspectives are reflected.

These engagement efforts highlight the value of using multiple approaches to reach different audiences, with structured CBIAG discussions supporting deeper technical dialogue and community outreach providing more accessible and informal opportunities for participation. Together, they helped surface customer priorities while reinforcing the challenge of making complex technical topics both understandable and relevant.

These activities provide a foundation for ongoing engagement, especially with the CBIAG. The questions and perspectives shared will continue to inform how PGE approaches transparency and participation, including the ongoing need to ensure that complex technical topics are communicated in ways that remain relevant, accessible, and meaningful. PGE also learned the importance of continuing to find ways to bring interested parties and EJ communities along on topics and in forums where their interests and concerns are most readily addressed, which may not be in IRP modeling and long-term planning.

C.2 Technical Roundtables and Stakeholder Feedback

PGE manages CEP and IRP development through a collaborative, interactive process with an active public stakeholder group in a public meeting every four to six weeks. PGE's first roundtable for the 2026 CEP/IRP process was held in September 2025, with PGE hosting 10 meetings over 12 months through August 2026. All IRP meetings are open to the public and are generally hosted once a month. These roundtable meetings are technical forums to communicate, educate and seek feedback regarding PGE's IRP methodology, analysis and results. The IRP content presented during roundtables is complex, often requiring experience and knowledge of the energy industry. PGE notes the content complexity at roundtables and seeks to educate and engage novice and experienced utility stakeholders on the content in accessible, understandable, and engaging ways because stakeholders represent diverse perspectives and expertise. Roundtable participants include OPUC Staff, educational institutions, developers, and other interested participants.

PGE subject matter experts seek to present comprehensive information in an approachable structure to encourage feedback and requests for clarification. As topics and attendance change, and in response to stakeholder feedback, PGE has adjusted how and when we take feedback

during roundtable meetings. To provide transparency to the public, PGE publishes direct questions including PGE's responses to each question, as permission allows, in monthly updates to materials made publicly available on PGE's website. This allows all stakeholders to benefit from questions that other groups bring and provides a clear record of the nature and timing of the feedback received, and PGE's determination of if, how and if not, why not, to incorporate into CEP/IRP analysis.

Through the roundtable process, PGE was responsive to stakeholders by:

- Sharing draft information as the analysis unfolded.
- Inviting stakeholders to submit informal comments throughout the filing process.
- Posted video archives of each meeting and the meeting presentation on our website.
- Publishing comments received via the feedback form, starting in September 2025, and responses each month to allow all participants to benefit from what others are asking about. Many, but not all, roundtables received stakeholder comments.
- Experimenting with different approaches to facilitating the roundtables to encourage equitable participation among stakeholders, including using the chat function, unmuting to ask questions, using the raise hand function, etc.

The comments and suggestions shared with us are incorporated into our data analysis and, modeling in our final IRP, and the comments we received, along with responses, are posted to PGE's IRP webpage. PGE roundtables covered a wide range of topics including information about PGE's planning landscape, details of PGE's modeling methodology, PGE's input assumptions, incorporation and refinement of community benefit and near-term cost metrics, and public presentation of drafts for key CEP/IRP sections. Feedback ranged across these topics, with particular attention to the following topics:

- Transmission constraints and incorporation into planning
- Characterization of and modeling results regarding PGE's Virtual Power Plant
- Expected pace of clean energy procurement
- Community Benefit Indicators (CBIs), including resource CBIs (rCBIs)
- Portfolio analysis, scoring and results

The following subsections list and provide website links to materials shared, meeting recordings, and where applicable, PGE's responses to stakeholder questions, for each roundtable.

C.2.1 September 3, 2025 CEP/IRP Roundtable 25-6

- Agenda
- IRP 101 video, pdf
- 2026 CEP/IRP Analysis Refinements video, pdf
- 2026 CEP/IRP Timeline & Q&A video, pdf
- Closing Remarks | Next Steps

C.2.2 Oct. 22, 2025 CEP/IRP Roundtable 25-7

- Agenda
- Corporate Load Forecast - Methodology & Trends video, pdf
- Draft AdopDER Forecast video, pdf
- Existing Resources & Resource Topology video, pdf
- Futures/ Markets video, pdf Closing Remarks | Next Steps
- Stakeholder Feedback & PGE Responses

C.2.3 Dec. 10, 2025 CEP/IRP Roundtable 25-8

- Agenda
- Supply-Side Resource Options video, pdf video, pdf
- Capacity Need & Its Drivers video, pdf
- Transmission Options video, pdf
- Role of VPP in the IRP video, pdf
- EE Integration into IRP video, pdf Closing Remarks | Next Steps
- Stakeholder Feedback and PGE Responses

C.2.4 Jan. 14, 2026 CEP/IRP Roundtable 26-1

- Agenda
- PGE Longer Term Local Transmission Plan for 2024-2025 Planning Cycle video, pdf
- Resource Contract Extension - Update video, pdf
- Flexibility study - Overview video, pdf
- Clean Energy Plan – Overview video, pdf
- Community Benefit Indicators video, pdf
- PGE'S Community Engagement Approach for 2026 CEP video, pdf
- Portfolio/Scenarios - Designs video, pdf
- Closing Remarks | Next Steps
- Stakeholder Feedback & PGE Responses

C.2.5 Feb. 24, 2026 CEP/IRP Roundtable 26-2

- Agenda
- PGE Announcement To Acquire WA Utility video, ppt
- Clean Energy Plan & Integrated Resource Plan Community Engagement Updates video, ppt
- Flexibility Study Draft Results video, ppt

- CBRE Update video, ppt
- IRP Emissions Forecasting video, ppt
- Diverse Market Transmission Framework video, ppt
- Portfolio Scoring video, ppt
- ELCCs video, ppt
- RFP Update and Proxy video, ppt
- Closing Remarks | Next Steps
- Stakeholder Feedback & PGE Responses

C.2.6 Apr. 8, 2026 CEP/IRP Roundtable 26-3

- Agenda
- Community Engagement video, pdf
- Transmission Constraints: Methodology & Approach video, pdf
- Price Futures Update video, pdf
- Energy Values for Resources video, pdf
- Generic Resource Cost Update video, pdf
- Market Emission Factor Scenarios video, pdf
- Next Steps and Close
- Stakeholder Feedback & PGE Responses

C.2.7 May 20, 2026 CEP/IRP Roundtable 26-4

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- Stakeholder Feedback Responses video, pdf
- Community Benefit Indicators (CBIs) video, pdf
- Portfolio Analysis Scenarios video, pdf
- Cost Cap Scenario Update video, pdf
- Transmission Constraints Results and Analysis video, pdf
- VPP Integration & ELCC Review video, pdf
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- Community Impacts Metrics video, pdf

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Appendix D Community Benefits Indicators

D.1 Background

PGE continues to evolve and advance the integration of community benefits indicators (CBIs) into resource planning processes, consistent with regulatory directives and community stakeholder priorities. This appendix focuses on the approaches deployed for this CEP/IRP, which have continued to evolve since the 2023 CEP/IRP and Update filed in 2025. As guided by OPUC Order No. 22-390, continuous stakeholder input since the passage of HB 2021, and most recently, modified IRP/CEP rules in OAR Chapter 860, Division 90 adopted in 2026, PGE has continued to expand its CBI framework to encompass measurable and impactful metrics across the five categories identified by OPUC in Order No. 22-390:

1. Economic impacts: economic development, increased access to jobs, economic well-being, productivity.
2. Energy equity: Improved awareness and access to clean energy programs by environmental justice and tribal communities; increased affordability, increased efficiency of housing stock, reduced arrearages and disconnections.
3. Health & community well-being: Increased comfort; improved public health outcomes, particularly for environmental justice communities; reduced local emissions; improved home health and safety (indoor air quality, etc.).
4. Resilience & reliability: Improved grid resilience, increased resiliency and reliability in environmental justice communities, including reduced recovery time and frequency of outages.
5. Environmental impacts: Reduced air emissions, including CO2 and criteria pollutants.

The Order put forward a CBI framework that included at least one metric of each of three interim CBI types. In 2023, PGE filed its first CEP as part of the IRP, including a set of CBIs and metrics responsive to the three CBI types of portfolio CBIs (pCBIs), resource CBIs (rCBIs), and informational CBIs (iCBIs), which continue to guide PGE's current approach.

In April 2024, OPUC issued Order No. 24-096 (in LC 80), which identified the following required actions:

- "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."

In 2024, PGE engaged Cadeo (now Resource Innovations) to conduct research on CBIs. Based on this research and as further informed by the CBIAG and stakeholder feedback, PGE refined its approach to CBIs, ultimately landing on a list of 30 CBIs developed by Cadeo (including two in-

depth review sessions with the CBIAG), shown in Figure 101, characterized by their applicability to specific resources, monetizable value, and alignment across OPUC categories.[140]

Figure 101. List of CBIs by OPUC Category and Type

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

By OPUC Category

- Economic Impacts
- Environmental
- Energy Equity
- Resiliency/Reliability
- Health + Community Wellbeing

By CBI Type

- Portfolio CBIs (pCBIs)
- Resource CBIs (rCBIs)
- Informational CBIs (iCBIs)

Following CBI discussions and direction from UM 2225 and LC 80, PGE utilized the above as well as the same structured pathways (for each pCBIs, rCBIs, and iCBIs) to integrate CBIs into the 2023 CEP/IRP Update processes in 2025.[141]

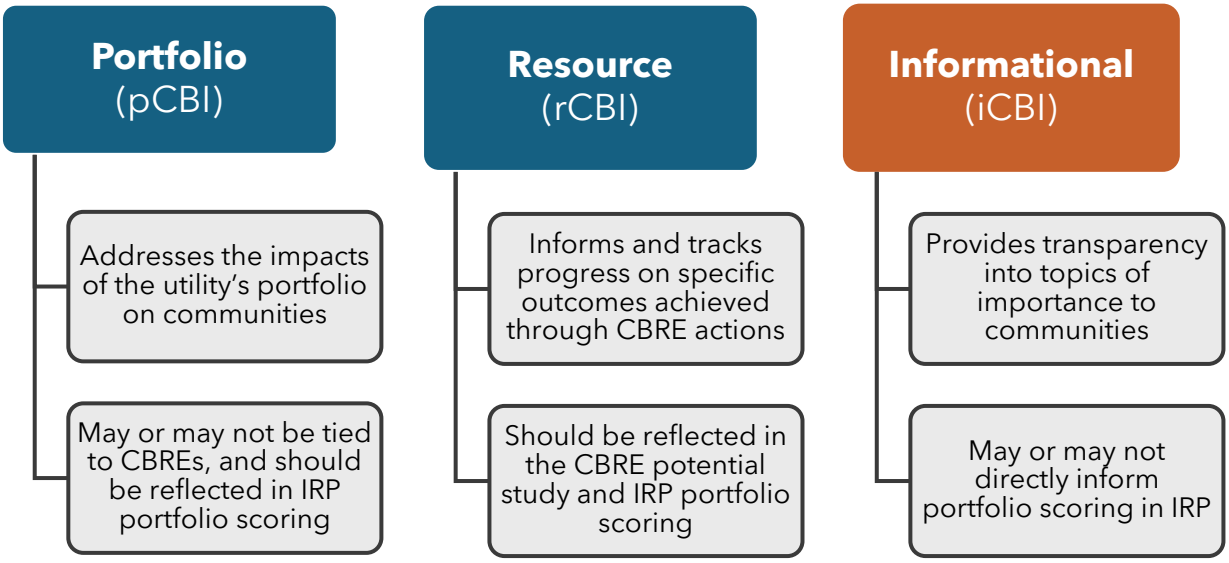
Now, after further internal review to evolve the work, as well as informed by the new IRP/CEP rules adopted in 2026[142] and ongoing CBIAG and stakeholder engagements,[143] PGE has further advanced its approach to CBIs in this planning cycle.

D.1.1 Continuing to Advance CBIs in Planning

PGE continues to lean on initial direction from UM 2225 to inform how to incorporate CBIs in planning, as summarized in Figure 102, and revisited with stakeholders first during this planning cycle at the January 2026 roundtable.[144]

[140] For more information on how Cadeo developed the list of CBIs currently used, see PGE 2023 CEP/IRP Update, Appendix G.
[141] For more information on the past analytical approach, see PGE 2023 CEP/IRP Update, Chapter 5.5.
[142] OAR Chapter 860, Division 90.
[143] CEP/IRP Roundtables | PGE
[144] Integrated Resource Planning Roundtable Presentation

Figure 102. PGE's approach to CBIs in Planning



* Analyzed in forward-looking CEP/IRP modeling analysis
* Reported out in measured values for previous years

The methodologies and details within each of the three CBI structured pathways have evolved since the first CEP to align with current rules and portfolio analysis methodologies, the 30 CBIs developed by Cadeo shown in Figure B9.1a, and as informed by stakeholder and environmental justice community feedback. In April 2026, PGE reintroduced the CBI framework to the CBIAG to reinforce its purpose and connection to long-term planning.[145] Interest in this topic and how to participate in its evolution continued to be key to the CBIAG, as the group also highlighted affordability as central to community priorities. CBIAG members also expressed understanding that CBIs are a complex topic with difficulties in balancing real-world priorities with including meaningful metrics in modeling and planning. As indicated in Appendix Section D.3 and Appendix Section G.3, the CBIAG also played an important role in reviewing real CBRE project proposals for community benefits. This further raises the importance of recognizing the distinction between specifying and reporting quantifiable community benefit indicators on a planning-basis here, as compared to how this may or may not align with top real-world priorities when it comes to community needs and interests, as reflected in an individual project under consideration at a given time.

- PGE used these early 2026 engagements and the new CEP/IRP rules to inform the evolving approach to community impact metrics in this planning cycle. This iterative advancement of CBIs and a high-level overview of the quantification strategy for this CEP/IRP were first

[145] Appendix Section C.1.7.

presented at the May 2026 roundtable,[146] with more detail and draft metrics and analysis results presented at the June and August 2026 roundtables.[147] [148]

- For this CEP/IRP, PGE included the three CBI structured pathways, as summarized below:
- Portfolio CBIs (pCBI): calculated to represent aggregated community impacts of the resource selections within a portfolio, allowing portfolio analysis results to better reflect the community benefit value associated with modeled resource selections. See Appendix Section D.2 for more detail.
- Resource CBIs (rCBI): assumed to lower costs for the CBRE proxy new resource option to enhance cost-competitiveness and encourage selection in portfolio analysis optimization. See Appendix Section D.3 for more detail.
- Informational CBIs (iCBI): three years of historical metrics mapped to the 30 CBIs discussed above. These provide a snapshot of PGE's progress over time on tracking and reporting metrics representative of community benefits See Appendix Section D.4 for more detail.

A fourth use case of CBIs—screening real project or program proposals—falls largely beyond the scope of planning and the CEP/IRP. PGE's efforts to develop CBIs via a planning framework may inform but is not intended to limit community benefits that PGE may seek to advance via specific projects or programs, for example individual CBRE deployment or customer programs.

The following sections describe in detail PGE's current CBI framework for planning and methodologies as advanced in this planning cycle and in response to the new CEP/IRP rules. CEP/IRP modeling includes forward-looking analysis for pCBIs and rCBIs;[149] while new historical look-back metrics enable tracking for iCBIs;[150] with all data, metrics, analysis results, and information broadly informative to PGE planning and decision-making,[151] as further described below.

D.2 Portfolio CBIs

Portfolio CBIs, or pCBIs, aim to address the impacts of the utility's portfolio on communities, and are reflected in IRP portfolio scoring. PGE's approach aims to 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). Similar to the approach in the 2023 CEP/IRP Update, PGE assigned benefits to resource types across the five top-level categories laid out in OPUC guidance. PGE applied pCBIs as proxy values at the back end of IRP modeling to characterize and identify resource types that likely accrue CBI benefits in applicable categories. PGE then considers these results as part of the scoring for portfolio selection.

PGE defines a portfolio as a fixed set of resource decisions for a given scenario. The capacity expansion model, ROSE-E, selects the optimal set of incremental resource additions given the parameters of a scenario. For example, all resource buildouts are designed to meet reliability

[146] Appendix Section C.2.7.
[147] Appendix Sections C.2.8, C.2.10.
[148] OAR 860-90-0070(1)(c).
[149] OAR 860-90-0060(7)(g)(E)
[150] OAR 860-90-0100(5).
[151] OAR 860-90-0100(4)(c).

needs, with additional scenarios analyzing pathways to compliance with HB 2021. Resources are included within the IRP process under consultation with stakeholders so that the most representative set of potential resource options are available for the model's selection. While cost and risk have traditionally been included in portfolio analysis, PGE now also includes pCBIs to incorporate community benefits and their value in portfolio scoring.

Portfolio CBIs are operationalized in this planning cycle as being assigned to each relevant proxy new resource option across the five top-level categories, if relevant to that resource. Portfolio benefits are: 1 MW of the new resource added equals 1 unit of community benefit, for each top-level category that applies, as summarized in Table 46.

Table 46. pCBIs Quantified in Portfolio Analysis

Resource	Economic Impacts*	Energy Equity	Health & Community	Resilience & Reliability	Environ. Impacts
Storage (4; 6; 100; PHS)	x			x	x
Utility-Scale Standalone Solar	x				x
Utility-Scale Standalone Wind	x				x
Hybrid Solar	x			x	x
Hybrid Wind	x			x	x
Energy Efficiency (NCE EE)	x	x	x	x	x
Virtual Power Plant (VPP)	x	x	x	x	x
CBRE	x	x	x	x	x
SSR	x	x		x	x
Natural Gas	x			x	
Transmission	x			x	

Due to the complexity of attributing specific 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,[152] a resource type assigned a pCBI for a given category broadly captures the following:

- Economic impacts: include economic development, increased access to jobs, economic well-being, increased property value, and increased productivity, relevant to a wide range of resource types, including supply-side resources, as potential economic development and job creation opportunities.
- Energy equity: Benefits such as improved affordability and reduced arrearages (i.e., time-of-use rates), applicable to resource types that may further be targeted for disadvantaged

[152] This approach is 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.

communities and have the highest likelihood of yielding real bill savings (to represent benefits beyond what is reflected within the IRP modeling framework).

- Health & community well-being: proxy representation of improved indoor air quality and household safety through weatherization and HVAC measures as well as community-based renewables.
- Resilience & reliability: Benefits such as reduced risk of, or frequency and duration of, outages across communities and improved grid resiliency.
- Environmental impacts: Proxy GHG and other air pollutant emissions reductions to account for the resource's role in mitigating climate change and other environmental impacts.

Similar to quantification in the 2023 CEP/IRP Update, pCBIs are determined by the quantities of resources selected in portfolio analysis. In this CEP/IRP, the metrics reflect portfolio benefits in each of the five categories associated with new resource additions, allowing capacity expansion results to reflect a community benefit value associated with modeled resource selections. See Table 26 for report-out of pCBI results by category for each scenario analyzed in this CEP/IRP.

Portfolios with higher pCBI values could be identified as higher performing in portfolio analysis (solely based on this valuing). It is important to keep in mind the limitations of these metrics. They are distinct from other "least-cost, least-risk" data-based analysis and provide a different representation of community impacts to enable inclusion in modeling-based planning but may not directly align with meaningful real-world community values.

Further, 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 example, CBIs unlocked through energy efficiency often relate to specific measures, such as weatherization or HVAC improvements. When IRP representation as EE or VPP 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.

While this approach includes assumptions and methodologies that may continue to evolve, these results are directionally helpful for understanding which portfolios are adding resources with potentially greater community benefit than others. It is important to consider these metrics in tandem with all other resource planning analysis results. As a result, pCBI metrics are included in Portfolio Scoring, further discussed in Chapter 7, along with other key scoring metrics, as a part of informing complex decision-making that ultimately must balance community interests with affordability, reliability, clean energy, and other key objectives.[153]

[153] OAR 860-90-0060(7)(g)(E) and OAR 860-90-0100(4).

D.3 Resource CBIs

Resource CBIs, or rCBIs, inform actions and potential next steps relating to CBREs. For this planning cycle, this is most directly informed by the CBRE RFO, conducted separate from the CEP/IRP, described in Section 6.3.4, as well as informed by portfolio analysis within the IRP modeling framework.

In the previous iteration of rCBI analysis in CEP/IRP, a direct percentage adjustment was applied to reduce the levelized cost of select energy resources (energy efficiency, demand response, and CBREs) to account for estimated participant/community benefits, informed by secondary research. Due to limited primary research on benefit valuation for specific resource types within PGE jurisdiction, the analysis relied on secondary sources and adapted benefit metrics for IRP application.[154]

For this planning cycle, the rCBI approach has been advanced based on evolved understandings, planning methodology changes, and through the availability of actual market data (i.e., as collected through the CBRE RFO process). The revised rCBI analysis can be used to provide insight into two distinct questions:

1. What cost would a CBRE project need to be competitive compared to other options?
2. What funding sources or quantifiable benefits could be used to close the gap to support acquisition of resources deemed beneficial to communities?

In the 2023 CEP/IRP Update, energy efficiency was included in rCBI analysis. However, PGE's current understanding of the ETO analysis and data used is that EE costs are already inclusive of non-energy benefits (such as accounting for comfort through shell and HVAC related-measures). Further monetization through rCBI analysis could result in double-counting or over-stating benefits, thus PGE has elected to exclude rCBI analysis for EE in this CEP/IRP.

Similarly, the 2023 CEP/IRP Update included demand response in rCBI analysis, but PGE is electing to also exclude in this CEP/IRP due to the advancements of DR and VPP bin representation in the modeling, which are further discussed in Section 7.10. The only property value non-energy benefit applicable within the new VPP framework is associated with the residential battery program and was deemed too small to meaningfully reduce VPP cost assumptions, thus it has not been included in rCBI analysis.

PGE is focusing rCBI analysis on the energy resource of CBREs only. See Appendix Section G.3 for more description of this proxy resource option in planning and the CBRE RFO that informed it. Broadly, the RFO provided important market insight to advance PGE's community-focused work, offering both market intelligence on the nature of the community benefits offered by project developers and valued by CBIAG members, and a benchmark estimate of CBRE incremental additional procurement costs. PGE compared relative procurement costs of CBRE projects against comparable utility-scale resources in the February and May 2026 Roundtables,[155] finding the projects from the RFO to be roughly 30-60% more costly than proxy utility-scale standalone solar

[154] PGE 2023 CEP/IRP Update, Chapter 5.5.2.2 Integrating CBIs into IRP Modeling.
[155] Appendix C.2.5 and Appendix C.2.7.

and solar plus storage options. The proxy CBRE resource included in portfolio analysis is reflective of a microgrid resource of solar plus storage; informed by RFO bid results, and because these types of projects would better support resilience than other resource types. While PGE has defined the CBRE proxy resource in this IRP as a 20 MW hybrid, the rCBI framework could conceptually be extended to other types of CBRE such as alternative technologies, configurations, or project sizes.

Due to the interest in CBREs and the RFO's higher cost findings, PGE's approach in this CEP/IRP incorporated resource CBIs, or rCBIs, in all portfolio analysis and scenarios through the assumed cost of the proxy CBRE resource option. This assumption was used in planning to understand how different CBRE cost assumptions might result in greater deployment of these kinds of projects in portfolio analysis. Changes to the cost assumptions, namely reducing the market-informed proxy CBRE cost for modeling by assuming some quantity of rCBIs, highlights that on average, actual bid costs need to come down to make these kinds of projects more competitive compared to other procurement options. The downward adjustment to levelized costs for proxy CBREs in all scenarios begins in 2032 by assuming a value of rCBIs that brings the cost (originally informed by RFO bid data) down to a level similar to utility-scale standalone solar. In the modeling, this encouraged greater selection of the proxy CBRE resource in portfolio analysis after the costs came down. See Chapter 7 for more on CBRE selection in modeling results.

Figure 103 shows the rCBI values assumed, lowering the costs for a proxy CBRE by roughly half. In the first five years of the planning horizon, PGE's cost assumptions align with average pricing informed by the first three rounds of the ongoing CBRE RFO. PGE expects that completion of commercial actions, interconnection studies, and construction and energization timelines will likely result in availability of those projects in 2029-2031. See Appendix Section G.3 for more detail on the CBRE resource availability assumptions for IRP. For modeling purposes, PGE linked application of the rCBI to a next phase of projects, with assumed availability beginning in 2032. This timing assumption accounts for the time required for development of new programs or alignment with non-utility funding streams plus project development timelines. This assumption is not intended to suggest that rCBIs could not be applied earlier to eligible projects. See Section 7.9 for more on the rCBI application and Section 2.2.3 for more on PGE's near-term CBRE-related actions.

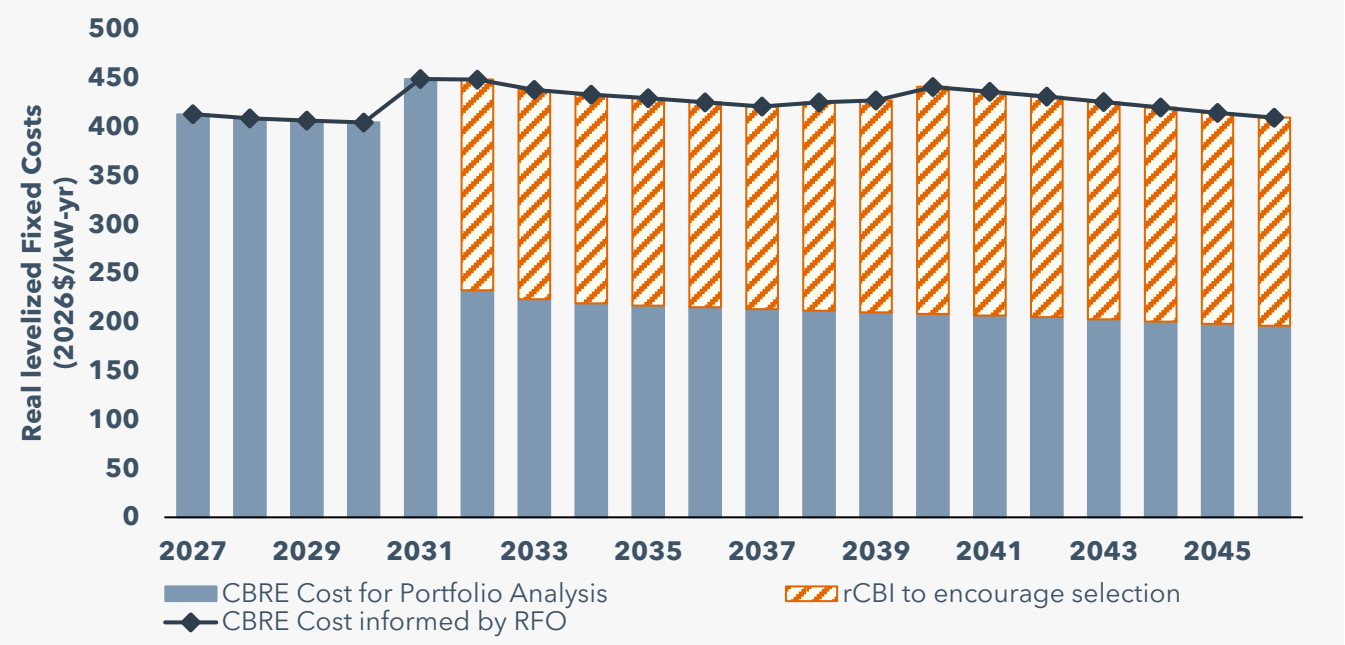
PGE recognizes the potential for CBREs to provide enhanced value to communities. The proxy CBRE cost assumptions in this CEP/IRP, which were informed by the RFO, are higher than those of proxy utility-scale resource options. PGE's analysis, utilizing the rCBI approach, is intended to reflect the potential for grant funding or other opportunities to subsidize the costs of these projects, making them more competitive in resource optimization analysis. The cost adjustment could also be thought of as representing monetization of community benefits such as economic and health benefits of local solar panels, increased property value relevant to behind the meter projects, and/or increased resiliency against outages with localized power sources. Either benefit assumption—grant funding available or monetization of local benefits for individual projects—are not modeled directly within the IRP framework, therefore this rCBI approach allows these kinds of options to be considered in a high-level way to help shape the understanding of CBRE viability compared to other potentially more cost-competitive options.

While CBREs may have the potential to provide benefits to communities, these benefits are difficult to monetize and accrue throughout the resource planning process. PGE remains committed to

continuing work with communities and stakeholders to further refine this framework through planning, acquisition, and other efforts.

For the 2026 CEP/IRP, this rCBI adjustment approach to CBRE costs is incorporated into resource cost comparisons within the capacity expansion modeling. This adjustment informs the cost-minimization portfolio analysis to influence which resources are selected towards the selection of CBREs after 2032, representing resource selection that may increase certain community benefit. This approach highlights that the costs for CBREs may need to come down in order to encourage higher volumes of CBRE build-out compared to other, currently, more cost-effective resource options in IRP analysis. See Section 7.9 for more on the results and findings of how portfolio analysis with and without rCBIs impacts CBRE selection in the modeling.

Figure 103. CBRE Reference Case Cost Adjustment for rCBIs



PGE also analyzed the HB 2021 Preferred Portfolio with proxy CBRE cost assumptions excluding the rCBI benefit to investigate whether and how CBREs are selected in portfolio analysis when costs are more similar to the RFO average bid data findings. See Section 7.9 for rCBI sensitivity analysis findings in this CEP/IRP. The evolution during this planning cycle of the CBRE RFO and rCBI results in IRP are distinct from other IRP scoring metrics and are practically informative to utility implementation decisions, especially relating to investigation of CBREs and their potential future deployment; see Section 2.2.3 for more on CBRE-related near-term actions.

D.4 Informational CBIs

Informational CBIs may be used now and in the future as tracking tools to monitor outcomes over time. They may also support the tracking of a variety of long-term impacts, ranging from low-income household benefits, to increased community resiliency, to job creation, and more. For this CEP/IRP, informational CBIs, or iCBIs, now include more historical data to advance CBI work, provide more

transparency into a range of topics identified as important for communities, and centralize a set of values in a single report that PGE can update in future planning cycles. This approach is directly informed by Order 24-096 guidance to develop informational-only metrics and to new rule OAR 860-90-0100(5), which requires CEPs to include measured values for all CBIs defined in the CEP.[156]

Table 47 reports out iCBI measured values for the past three years, as available. PGE has identified 21 metrics for report-out based on their applicability to the existing list of 30 CBIs, and how well the data characterized the CBI, based on descriptions from the 2024 CADEO report.[157] With this being the first time PGE is reporting historical measured values in relation to CBIs, PGE primarily relied on existing data collection and metrics integrated into PGE business operations. Much of the metrics come from publicly available data sources with established methodologies, data collection procedures, and robust use cases of the metrics reported such as:

- Federal reporting, such as through the Securities and Exchange Commission (SEC) 10-K, Alternative Fuels Datacenter (AFDC), and Energy Information Administration (EIA);
- State reporting, such as through OPUC reports and filings and ODEQ emissions reporting; and
- PGE reports, such as sustainability reports (SR) and Transportation Electrification (TE) plans.

Some iCBI metrics reported are applicable to more than one CBI. For example, local air pollutant emissions tracking is relevant for Environmental Impacts as well as Health & Community Wellbeing CBIs. The most relevant CBIs for a given iCBI metric in Table 47 are noted in the "CBI #" column. Further reading in any report noted in the "Key Data Source" column of the table will provide more context around both the metric included, as well as additional activities PGE undertakes in relation to that topic.

[156] OAR 860-90-0060(7)(g)(E) and OAR 860-90-0100(4).
[157] PGE September 4, 2024 Roundtable, https://assets.ctfassets.net/416ywc1laqmd/2KYZToHzDEUncfQrvJfCNS/f6c4eeef494dcfc85975515f53d1ea5a/IRP_Roundtable_September_24-5.pdf#page=44

Table 47. Historical measured values of iCBIs

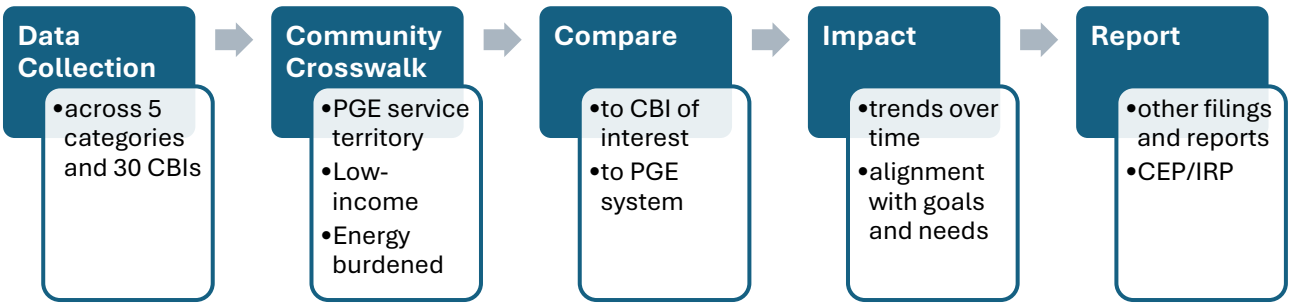
Metric ID	Metric	CBI Category	CBI #	2023	2024	2025	Unit	Key Data Source
i1	Public charging stations in PGE service territory	Econ. Impacts; Energy Equity	1, 3	370	530	766	Count	AFDC, TE Plan
i2	Public charging ports in PGE service territory: Total (DCFC)	Econ. Impacts; Energy Equity	1, 3	1,001 (240)	1,341 (304)	1,813 (370)	Count	AFDC, TE Plan
i3	Generating capacity owned and contracted by PGE	Econ. Impacts	6	3,359	3,573	3,586	MW	10-K
i4	Customers participating in voluntary programs to shift energy use	Energy Equity	10	22%	24%	29%	Percent	SR
i5	Number of customers participating in IQBD	Energy Equity	10	69,006	89,500	105,156	Count	IQBD Program, Energy Burden Metrics Reporting
i6	Income-qualified bill discount credits provided to customers	Energy Equity	4, 16	$18.25	$40.91	$56.96	$Million	IQBD Program, Energy Burden Metrics Reporting
i7	Community Engagements: activities, events, learning labs, meetings	Energy Equity	11	110	287	290	Count	Community Engagements
i8	Annual average residential customers in arrears	Energy Equity	17	120,042	123,556	131,271	Count	Energy Burden Metrics Reporting
i9	Residential customer electricity disconnections for non-payment	Energy Equity	18	29,584	35,324	33,757	Count	Energy Burden Metrics Reporting
i10	Community Solar capacity online in year	Energy Equity	9, 14	2.0	9.8	14.7	MW	SR, active generators, IRP
i11	New utility-scale wind, solar, storage capacity online in year	Energy Equity	9, 13, 14	0	786	0	MW	SR, active generators, IRP

Metric ID	Metric	CBI Category	CBI #	2023	2024	2025	Unit	Key Data Source
i12	Annual investment in electric energy efficiency programs	Energy Equity; Health&Comm	15, 20	$87.83	$130.45	$141.22	$Million	SR
i13	Incremental annual electricity savings from energy efficiency measures	Energy Equity; Health&Comm	15, 20	223,655	250,850	213,006	MWh	SR
i14	Potential peak demand savings (demand response capacity)	Resil. & Reliab.	25, 26, 29	146.2	157.4	171.45	MW	EIA Form 861
i15	Outages: System Average Interruption Frequency Index (SAIFI)	Resil. & Reliab.	5, 27, 28, 29	0.65	1.27	0.89	Events	SR, Annual Reliability Report
i16	Outages: System Average Interruption Duration Index (SAIDI)	Resil. & Reliab.	5, 27, 28, 29	109	772	273	Minutes	SR, Annual Reliability Report
i17	Total capital expenditures	Resil. & Reliab.	25	$1,462	$1,262	$1,143	$Million	10-K
i18	Anthropogenic GHG Emissions of total owned and purchased generation for retail	Env. Impacts; Health&Comm.	8, 21, 22, 23	6,559,734	6,078,895	6,084,099	MT CO2e	SR, ODEQ reports
i19	Nitrogen Oxide (NOx) Emissions of service to retail and outside PGE territory	Health&Comm.	21, 22, 23	2,787	2,495	2,149	MT NOx	SR, ODEQ reports
i20	Sulfur Dioxide (SO2) Emissions of service to retail and outside PGE territory	Health&Comm.	21, 22, 23	953	853	876	MT SO2	SR, ODEQ reports
i21	Mercury (Hg) Emissions of service to retail and outside PGE territory	Health&Comm.	21, 22, 23	7.7	7.5	5.9	kg Hg	SR, ODEQ reports

PGE shared draft iCBI metrics at the May and June 2026 Roundtables.[158] The metrics included here vary slightly to enhance PGE's ability to compare historical data over a three-year period for a large volume of metrics. Some metrics have been refined to focus on PGE service area and existing definitions and programs, rather than reporting by previously proposed 'targeted communities', to use this first iteration to better understand what more detailed scope may be most of-interest to stakeholders and communities, as well as most informative for PGE tracking and future decision-making. For example, draft metrics included mapping and report-out based on Justice40 federal definitions of disadvantaged communities, but for these final metrics, report-out is for the service area level. PGE will continue to explore refining this process in future CEP/IRP processes.

Unlike pCBIs and rCBIs, iCBIs are not incorporated in IRP modeling or portfolio analysis outputs, since for the most part, the 21 iCBIs cannot be directly linked to individual planning and resource decisions considered in the CEP/IRP planning framework. However, collection and monitoring of these metrics is, and has been historically, informative to utility implementation decisions to help evaluate whether planned, or aimed for, community benefits of various investment decisions, contracts, programs, and otherwise are being delivered.[159] Figure 104 illustrates the process by which these metrics inform PGE actions. Compiling a summary of this range of already tracked data here in the CEP/IRP helps further highlight for PGE key topic areas with community impact into which PGE can continue to dive deeper.

Figure 104. Current iCBI Tracking and Use



A number of the iCBI metrics included capture impacts to low-income, energy burdened, and environmental justice communities. Tracking over time helps PGE understand potential impacts to these communities to continue to refine and develop programs to support communities, such as is seen through improvements over time in Table 47 to iCBIs that track access to transportation electrification, IQBD bill assistance participation and spending, EE and DR program participation or spending, community education through engagement, and air quality. As noted above, the iCBIs were identified for look-back tracking based on available existing data and collection activities,

[158] Appendix Section C.2.7 and Appendix Section C.2.8.
[159] OAR 860-90-0060(7)(g)(E) and OAR 860-90-0100(4).

which each come from robust existing procedures and reports, which tie to PGE business actions and decision-making that range beyond what is identified through planning processes.

As noted, this is PGE's first iteration on reporting out measured values of historical data for CBI tracking. PGE will continue to review and refine this approach through planning processes, with the CBIAG, and other stakeholders. Figure 105 summarizes the current availability of iCBI metrics by each CBI, as informed by the report-out metrics available and "CBI #s" column of Table 47.

Figure 105. List of CBIs by OPUC Category and iCBI Tracking Status

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

By OPUC Category

- Economic Impacts
- Environmental
- Energy Equity
- Resiliency/Reliability
- Health + Community Wellbeing

By iCBI Tracking Status

- ● Available & quantifiable historical data (at least 2-3 years)
- ● Metric is still being evaluated

As shown in Figure 105, while PGE has included one or more iCBIs for each of the five OPUC categories, there are five CBIs for which PGE has not included iCBI historical measured values. PGE is continuing to evolve the iCBI approach for tracking and reporting-out metrics. In the future, PGE may consider new data and procedures for these CBIs,[160] such as:

- CBI #2: tracking and report-out may be developed relating to PGE's efforts with the Oregon Clean Energy Workforce Coalition and/or regarding labor standards in response to HB 2021, or in relation to future workforce associated with new construction and procurements.
- CBI #7: new and consistent tracking procures may be considered in relation to actions, spending, and/or locations served as relating to ancillary services.
- CBI #12: different public disclosure of business activities with Tribes may be considered.
- CBI #19: different public disclosure of regular customer survey data collection that may include insights regarding satisfaction/pride may be considered.

[160] OAR 860-90-0100(5).

- CBI #30: new and consistent tracking procures may be considered in relation to safety from natural disasters.

Similarly, as PGE continues to review available data or consider new data collection for alignment with CBIs, as well as continues to engage and consider the feedback of the CBIAG and environmental justice communities, PGE may change CBIs to better reflect community interests.

PGE may also refine its reporting and data sharing in "Key Data Sources" to continue to bolster and provide detailed information on actions, learnings, and activities. For example, many detailed engagements on ranging topics informed Metric #i7 on Community Engagement, through which PGE spoke with the CBIAG as well as environmental justice communities, students, organizations, and other members of the public to both increase awareness of utility programs as well as learn about what topics are considered important to communities. A key learning PGE found through these engagements aligns with other report-out and narratives of the CEP/IRP in that high energy burden remains concentrated among low-income households, reinforcing affordability as a priority for utility decision-making. Though Appendix C describes some of these activities as they relate to planning, more robust tracking and description of all PGE outreach could be better organized and reported on PGE's website or otherwise. PGE may consider improvements to this kind of tracking and reporting in future.

Additionally, other data, information, and reports, whether in planning cycles or collected annual or not, inform PGE's actions when it comes to community outcomes. For example, in 2024, PGE engaged a consultant to conduct an energy burden assessment,[161] the learnings from which continue to inform PGE's actions as they relate to ratemaking, low income needs, program development, affordability, and more.

D.5 Challenges and Next Steps

In consideration of the principles outlined in HB 2021, PGE has continued to evaluate potential strategies for improving clean energy accessibility, assessing projects that may provide benefits to disadvantaged communities, and pursuing clean energy and equity objectives, while maintaining a focus on meeting load requirements and striving for cost-effective solutions for customers.[162] In the range of efforts to advance this work, PGE continues to face several challenges integrating CBIs into IRP processes.

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. The CBRE RFO has served as a valuable tool for market research on project costs and CBIs for this planning cycle and for informing the Company's next steps. The insights gained from this process, including evaluations by CBIAG and engagement with OPUC Staff have been incorporated into this plan to demonstrate PGE's commitment to understanding and valuing community benefits. PGE, along with stakeholders,

[161] https://edocs.puc.state.or.us/efdocs/HAD/um2211had329831054.pdf
[162] Oregon House Bill 2021, Section 1(3)(a), 2021 Regular Session, https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB 2021/Enrolled

continues to identify a need for further primary research to reflect local conditions and policy goals and looks forward to continued engagement with stakeholders on the method, scope, and objectives of this research for continuing to refine and inform planning and project- and program-related efforts.

Another key challenge lies in the limitations of proxy metrics, which require a balance between precision and usability. These metrics must provide meaningful insights while remaining practical for use in resource planning. For example, while pCBI proxy metrics used in CEP/IRP portfolio analysis can be included and considered in RFP portfolio analysis as required by OPUC rules, their usefulness as a prioritization or selection criteria when considering final shortlist composition may be limited, as pCBI applicability may not capture genuine differences between competing utility-scale renewable project proposals.[163] In the 2025 RFP, following consultation with community stakeholders, PGE required bidders to provide information on community benefits associated with proposed projects. Bidders' responses highlighted positive project impacts on local jobs, local tax revenues and economic development, partnering local organizations, and agricultural research. One or more bids also asserted positive impacts on local resilience, which PGE did not verify. PGE sees value in continuing to refine expectations for bidder-provided CBI information, as complementary data to the IRP's CBI framework. In future RFPs, PGE also intends to increase transparency of reporting on proposed CBI opportunities and commitments to regulatory and community stakeholders. PGE intends to continue iterating its approaches to collection and use of CBIs in the context of RFPs, with continuing engagement with stakeholders and the CBIAG to refine the approach.

Continued 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. In the meantime, CBI analysis at this time is distinct from other scoring metrics and still practically informative to utility implementation decisions, as noted above and as seen throughout time as informing investments, contracts, program designs, and RFO and RFP requirements.[164]

[163] OAR 860-89-0475(5)
[164] OAR 860-90-0060(7)(g)(E) and OAR 860-90-0100(4).

Appendix E DEQ Emissions

Per 860-090-0100(11), PGE is to include in its CEP the electric company's two (2) most recent annual emissions data reports filed with the Oregon Department of Environmental Quality.

The Greenhouse Gas Emissions reported to ODEQ are available at: https://www.oregon.gov/deq/ghgp/Pages/GHG-Emissions.aspx.[165]

[165] Two most recent years include 2024 (final) and 2025 (verification may not yet be finalized at the time of this 2026 CEP/IRP filing).

Appendix F Existing PGE Systems and Contracts

PGE is a vertically integrated electric utility encompassing generation, transmission and distribution. PGE is Oregon's largest electricity provider, serving roughly 960,000 retail customers within a service area of nearly 2 million residents. Roughly two-thirds of Oregon's commercial and industrial activity occurs in PGE service area.

F.1 PGE System Overview

PGE meets the growing clean energy demands of customers and State requirements with a diverse mix of generation facilities shown in Figure 106 owned in whole or in part, or through contract, as described in the next section.[166] 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. Over the past few years, PGE acquired more than 475 MW of battery storage projects that are now online and announced acquisition of an additional 400 MW of contracted capacity estimated for commercial operation by the end of 2028.

Figure 106. 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 380,500 MWh of non-emitting energy in PGE service territory in 2025. 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. To

[166] Figure image from PGE 2025 Purpose and Progress report, https://downloads.ctfassets.net/416ywc1laqmd/v4ZsP7g6rt5Y8guOQVR4m/5435351a61703614b00c3c4048b4bc7d/412651-2025-ESG-Report-Print_FNL-03.12.26.pdf.

secure transmission access and additional power on contract for customers, PGE actively coordinates with transmission providers, like the Bonneville Power Administration, and other utilities and energy suppliers across the region. 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 Extended Day-Ahead Market (EDAM). These options provide additional flexibility to buy and sell power and access a more diverse and increasingly clean mix of generating resources.

F.2 Existing and Contracted Resources

PGE operates a diverse portfolio of resources to meet the system's energy and capacity needs. This section describes existing resources and resources with executed agreements that may not yet be in service but become relevant for forward-looking analysis of the IRP.[167] In alignment with OAR 860-090-0060(6), the capacity and energy needs assessments do not include any incremental actions beyond known commitments at the time of the analysis. The base existing portfolio and forward-looking assumptions described in the following subsections are primarily informed by current contracted agreements and PGE's 2026 Annual Power Cost Update Tarriff (AUT). Figure 107 and Figure 108 illustrate the type, size, and ownership diversity of PGE's existing resource portfolio.

[167] The reported annual average energy availability (in MWa) for resources here is for the period 2026 to 2050, unless otherwise noted.

Figure 107. PGE Generation Portfolio by Type and Capacity

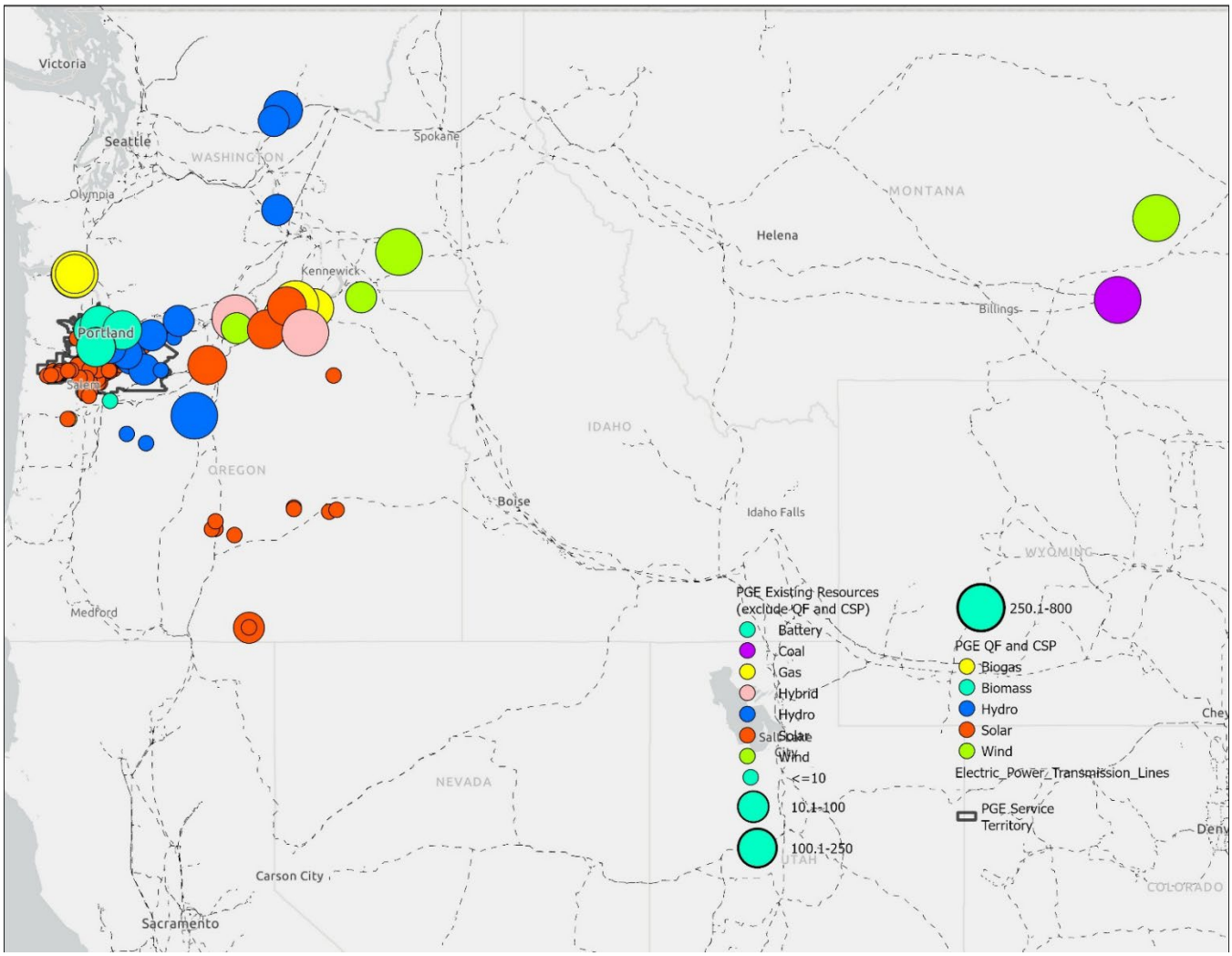
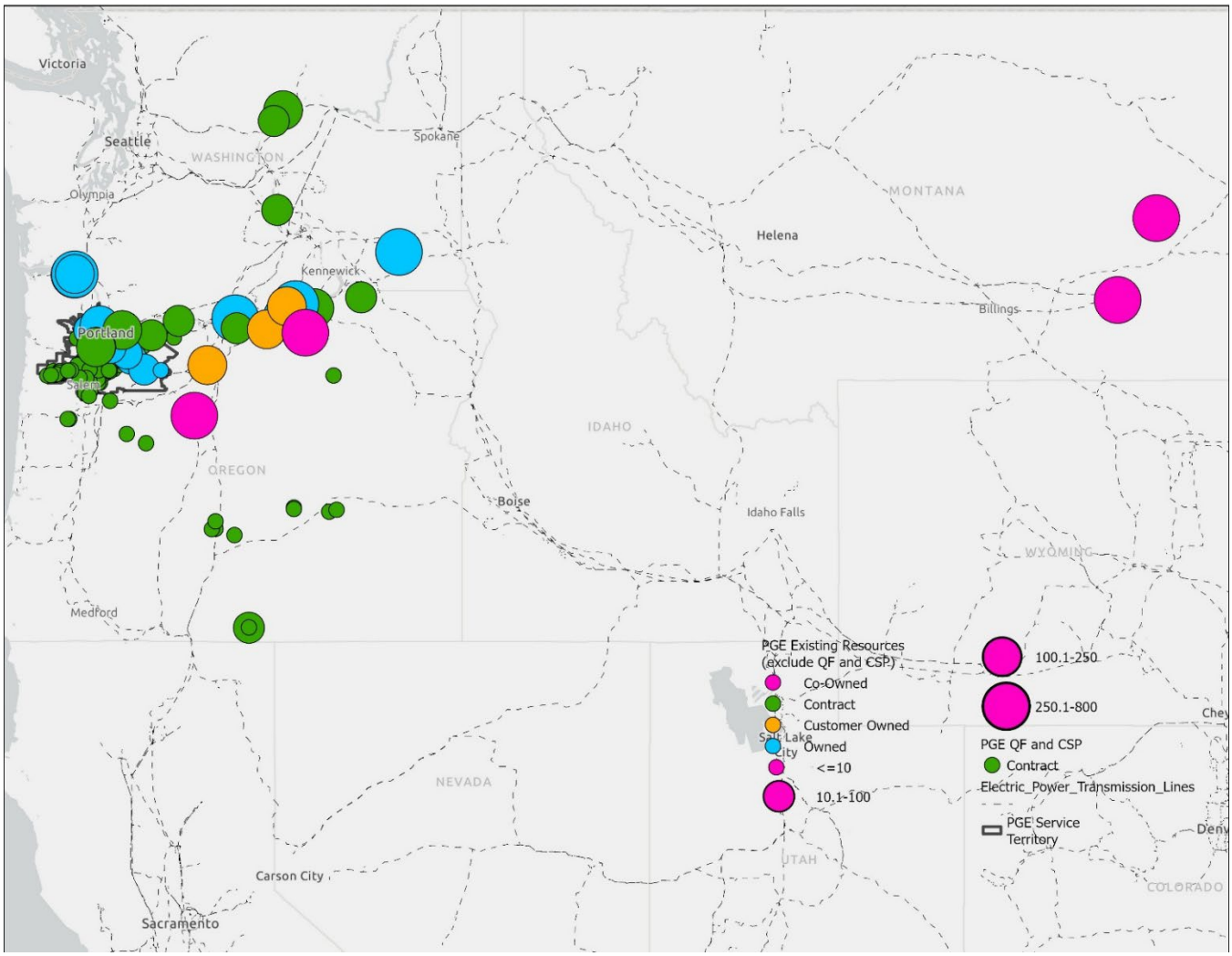


Figure 108. PGE Generation Portfolio by Ownership and Capacity



F.2.1 Thermal Resources

The following subsections detail technology and size characteristics for each thermal plant. Values detailing capacity (MW) are annual average net capacity of the power plant, including duct-firing capabilities and excluding de-rates for maintenance or forced outage rates. Comparatively, energy (in MWa) represents the annual average availability after projected forced outages and maintenance. Also, note that the capacity of combined-cycle combustion turbines (CCCTs) varies across seasons as turbine operations change with temperature changes. These turbines provide less capacity when temperature is high during the summer, while other steam technologies have more consistent capacity regardless of temperature change. Forward-looking IRP analysis includes modeling assumptions for de-rates and seasonal variations.

F.2.1.1 Beaver

Beaver is a CCCT facility in Clatskanie, Oregon. PGE placed the plant into service in 1976. Beaver has an annual average capacity of 486 MW. The six combustion turbines (CTs) operate primarily on

natural gas but can also be fueled with No. 2 diesel fuel oil via on-site tank storage. The CTs have heat recovery steam generators that connect to a single steam turbine, allowing PGE to operate the plant either in simple-cycle mode or in combined–cycle mode. A separate simple cycle unit, Beaver 8, was added to the site in 2001 and has an annual average capacity of 23 MW.

F.2.1.2 Carty

Carty is a CCCT resource built adjacent to PGE's retired Boardman coal plant in Boardman, Oregon. The plant became operational in 2016. It provides 391 MW of annual average capacity. The plant has a highly efficient Mitsubishi Heavy Industries (MHI) G-class combustion turbine. The annual average energy availability is 380 MWa, and the plant has 47 MW of duct firing for capacity needs.

F.2.1.3 Coyote Springs

Coyote Springs is a gas fired CCCT facility in Boardman, Oregon, which became operational in 1995. It has an annual average capacity of 258 MW, including 2 MW of additional capacity when operating an auxiliary boiler to supply steam-to-steam customers, and an annual average energy availability of 232 MWa.

F.2.1.4 Port Westward 1

Port Westward 1 (PW1) reached commercial operation in June 2007. This CCCT plant is in Clatskanie, Oregon. The plant supplies approximately 411 MW of annual average capacity, including roughly 17 MW of duct firing, and has an annual average energy availability of 371 MWa.

F.2.1.5 Port Westward 2

Port Westward 2 (PW2) is in Clatskanie, OR, adjacent to PGE's PW1 plant. PW2 began commercial operations in December 2014. It is comprised of 12 natural gas-fired reciprocating engines with an annual average capacity of approximately 225 MW. In addition to providing peak capacity, the modular configuration offers a wide range of dispatch flexibility for wind, load following, and additional energy value.

F.2.1.6 Colstrip

Colstrip is a four-unit coal-fired plant located in Colstrip, Montana, with coal transported by conveyor belt directly from the on-site mine to the boiler. Colstrip units 1 and 2 became operational in 1975 and 1976, respectively, and were shut down in 2019. These two units were owned by Talen Energy and Puget Sound Energy. PGE owns 20% of Colstrip units 3 and 4, representing approximately 296 MW of annual average capacity. The average annual energy availability for PGE's share of Colstrip Units 3 and 4 is 242 MWa. In order to meet PGE's regulatory, legislative, and reliability requirements, the Company continues to evaluate its ongoing ownership interest in Colstrip.

F.2.1.7 Calpine's Hermiston

PGE contracts a heat rate call option (HRCO) from Calpine for 250 MW of capacity from the Hermiston combined-cycle natural gas plant in Hermiston, OR. In 2025, PGE signed a contract with

Calpine to extend the 250 MW HRCO from 2029 to 2034.[168] This contract and its extension provide dispatchable firm capacity necessary to meet customer demand.

F.2.2 Owned Hydroelectric Power Plants

PGE owns and operates eight hydroelectric plants on the Deschutes, Clackamas, and Willamette River systems. Pelton and Round Butte plants have reservoir storage capability, while the remaining plants have limited ability to store water and shape energy. These plants are operated as run-of-river projects. These hydroelectric power plants are considered eligible renewable energy generators toward the state's RPS requirements, up to the low impact hydro limits of the regulation.

F.2.2.1 Pelton-Round Butte Hydropower Project

PGE operates the Pelton and Round Butte plants on the Deschutes River near Madras, Oregon. These plants provide peaking and load-following capabilities. A portion of PGE's hydropower capacity also contributes to meeting the required spinning and supplemental (non-spin) operating reserve requirements, which are necessary for responding to system contingencies. Contingency reserve requirements were updated in the WECC on April 14, 2026, but not reflected in 2026 CEP/IRP modeling assumptions. See Appendix Section H.2.1.1 for more detail.

During average hydro conditions, the plants have a combined annual average capacity of approximately 460 MW and an expected annual energy production of 141 MWa. PGE owns 50.1% of each plant (approximately 230 MW, 70 MWa). The remaining share is owned by the Confederated Tribes of the Warm Springs Reservation (CTWSR), who contracted with PGE to sell all output from their share of the projects to PGE through 2040. See Appendix Section F.2.3.3 for more details on the agreement.

F.2.2.2 Clackamas River Hydropower Projects

PGE owns and operates six plants on the Clackamas River system. During average hydro conditions, the plants have the following average annual capacities:

- Harriet Powerhouse, 0.6 MW
- Timothy Powerhouse, 1.3 MW
- River Mill, 25 MW
- Faraday, 42 MW
- Oak Grove, 44 MW
- North Fork, 58 MW

The aggregated expected annual energy production from these projects totals approximately 74 MWa during average hydro conditions.

[168] Consistent with past CEP and IRP Update methodologies, the quantity of emitting energy retained to serve PGE's load is limited to quantities that are compliant with HB 2021 GHG emissions targets in relevant scenarios. The quantity of energy retained from the Calpine project is determined by the new PZM modeling. For more information, see Appendix Section H.2.2 and Appendix Section I.2.

F.2.2.3 Willamette Falls Hydro Projects

PGE owns and operates the Sullivan plant on the Willamette River at Willamette Falls. During average hydro conditions, the plant's nameplate capacity is 18 MW and expected annual energy production is 12 MWa.

F.2.3 Contracted Hydroelectric Power

Hydro contracts provide both energy and capacity to PGE's resource portfolio. Capacity values in the following subsections represent annual average availability values, not plant capacities.

F.2.3.1 Mid-Columbia Hydro Projects

PGE has a share of some hydropower facilities on the mid-section of the Columbia River (Mid-C). This means that PGE has proportional rights to the project reservoirs, allowing for energy shaping across hours and days. PGE can utilize these resources to provide ancillary services, including regulation and spinning reserves. Power from these hydroelectric contracts is considered eligible renewable energy generation toward the state's RPS requirements, up to the low impact hydro limits of the regulation.

Wells Project: Located downstream of Chief Joseph and completed in 1967. The 10-turbine facility is operated by the Douglas County Public Utility District No. 1 (Douglas PUD). Upon the contractual expiration on August 31, 2018, and per OPUC Order No. 14-415, PGE sought to renew all or a portion of the Wells contract if a cost-effective agreement could be reached. PGE reached a new agreement with Douglas PUD for projects through September 30, 2028. Douglas PUD and PGE currently have an agreement to supply PGE with approximately 65 MWa of output from the Wells Hydroelectric Project on the Columbia River north of Wenatchee, Washington for years 2026-2030.

Priest Rapids Project: Located downstream of Rock Island and consists of the Wanapum Dam (10 units, completed in 1964) and the Priest Rapids Dam (10 units, completed in 1961). Both facilities are operated by the Grant County PUD No. 2 (Grant PUD). PGE has contractual rights to approximately 8.27% of each facility through the spring of 2052. The combined annual average dependable capacity of PGE's share is approximately 61 MW, and the expected annual average energy under average hydro conditions is 43 MWa. Both values are prior to PGE's associated Canadian Entitlement obligations, as discussed in the following section.

Rocky Reach and Rock Island Projects: Located between the Wells and Priest Rapids Projects, Rocky Reach Dam (11 units, completed in 1961) and Rock Island Dam (19 units, original construction completed in 1933) are operated by Chelan County PUD No. 1 (Chelan PUD). PGE participated in a Chelan PUD reverse RFP process in 2026 for long-term access to a portion of the output of the Rocky Reach and Rock Island projects, which concluded in summer 2026. PGE entered into two new PPAs with Chelan PUD, with a combined output under average conditions of 49 MWa:

- For Rocky Reach, a 10-year PPA for 5% of facility output beginning January 1, 2027;
- For Rock Island, a 10-year PPA for 5% of facility output beginning January 1, 2027.

Because PGE did not enter into definitive agreements until July 2026, these PPAs are not included as existing resources in PGE's planning analysis. However, implications of PGE's consideration of hydro contract extensions are considered as a sensitivity, as described in Appendix Section H.6.10.

F.2.3.2 Canadian Entitlement Allocation

An agreement was entered between the U.S. and Canada in which the U.S. shares a portion of the generation benefits from the Columbia River storage reservoirs in Canada.[169] This agreement for the entitlement benefits ended in 2003 but was extended to 2024. PGE's share of Mid-C projects (Wells, Wanapum, and Priest Rapids) are subject to the Canadian Entitlement Allocation Extension (CEAE) obligations. For the IRP, PGE reflects the Columbia River Treaty by assuming that the CEAE renews after 2024 (or that the net effect of any operating changes after the expiration is approximately the same as if the agreement is renewed). PGE models this as the delivery of on-peak power to Canada.

F.2.3.3 Pelton, Round Butte, and the Re-Regulating Dam

As discussed in Appendix Section F.2.2, the CTWSR own a 49.99% share of the Pelton and Round Butte plants and 100% of the associated Re-regulating Dam (Re-reg Dam, 10 MW, 10 MWa), operated by PGE. PGE contracts for the entire CTWSR share of Pelton, Round Butte, and Re-regulating Dam through 2040.

F.2.4 Wind, Solar, and Hybrid Projects

PGE has increasingly procured renewable energy and hybrid renewable and storage projects over the past few decades. This diversifies PGE's mix of resources with complementary types that support the system at different times, aid in price stability, and reduce risk from variable fuel price spikes, providing benefits to customers and the system. These resources support progress toward clean energy goals and state RPS requirements, as wind and solar generation is considered renewable energy. For hybrids, the battery storage output does not result in Renewable Energy Certificate (REC) generation as batteries do not contribute toward RPS requirements.

F.2.4.1 Biglow Canyon

The Biglow Canyon Wind Farm was completed in three phases in 2007, 2009, and 2010. The wind farm is in the lower Columbia River Gorge near Wasco, Oregon, with a total nameplate capacity of 450 MW. Biglow has estimated annual average energy production of 114 MWa, or a capacity factor of approximately 28%.

F.2.4.2 Tucannon River Wind Farm

PGE's Tucannon River Wind Farm is located near Dayton, Washington. It began operating in December 2014 and consists of 116 Siemens wind turbines, 2.3 MW each, for a total nameplate

[169] The Columbia River Treaty, ratified in 1964, required the U.S. to deliver one-half of three storage dams to Canada under the Canadian Entitlement Allocation Agreements (CEAA). Canadian Entitlement Allocation Extension Agreements, April 29, 1997, available at: https://www.bpa.gov/-/media/Aep/about/publications/records-of-decision/1997-rod/rod-19970427-canadian-entitlement-allocation-extension-agreements.pdf.

capacity of 267 MW. The plant has an approximately 35% capacity factor, resulting in an expected output of 93 MWa.

F.2.4.3 Wheatridge Renewable Energy Facility

In 2019, PGE entered into agreements with NextEra for the Wheatridge Renewable Energy Facility in Morrow County, Oregon. The facility consists of 300 MW of wind, 50 MW of solar, and 30 MW of battery storage. The wind portion of the facility entered service at the end of 2021, and the solar and storage components began service in 2022. PGE owns 100 MW of the wind generation and holds a long-term power purchase agreement (PPA) with NextEra for the remainder of the project.

F.2.4.4 Clearwater Wind Energy Center

The Clearwater Wind Energy Center spans Rosebud, Garfield, and Custer counties in Montana. It is a 775 MW wind site developed by NextEra Energy Resources, LLC. As of early 2024, PGE procures 311 MW from the Clearwater Wind project (208 MW owned and 103 MW from power purchase agreement) generated by 112 General Electric wind turbines. The power is served to PGE customers through existing transmission on the Northwestern Energy and Bonneville Power Administration (BPA) systems. With an expected capacity factor of nearly 44%, this project delivers higher levels of production during the winter and summer compared to PGE's other wind projects. PGE's estimated share of Clearwater's annual average energy production is 137 MWa.

F.2.4.5 Biglow Solar Generation and Battery Energy Storage System (BESS)

Through the 2023 RFP procurement process, PGE finalized acquisition of the Biglow Solar Generation and BESS project in February 2026. This hybrid solar and storage project will be located in Sherman County, Oregon, adjacent to PGE's existing Biglow Canyon wind farm. The project consists of 125 MW of solar paired with 125 MW of battery storage, anticipated to be online by the end of 2027.

F.2.4.6 Wheatridge Expansion

During the 2023 RFP procurement process, PGE finalized acquisition of the Wheatridge Expansion project. This will add 240 MW of solar and 125 MW of battery storage to PGE's existing Wheatridge Wind, Solar, Storage project in Morrow County, Oregon. This expansion portion is anticipated to be online by the end of 2027 and PGE will jointly own the capacity, while contracting for all output from the project through a long term PPA.

F.2.5 Standalone Energy Storage

F.2.5.1 Existing

As of December 31, 2025, PGE's standalone battery storage portfolio includes more than 490 MW of capacity, not including battery storage capacity co-located with renewables (discussed in preceding subsection):

1. Coffee Creek, 17 MW in Sherwood, Oregon, PPA through 2030
2. Constable (formerly Evergreen), 75 MW in Hillsboro, Oregon, owned by PGE
3. Seaside, 200 MW in Portland, Oregon, owned by PGE

4. Sundial (formerly Troutdale), 200 MW in Troutdale, Oregon, PPA through 2044
5. Port Westward 2, 4 MW coupled at the Port Westward 2 Generating Station

F.2.5.2 Meadowlark

Announced in 2026, PGE finalized a long-term PPA for 200 MW of capacity from Meadowlark Battery storage project. The project is to be located in Washington County, Oregon, and anticipated to be online by the end of 2027.

F.2.5.3 Nottingham

Announced in 2026, PGE finalized a long-term PPA for 200 MW of capacity from Nottingham Battery storage project. The project is to be located in Washington County, Oregon, and anticipated to be online in 2028.

F.2.6 Bilateral Capacity Agreements

PGE previously had bilateral capacity agreements with Bonneville Power Administration for annual capacity and Avangrid Renewables for seasonal peak capacity during summer and winter. However, these contracts have expired by the 2027-2046 time horizon analyzed in this IRP.

F.2.7 Additional Contracts

Table 48 summarizes additional contracted resources in PGE's existing portfolio, excluding qualifying facilities (QFs), which are described in the following subsection.

Table 48. Additional Contracts by Technology, MW

	2027	2030	2035	2040	2045
Hydro	42	42	5	5	5
Solar[170]	538	538	538	145	9
Wind	99	75	75	-	-

F.2.8 Qualifying Facility (QF) Contracts

- PGE contracts purchase of output from numerous QF projects. This IRP includes known QF contracts as of end of 2025, totaling approximately 403 MW from 2027 through 2046. Table 49 and Table 50 summarize the QF contracts by technology and year-end capability.

[170] Solar includes green future initiatives, community solar PPA, and PPA.

Table 49. Qualifying Facility Capacity by Technology, MW

	2027	2030	2035	2040	2045
Biomass	10.0	10.0	7.5	7.5	7.5
Biogas	7.8	7.8	7.8	7.8	7.8
Hydro	7.1	7.1	6.1	5.4	5.4
Solar	368.9	368.9	321.0	298.4	253.8
Wind	9.0	9.0	6.8	6.8	6.8
Total	403	403	349	326	326

Table 50. Qualifying Facility Average Energy by Technology, MWa

	2027	2030	2035	2040	2045
Biomass	5.5	5.5	4.1	4.1	4.1
Biogas	8.0	7.0	7.0	7.0	7.0
Hydro	4.1	4.1	3.6	3.1	3.1
Solar	83.6	83.6	74.7	68.7	68.7
Wind	3.0	3.0	2.2	2.2	2.2
Total	104	103	92	85	85

Assumptions for planning analyses are made regarding the future of known QF contracts. First, in accordance with Order 24-096, PGE assumes a 75% success rate for MWs contracted but not yet executed. Second, in accordance with Order 24-096, PGE assumes a 75% renewal rate of QF capacity for years after contract termination.[171] This renewal assumption is incorporated into all scenarios and the two tables above.

New QFs are not included as a proxy resource option within IRP portfolio analysis and capacity expansion modeling. As each contract size, pricing, need, and likelihood of a QF contract is unique, PGE believes modeling QFs as a generic resource option is generally not informative for planning or decision-making. Instead, representative proxy resource options are modeled for IRP, representing a range of utility-scale supply-side technologies, proxy CBREs, and additional analysis relating to the small-scale renewable requirement. For more information, see Appendix G.

[171] As directed by OPUC in Docket No. LC 80, Order 24-096, Section VII.B.5, the base existing portfolio and needs assessment assume a 75% QF renewable success rate.

F.3 Customer Side

PGE's system benefits from long-running customer programs to promote energy efficiency and flexibility.

F.3.1 Energy Efficiency

PGE began working with the Energy Trust of Oregon (ETO) in 2002 to identify and acquire cost-effective energy efficiency measures that help customers reduce their energy use. Oregon is a national leader in capturing energy efficiency through the combined efforts of ETO, customers, and utilities. PGE's collaboration with ETO has matured significantly and is working well through a combination of formal governance structures, routine engagement, and shared planning processes. Through ETO programs, PGE customers may achieve incremental savings of approximately 36 MWa per year from 2027 through 2031. Section 6.2.4 and Appendix Section G.1 discuss the long-term energy efficiency savings forecast by ETO for this IRP, and Appendix P contains a report from the Energy Trust describing their forecasting and cost-effectiveness screening methodology. Appendix Section H.6.7.6 describes how EE is incorporated into PGE's load forecast.

While Energy Trust's energy efficiency acquisition has met targets, costs have increased significantly as energy efficiency avoided costs approved by OPUC in Docket No. UM 1893 have risen. Since 2023, ETO's budget for PGE customers has increased approximately 40%, while forecasted savings have only increased 22%, highlighting the importance of focused efforts to coordinate and prioritize activities.

The Utility Specific Action Plan (USAP) framework provides the primary mechanism for coordinating activities, with initiatives now structured as 18-month action plans that are updated quarterly and reported transparently through the USAP process. The recently developed Offer/Technology Coordinated Delivery Roadmap further strengthens this relationship by establishing a common framework for co-delivery, co-marketing, and co-development activities, while defining governance, reporting cadences, and points of accountability. Through this structure, PGE and Energy Trust are actively coordinating initiatives such as Home Energy Reports, industrial control systems, multifamily income-qualified efforts, thermostats, and solar plus storage opportunities. The roadmap recognizes that both organizations serve many of the same customers and can create greater value through coordinated deployment of demand-side management offerings, incentive stacking, and aligned customer engagement strategies.

At the same time, the transition to Energy Trust's 2026–2030 Multiyear Plan creates an important shift in the nature of the policy conversation. Because the overall budget is now fixed across the five-year planning horizon, annual updates to avoided costs no longer meaningfully influence total program spending; instead, they influence how expenditures are allocated among programs and measures. As PGE noted in Docket No. UM 1893, avoided cost updates now function primarily as inputs to Energy Trust's adaptive management framework, informing decisions about incentive levels, program adjustments, reallocation of funding, and the continuation of pilots. Under this model, discussions will increasingly focus on whether limited dollars are being directed toward the most cost-effective opportunities or toward activities pursued primarily for policy, equity, or energy burden objectives. The adaptive management process appropriately provides flexibility to respond

to changing market conditions, but it also heightens the importance of clear decision criteria for determining when resources should shift between cost-effective and non-cost-effective portfolios.

As implementation progresses, there remain several opportunities for clarification that would improve transparency, accountability, and stakeholder confidence. First, performance measurement frameworks warrant further development. While the multiyear plan emphasizes outcomes-based planning, PGE has noted the absence of sufficiently specific numerical goals, timelines, and accountability mechanisms within several areas of the plan. Relatedly, changes to Energy Trust performance measures, including the removal of levelized cost of energy as a standalone metric and the increased reliance on portfolio-level cost-effectiveness screening, make it important to clarify how success will be measured and what guardrails will govern non-cost-effective investments. Additional transparency regarding adaptive management triggers, corrective actions, and reporting expectations would further strengthen confidence that expenditures remain aligned with intended outcomes.

PGE has also identified opportunities to improve clarity around program cost allocation, co-deployment readiness, and customer delivery pathways. Although Energy Trust allocates costs based on cost drivers and utility territories, the underlying methodology is not sufficiently visible to support evaluation of alternative approaches or coordinated planning. Similarly, greater transparency into measure development pipelines, Measure Approval Document (MAD) lifecycles, and readiness for coordinated deployment would help utilities align program design and implementation efforts. Finally, referral workflows and data-sharing practices present important opportunities for enhancement, particularly for income-qualified customers where indirect referral structures may create barriers to participation. Continued refinement of reporting structures, allocation methodologies, performance metrics, and collaboration processes would build upon an already strong partnership and help ensure that the multiyear plan delivers both accountability and maximum value for customers over the planning horizon.

F.3.2 Virtual Power Plant

PGE's Virtual Power Plant (VPP) is a grid-integrated resource that orchestrates more than 600 MWs of capacity from over 230,000 participating customers. PGE operates the VPP as a coordinated portfolio of programs including distributed energy resources, dispatchable standby generation, customer-sited storage, and managed transportation electrification. These programs are integrated through customer and grid platforms to form a resource that provides both energy and capacity. Existing demand response programs, distributed generation (i.e., rooftop solar), and dispatchable standby generation deployment are described in Section 1.2.3. See Appendix Section H.1 for more on how VPP and these customer-side resources are forecasted for use in IRP analysis.

Table 51. VPP Portfolio in MW for Summer and Winter - Actuals as of end of 2025

Existing VPP Portfolio	Summer	Winter
Energy Partner on Demand Program - Commercial (Schedule 26)	43.4	34.0
Energy Partner Thermostat - Commercial (Schedule 25)	2.4	0.5
Smart Thermostat Program - Residential	45.2	9.7
Peak Time Rebates Program (PTR) - Residential	18.5	14.3

Existing VPP Portfolio	Summer	Winter
Time of Day (TOD) - Residential	3.8	
Smart Charging - Residential	2.5	2.5
Multi-Family Water Heater Pilot	1.5	1.8
Total Flexible Load Portfolio	117.3	62.8
Other VPP Resources		
Rooftop Solar Program	311.0	311.0
Distributed Batteries	2.4	2.4
Smart Battery Pilot	2.9	2.9
Dispatchable Standby Generation	127.0	127.0

Appendix G Resource Options

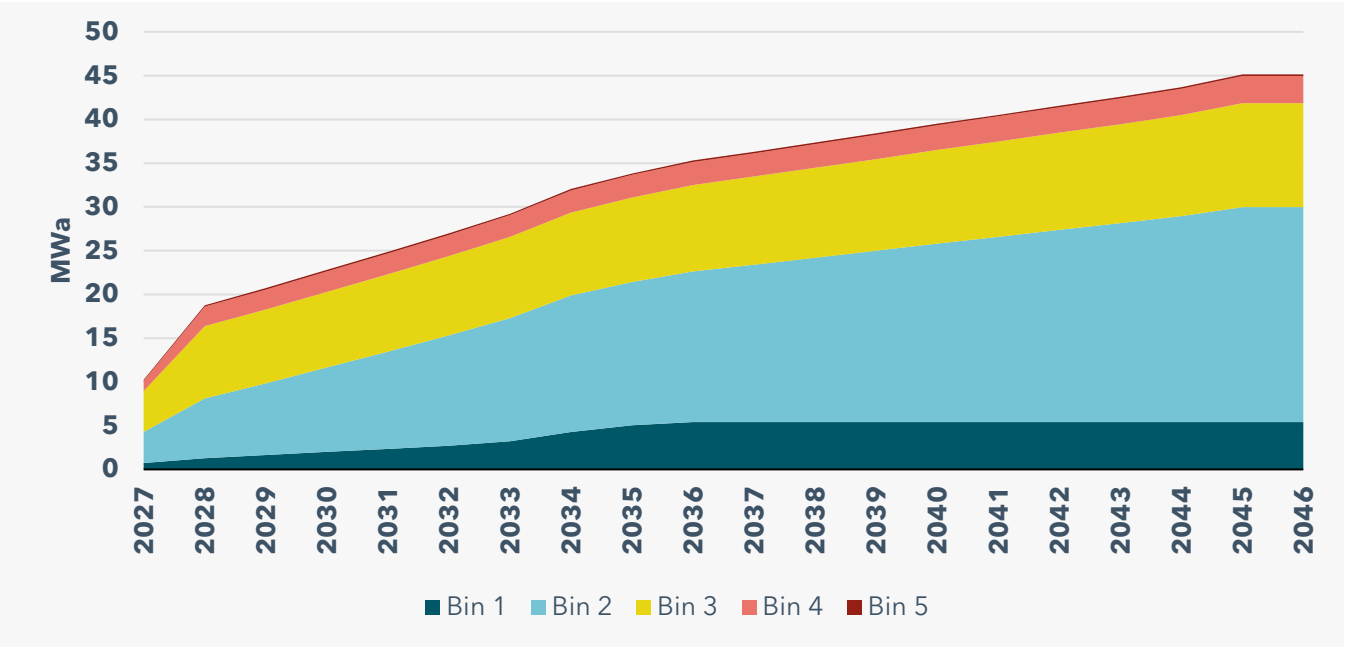
G.1 Non-cost-effective Energy Efficiency

As described in Section 6.2.4, PGE relies on an EE savings forecast from ETO for the IRP. Cost-effective EE is built into the load forecast while EE measures that do not pass the UM 1893 and ETO implementation of the cost-effectiveness screening are bundled into five discrete bins and made available for selection in portfolio analysis.

For bundling the dozens of non-cost-effective (NCE) EE measures into five simpler bins for IRP analysis, PGE adopted a process similar to the Norwest Power and Conservation Council where measures are aggregated into bins based on their levelized cost. The levelized cost ranges used to determine the size of each bin were defined through K-means cluster analysis. The size of each bin is the average MW potential of the measures within that bin by year, where total potential savings in each bin varies and includes a combination of residential, commercial, and industrial measures (depending on costs). For any given year, the lowest cost measures are grouped in bin 1, increasing to highest cost measures in bin 5.

Resulting cumulative potential savings by bin is shown in Figure 109. This shows the maximum amount of NCE EE that may be selected in portfolio analysis (depending on costs and other model constraints), for up to 45 MWa across the 20 years. This total cumulative potential of NCE EE in any year is lower in this IRP compared to previous IRPs due to the cost-effectiveness screening described in Section 6.2.4.1, finding more measures in this year's analysis to be cost-effective and therefore built into the load forecast.

Figure 109. Cumulative NCE EE Potential by Bin



Cost assumptions for IRP portfolio analysis for each bin are based on a weighted average of the measures within, weighted by their megawatt average (MWa) potential. PGE also included benefits based on the UM 1893 filing,[172] by including a commensurate reduction in the fixed costs resulting from a distribution deferral credit, a regional Power Act credit of 10%, and a risk reduction value. Capacity factors, ELCCs, and energy values for each bin are also calculated to characterize these NCE EE resources available for selection in portfolio analysis.

Table 52 summarizes each bin for the first five (5) years, highlighting fixed costs, MWa potential, and associated end uses. As the bins are developed based on levelized cost, the number and proportion of end use in each bin changes each year. The end uses shown in the table represent an aggregated set of unique measures referencing different market opportunities. For example, weatherization end uses in different bins contain different measures that apply to different types of buildings with different heating fuels.

Table 52. Non-cost-effective Energy Efficiency Cost and Savings Potential by Bin, 2027-2031

Bin	Average Fixed Costs (2026$/kW-yr)	Cumulative Potential (MWa)	End Uses
1	$ 976	2.0	Water heating, ventilation, refrigeration
2	$ 2,391	9.7	Heating, cooling, drying, street lighting
3	$ 6,545	8.6	Cooling, heating, weatherization
4	$ 12,159	2.3	Cooling, weatherization
5	$ 111,7444	0.2	Weatherization

G.2 Virtual Power Plant Approach and Assumptions

The increasing adoption of distributed energy resources (DERs) across PGE's service territory presents a significant opportunity to address resource adequacy needs while maintaining affordability for customers and advancing the decarbonization objectives established under House Bill 2021. PGE's Virtual Power Plant (VPP) integrates customer-owned DERs through coordinated customer and grid technology platforms to provide energy, capacity, and grid services. Different types of customer-owned devices like EV chargers, smart thermostats, water heaters, and behind-the-meter generation and storage are coordinated or dispatched by PGE to reduce peak demand, support system reliability, and respond to grid emergencies. In addition to providing capacity and reliability benefits, these resources help lower customer energy costs, reduce expensive energy purchases, and support emissions reductions.

Today, PGE's VPP portfolio orchestrates more than 600 MW of flexible capacity from more than 230,000 participating customers, representing approximately 25% of PGE's customer base. Residential participation in PGE's VPP programs is approximately four times the national average. This aggregated portfolio represents a scalable and cost-effective resource that can contribute

[172] PGE's last approved UM 1893-related avoided costs used in this analysis are available at: https://edocs.puc.state.or.us/efdocs/HAQ/re182haq333279053.pdf .

meaningfully to meeting future customer energy needs. PGE works with a range of implementation partners and aggregators to enroll customers and integrate eligible resources into the VPP. PGE then coordinates resource dispatch in accordance with system needs and program requirements, measures performance, and compensates participating customers for the services provided. By leveraging existing customer-owned assets, the VPP unlocks additional value from the existing system. It serves as a complement to traditional investments in generation, transmission, and distribution infrastructure which may require significant capital expenditures and longer development timelines.

The VPP is a foundational element of the Company's planning and operations, and is incorporated across the Company's principal planning processes, including the Distribution System Plan (DSP), the forthcoming VPP Multi-Year Plan (MYP), and the Transportation Electrification Plan (TEP). The DSP evaluates distribution system needs and identifies opportunities for VPP-enabled technologies and resources to provide customer and system benefits. The 2026 VPP MYP will provide a comprehensive assessment of portfolio growth targets, cost-effectiveness, and utilization strategies. The TEP incorporates managed charging and other emerging transportation electrification technologies that contribute VPP capacity and flexibility. Within this CEP/IRP, for the first time PGE is performing more detailed modeling and analysis of the diverse DER measures which are part of VPP resources. Therefore, VPP resources are being treated as other resource options and evaluated alongside traditional supply-side resources.

G.2.1 Types of VPP Resources in IRP

PGE's VPP consists of a diverse portfolio of existing or future customer-owned DER measures which include smart thermostats, electric vehicle chargers, electric water heaters, battery storage systems, backup generators, agricultural loads, and behind-the-meter solar. For the purposes of the IRP modeling and analysis these resources have been broadly categorized into four high-level groups as below:

- Flex Load programs and pilots
- Potential DER measures in the future
- Customer-sited solar
- Dispatchable standby generation

G.2.1.1 Flex Load Programs and Pilots

The first group of VPP resources includes all programs, pilots and demonstrations which are currently existing or in the pipeline of near-term implementation. These are as follows:

- Residential Smart Thermostat is a direct load control program which is aimed at residential HVAC systems, utilizing smart thermostats to manage and optimize energy usage.
- Peak Time Rebates (PTR) is a behavioral/manual DR offering which incentivizes residential customers to reduce energy consumption during peak times without the need for up-front equipment investment.
- Time of Day (TOD) is a residential time-varying rate offering designed to encourage customers to shift their energy use from on-peak hours to off-peak times.

- Energy Partner on Demand Schedule 26 targets large commercial and industrial customers, providing incentives for custom load curtailment strategies and event-based energy shifts.
- Energy Partner Commercial Thermostats Schedule 25 is a direct load control offering which targets small and medium-sized businesses, using smart thermostats to manage HVAC loads.
- Multi-family Water Heater (MFWH) targets multi-family residences to control water heater loads.
- Smart Charging, which is a pilot focused on residential EV charging, enables customers with eligible electric vehicles or Level 2 chargers to participate in managed charging. It allows to temporarily reduce or shift charging during periods of peak electricity demand to support grid reliability and reduce system costs.
- Commercial EV Charging demonstration is being planned to test several recommended strategies for Commercial Managed Charging with the goal of load management.
- Energy Storage connects customer-owned home battery systems allowing charging or discharging of participating batteries to shift load, reduce system costs, and support grid reliability.

G.2.1.2 Potential DER Measures in the Future

Because the IRP evaluates resource needs over a 20-year planning horizon, the analysis includes not only DER measures that are currently offered but also emerging technologies and resource opportunities that may be considered through future demonstrations, pilots, or program offerings. Accordingly, this IRP assesses a broad range of future-looking DER measures, including both resources with relatively higher technical potential based on current market adoption trends and more nascent technologies that may become viable over the planning horizon. The future-looking DER measures are listed below.

- Energy Partner Z—Cold Storage
- Multi Family Ducted Heat Pump
- Connected Air-Source Heat Pump
- Connected Smart Electric Resistance Water Heater
- Energy Partner—Agriculture
- Microgrids
- Fleet Charging (DCFC)
- Single Family Water Heating
- Other Potential DR

G.2.1.3 Customer-Sited Solar

The third broad group consists of behind-the-meter rooftop solar installations at customer sites. PGE offers net metering to applicants interested in offsetting their electricity consumption as an existing retail service customer of PGE.

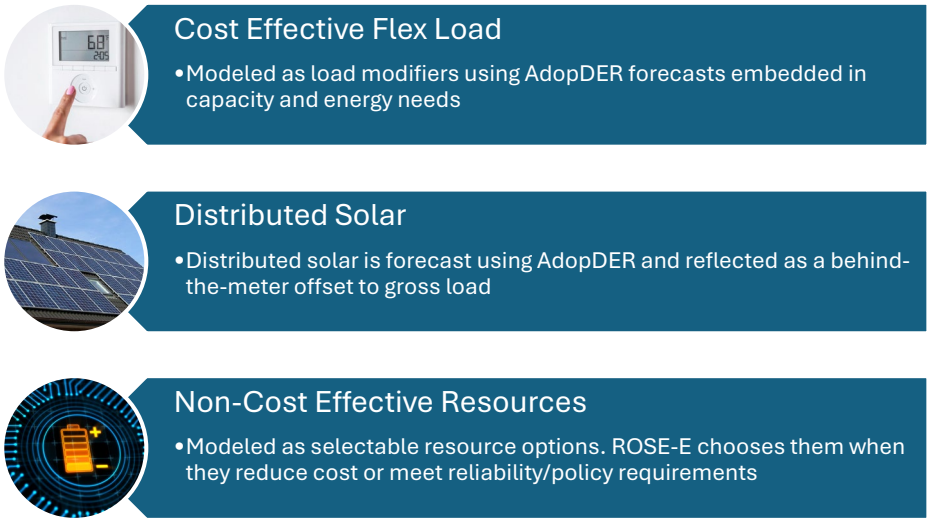
G.2.1.4 Dispatchable Standby Generation

The fourth broad group consists of Dispatchable Standby Generation (DSG) which is a program that allows eligible customer-sited standby generators and batteries to support grid needs when they are not needed for the customer's own reliability requirements. The DSG program partners PGE with commercial and industrial customers who have emergency standby generation or batteries greater than 250 kW. Resources participating in DSG are upgraded, enabled, and operated to meet PGE's dispatchability, environmental, telemetry, and operational requirements. This makes DSG a dependable source of customer-sited capacity within PGE's broader VPP portfolio. Reciprocating diesel engines normally power these standby generators. The program helps to fulfill PGE's NERC requirement for reserves to respond to local region reliability impacts. By utilizing DSG for operating reserves, PGE can fully utilize clean energy resources for daily power needs instead of needing to reserve a portion for reliability needs.

G.2.2 Historical Treatment of VPP Resources Within IRP Analysis

Historically, IRP analyses have focused primarily on evaluating traditional supply-side resources to identify a least-cost, least-risk preferred portfolio. VPP represents a portfolio of diverse DERs with varying operational characteristics, performance capabilities, and costs, and currently there is no standard methodology for precisely modeling these resources within IRP. Most of the VPP resources (like cost effective flex load resources) were historically aggregated to be included as an offset to the gross load.

Figure 110. Historical Treatment of VPP Resources



G.2.3 Modeling Approach

Given the significant growth and maturation of PGE's VPP portfolio, it is important that the Company's planning framework more explicitly reflects the contributions of these resources and evaluates them alongside supply-side resource options. For that purpose, the 2026 CEP/IRP incorporates a more granular representation of individual VPP resource types within the core IRP modeling framework towards constructing its least-cost least-risk portfolio.

In this first iteration of VPP model integration within IRP, the Flex Load and DSG resources are being made available as resource options for selection by the optimal capacity expansion tool (i.e. ROSE-E). It is important to remember that there are 18 different Flex Load resources that are being included in this analysis. Modeling and evaluating each of these separately would add significant amount of computational and resource burden to the resource adequacy modeling, portfolio construction and portfolio evaluation steps. After considering different options we determined that instead of looking at the VPP resource as a single aggregated resource or as 18 individual resources, the best solution would be to create multiple bins with logical grouping of resources.

We have developed five core VPP Flex Load resource bins. We have segmented each bin into summer and winter sub-bins to account for any differences in capacities and load shapes between the two seasons. The resources are grouped based on similar dispatchability, hourly load shapes, and PGE Program consolidation. Existing PGE Programs and pilots are covered in bins 1-3. Bin 1 consists of large MW dispatchable PGE Programs, bin 2 consists of behavioral PGE Programs and bin 3 includes other PGE programs and pilots. Future-looking DER measures are included in bins 4 and 5. High technical/market potential and stretch DER measures are included in bins 4 and 5 respectively. For each bin we have two ELCCs: one for summer and one for winter. Within some of the bins there may be resources that have different call limits. In this first iteration the focus has been on developing a model such that these five bins of resources are available to contribute to the system on days with the greatest load.

Figure 111. Five VPP Resource Bins

Bin1: Large MW Dispatchable PGE Programs	Bin 2: Behavioral PGE Programs	Bin 3: Other PGE Programs/Pilots	Bin 4: High Technical / Market Potential	Bin 5: Stretch/Emerging
• Residential Smart thermostat • Energy Partner – Schedule 26	• Peak Time Rebates • Time of Day	• Smart Charging (residential) • Commercial EV Charging • Eenergy Partner – Schedule 25 • Multifamily Water Heaters • Residential / Non-Residential Storage	• Energy Partner – Cold Storage • Multifamily Ducted Heat Pump • Connected Air-Source Heat Pump • Connected Smart Electric Resistance Water Heater	• Energy Partner - Agriculture • Microgrids • Fleet Charging (Direct Current Fast Charging) • Single Family Water Heating • Other Potential Demand Response

G.2.4 Assumptions

In this first iteration of granular modeling of VPP within the IRP, the VPP resources are modeled as capacity-only resources. Forecasted incremental capacities, simulated load impact shapes and

estimated levelized net costs are three critical pieces of data. The incremental capacities by which each bin (i.e. 5 bins of VPP Flex Load) or broader category of VPP resource (i.e. thermal DSG) are forecasted to be adopted each year over the planning horizon provides the maximum capacity that can be selected each year for that individual or grouped resource. For each bin of VPP Flex Load there can be difference in the capacity and load impact shapes between summer and winter and hence seasonal capacities and shapes are provided to capture those details. Because VPP resources provide different types of value, PGE evaluates the portfolio using a benefit-cost framework rather than relying only on enrollment, participation, or technology adoption metrics. This is important because the benefits of demand response programs may include avoided capacity costs, avoided or deferred transmission and distribution investment, avoided energy costs, improved operational flexibility, reliability value, and customer benefits. However, in the model avoided capacity costs are removed when calculating the levelized net costs since ROSE-E already assesses the capacity benefits provided by each resource option during portfolio construction and evaluation.

There are two (2) main steps in the model that are related to the integration of VPP resource. First is the computation of the ELCCs of these resources by SEQUOIA. Second is the determination of how much of the forecasted capacity of each broad resource option offered to ROSE-E is being selected as part of the different scenario specific portfolios.

It is important to note that the IRP model is not constrained to selecting the entire capacity that is estimated to be achievable for each bin of VPP Flex Load or DSG. ROSE-E evaluates available capacity, ELCC and cost of each binned resource alongside other supply-side resources to determine how much capacity of each binned resources should be selected to construct least-cost least-risk portfolio.

Additional information related to the modeling of VPP Flex Load and DSG is presented in Appendix Section H.1.

G.2.4.1 Flex Load

PGE uses AdopDER to forecast adoption of different DR measures. Low, reference and high DER adoption scenarios are modeled to estimate the different values of capacity of each measure that are adopted by customers over the planning horizon. The AdopDER model is a comprehensive site-level simulation model that allows for a hybrid top-down and bottom-up modeling approach to estimate locational, hourly annual load impacts from the co-adoption of 50+ DERs and electrification. AdopDER is built in Python and forecasts DER adoption dynamically, with stochastic influences where appropriate, under different conditions. PGE has considered both programmatic adoption (which simulates measure adoption through PGE programs), and market adoption (which simulates naturally occurring measure adoption without program intervention).

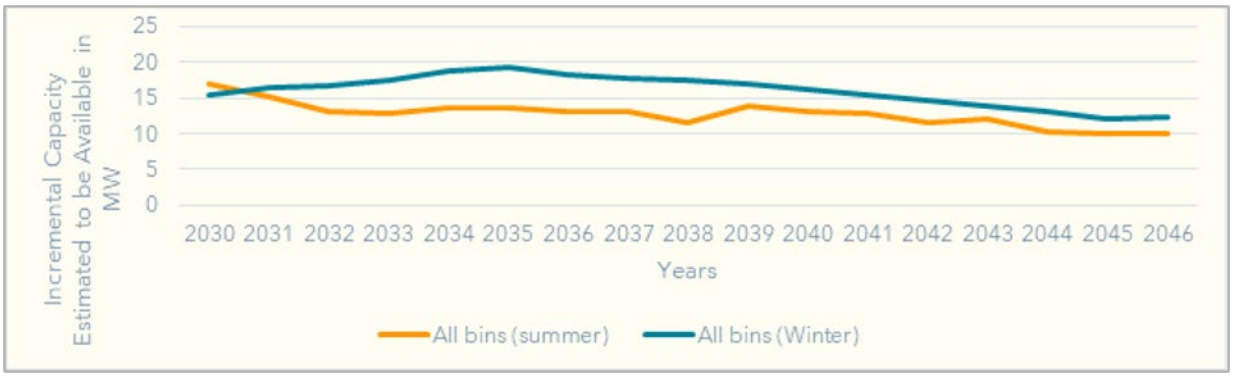
PGE simulated market adoption trends using a blend of macro-level forecast and market demand models and then calibrated these to the granular site-level stock turnover model using available knowledge of customer characteristics. Planning generates bottom-up customer DER additions based on detailed information across a range of potential areas of activities which include new sources of demand (such as increased use of central air-conditioning, electric vehicles), DER interconnection applications, local development policies, legislative changes or code changes, and

any planned development or redevelopment activity spurring from local community or business development plans.

The AdopDER model determines the adoption and the associated load impacts of different types of DER measures that are part of VPP portfolio, and the associated real levelized net costs and benefits.

- Incremental Capacity Availability: Load impacts are informed by evaluation-based performance assumptions, with studies conducted by firms such as Resource Innovations, which simulate DR events and estimate resulting customer load reductions. Average aggregated hourly load reduction estimates have been determined for each VPP resource both seasons, which have been combined to determine the seasonal impact shapes for each bin. These shapes are used to determine ELCC values needed by ROSE-E.

Figure 112. Incremental Capacity in MW



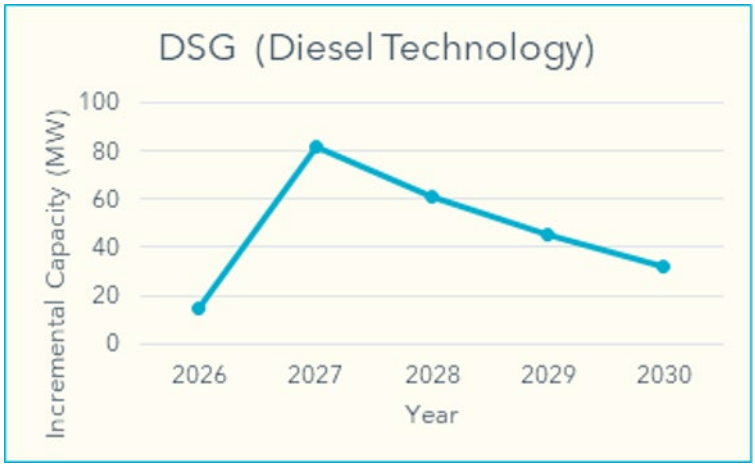
- Costs: Levelized net costs are estimated for each of the seasonal VPP bins. For the existing VPP programs for which PGE has actual cost and benefit data as part of their cost effectiveness workbooks, real-world estimates were used to determine the present real levelized net costs. For VPP measures which are not part of the existing programs, real levelized net cost estimates were used, provided by AdopDER.

G.2.4.2 DSG

PGE uses actual data and forecasts from the Programs group to determine the incremental capacity additions and fixed costs associated with DSG over the planning horizon.

- Incremental Capacity Availability: The following figure shows the incremental capacity of thermal technology-based DSG (in MW) available up to 2030. Incremental DSG capacities are forecasted and made available to ROSE-E for selection in portfolio along with levelized costs of the incremental capacity additions. No new DSG units are assumed to be added after 2030. DSG growth will require regular engagement from PGE's environmental compliance, partially due to diesel emissions criteria at the Oregon Department of Environmental Quality (ODEQ).

Figure 113. Diesel Incremental Capacity in MW



- Costs: Levelized net costs are estimated for each of the DSG utilizing actual cost data as part of their cost effectiveness workbooks.

G.2.5 Future Capability Development Needed

For fully realizing the immense value that VPP can provide, PGE would need continued investment in enabling technologies, including DER orchestration platforms, communications infrastructure, and advanced controls capable of aggregating customer-sited resources into scalable virtual power plant (VPP) capabilities. Today, the VPP already provides essential grid services when they are most needed such as load reduction during peak load events and contingency and frequency reserves for grid disruptions. Development and maturation of VPP capabilities will unlock more benefits for customers and the system overall. This will help the Company balance affordability, reliability, customer choice, and decarbonization objectives while building a more flexible energy system.

G.3 Community-Based Renewable Energy

Community-Based Renewable Energy (CBRE) is defined in HB 2021 to generally include renewable resources designed to deliver local, equitable, and resilience-oriented benefits, not solely least-cost energy. CBREs are not a replacement for utility-scale renewables, but a complementary resource class focused on community benefit. They are not defined by the size of project and can be large or small. CBREs can also have a range of locations, be on or off PGE's system, and can also be front-of-meter projects (as represented in IRP), as well as behind-the-meter customer solutions. Representation of CBREs in IRP captures a view, but not a complete picture of CBREs. Due to the long-term nature of planning, here, the aim has been to represent these kinds of projects through model cost-optimization and a view that could be considered a more holistic system-considerate economic approach to CBRE deployment, rather than trying to capture the details of specific project or participant benefits. However, as noted, real CBRE deployment can be considered a range of things and PGE is considering all options through additional means beyond IRP and planning. This document focuses on the CBRE approach in planning.

The 2023 CEP/IRP represented PGE's first systematic integration of CBREs into long-term planning. During that last planning cycle, PGE conducted a Community Lens Potential Study to estimate feasible CBRE capacity aligned with HB 2021 definitions. The results were leveraged into proxy CBRE assumptions for IRP, though the method emphasized screening potential and did not include project-specific siting or cost certainty.

Due to the range of cost and operational data needs to represent proxy resource options for 20 years in IRP, most resource assumptions come from other modeling work for consistency and transparency, rather than trying to compile a range of real-world data sets that may have data gaps or differences across resource options. Deviating from this approach is how PGE represented proxy CBREs in this CEP/IRP. This is because the 2025-2026 CBRE RFO provided important real-world market insight to advance PGE's community-focused work. It enabled bidders to submit project proposals and associated costs for resource strategies intended to support targeted community benefit outcomes. Projects were evaluated by PGE, as well as the CBIAG, who scored based on metrics beyond cost including planning and milestones, community partnership, financing, and other benefits.[173] The OPUC ultimately acknowledged a final shortlist consisting of battery storage-oriented CBREs totaling approximately 50 MW online by 2030. PGE compared relative procurement costs of shortlisted CBRE projects against comparable utility-scale resources in the May 2026 RoundTable,[174] providing a directional estimate of the incremental additional procurement costs associated with pursuing resource strategies aligned with targeted community benefit outcomes.

This real-world data on CBRE technology, potential, and costs, differs meaningfully from PGE's high-level assumptions in the 2023 CEP/IRP and Update. Through bids and the RFO process, PGE learned that the amount of CBRE capacity available, especially in the near-term, is likely lower than previously assumed, and associated costs are likely higher. The following subsections describe in more detail the assumptions for the proxy CBRE resource option in this CEP/IRP. The RFO results used here for planning helped refine and validate the technology option, feasibility, and pricing, but were not designed to maximize near-term CBRE MWh or MW scale. Exploring more prescriptive future solicitations to identify additional CBRE capacity potential may still occur outside the modeling and planning processes, though gains may be less scalable and more bespoke, especially under current interconnection and cost headwinds, and therefore were not attempted to be reflected here in the modeling for this planning cycle.

G.3.1 Proxy CBRE Technology

The 2023 CEP/IRP, informed by screening potential, assumed approximately 155 MWa of CBREs by 2030, with roughly 100 MWa of this represented by microgrid solar plus storage resources and the remainder standalone solar. The RFO provided important market intelligence regarding project maturity, developer participation, pricing and financing feasibility to better inform the technology options for modeling based on actual procurement conditions. Most bids were for solar plus storage projects. This helped refine PGE's approach for this CEP/IRP to focus one proxy CBRE

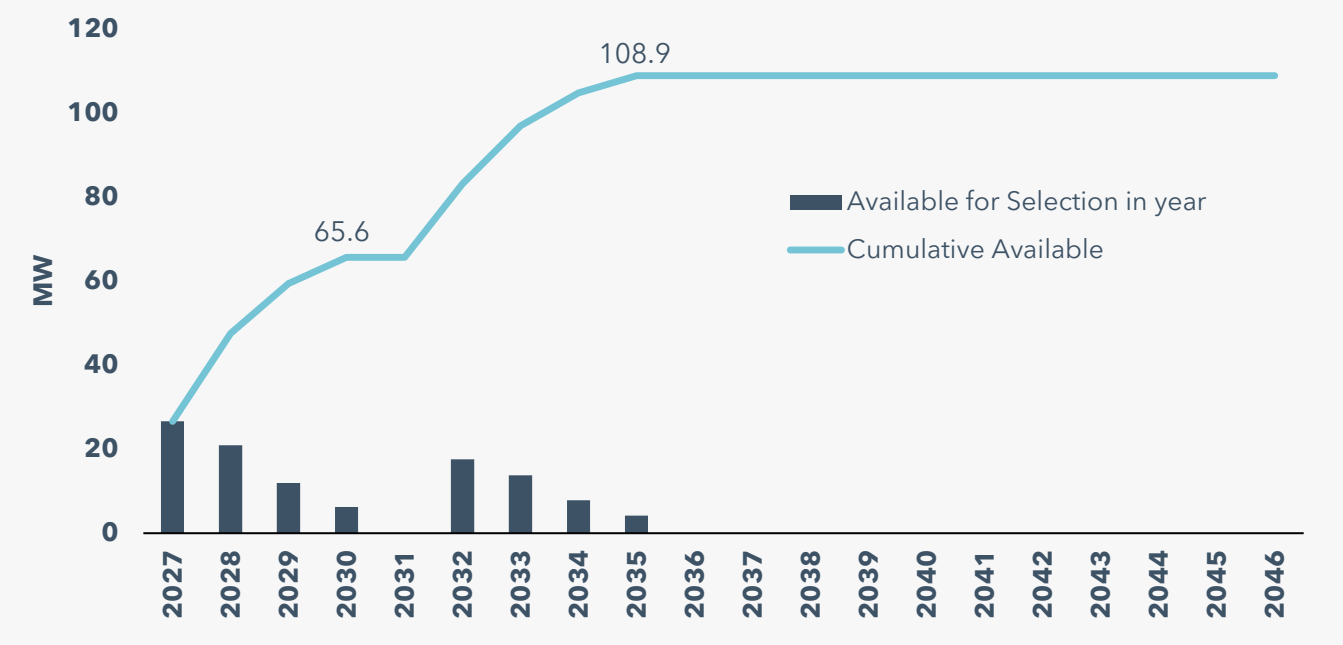
[173] OPUC Order No. 26-147, https://apps.puc.state.or.us/orders/2026ords/26-147.pdf.
[174] Appendix Section C.2.7.

resource option available in portfolio analysis to only represent a microgrid resource of solar paired with storage, rather than the multiple CBRE options from the 2023 CEP/IRP and Update. A solar plus storage project type is representative of viable bid data to inform this analysis and represents projects of interest as they would better support resilience compared to other resource types such as standalone solar.

G.3.2 Proxy CBRE Potential

Viable, complete responses in the RFO for solar plus storage projects provided information on project potential materially below the potential assumed in the 2023 CEP/IRP, indicating that the previous near-term assumption for modeling was likely over-stated actual market conditions. Rather than maintaining the earlier assumption, the approach in this CEP/IRP grounded the proxy CBRE potential in RFO data, finding up to 65.6 MW available for deployment through 2031. After this time, forecasted potential available for the modeling was informed by proxy assumptions for the next phase of deployment with CBRE potential grown by roughly half of the recent historical deployment activity of real QF and Community Solar projects in PGE service territory. This approach for growing the proxy CBRE capacity available in modeling over time incorporated observed market limitations while still recognizing that in the future, more projects with lower complexity and broader procurement opportunities than identified through the RFO may become available. The proxy CBRE capacity made available for selection in portfolio analysis is shown in Figure 114. For this CEP/IRP, a maximum of up to 108.9 MW of proxy CBRE capacity may be selected in each portfolio scenario, as informed by costs, needs, policy, and other model optimization constraints.

Figure 114. Capacity of Proxy CBRE Resource Available for Selection in IRP



G.3.3 Proxy CBRE Costs

The average cost across available bid data from the RFO compared to proxy utility-scale resource assumptions informed the proxy CBRE cost in this CEP/IRP. Due to the interest in CBREs, PGE

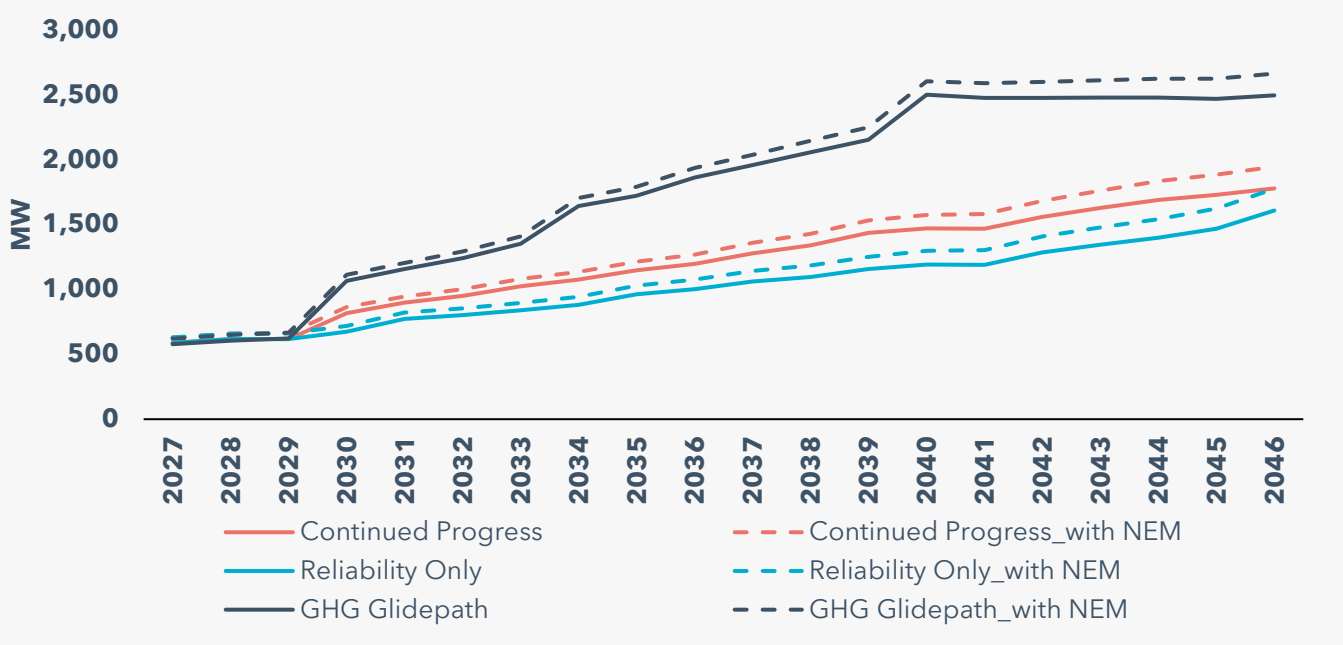
incorporated assumptions in modeling for resource CBIs, or rCBIs, in all portfolio analysis and scenarios. Resource CBIs can be used to attempt to find a way in planning to understand how different CBRE cost assumptions might result in greater deployment of these kinds of projects. Changes to the cost assumptions, namely reducing the market-informed proxy CBRE cost for modeling by assuming some quantity of rCBIs, highlights the potential that on average, real-world bid costs may need to come down to make these kinds of projects more competitive in the broader procurement market. The downward adjustment to levelized costs for proxy CBREs in all scenarios assumed a value of rCBIs that brings the cost (originally informed by RFO bid data) down to a level like utility-scale solar, which in the modeling encourages greater selection of this resource in portfolio analysis. See Appendix Section D.3 for more detail on this rCBI approach to CBRE cost assumptions.

G.4 Small Scale Renewables

According to ORS 469A.210, most Oregon utilities must contribute to a collective small-scale renewable requirement: that 10% of electrical generating capacity must come from renewable resources smaller than 20 MW or qualifying biomass generators by 2030. For planning purposes, PGE assumes the need to meet 10% of PGE installed capacity with SSRs by 2030 and each following year of the planning horizon.

Estimating the Small-Scale Renewables (SSR) need is a function of the nameplate capacity of existing resources in PGE's baseline portfolio plus new resources added through capacity expansion modeling, not including any batteries or other storage, nor customer-sited renewables like NEM. Figure 115 shows the SSR need for select scenarios. Since a growing amount of increased installed capacity (as VERs) is needed in the HB 2021-compliant scenario, the SSR target is higher since it is a function of total installed capacity.

Figure 115. Total SSR Compliance Requirement by Year



Certain resources contribute toward the SSR requirement, including several ongoing resource acquisition pathways such as the Oregon Community Solar Program (CSP) projects, qualifying facility (QF) development, and CBREs.

Existing baseline resources that contribute to the SSR requirement include:

- CSP capacity in 2030: 46 MW
- QF capacity <20 MW under contract to PGE in 2030: 269 MW
- Other SSR-eligible projects owned or contracted by PGE in 2030: 54 MW
- Customer solar: described below

Per OPUC Order No. 21-464,[175] it is unclear whether net metered (NEM) renewables can 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 contributed to the value of distributed solar to PGE's system. PGE's SSR compliance assessment considers NEM solar as a sensitivity. Customer solar deployment forecast results come from AdopDER with this distributed PV adoption summarized in Section 6.2.2.3. This is included as contributing to the SSR requirement in the sensitivity with NEM, with a total of 461 MW deployed by 2030.

Proxy new resources that contribute to the SSR requirement include:

- CBRE acquisition forecast for 2030,[176] renewable portion only (excludes battery): 27 MW in GHG Glidepath; 0 MW in Continued Progress; 0 MW in Reliability Only
- SSR proxy resource: described below

A proxy supply-side resource was added to represent the range of small-scale renewable (SSR) resources that may be required to help PGE contribute to the 10% small-scale renewable requirement. The inclusion of this SSR proxy allows the requirement to be accounted for in portfolio analysis.

The 10% requirement uses only one metric (i.e., 20 MW or less in size) and does not incorporate community benefits[177]. The purpose of the SSR proxy resource is strictly to analyze compliance with the statutory requirement; consequently, PGE chose to design the resource to represent projects on the upper end of the 20 MW size limit, which are not as costly as smaller community-scale projects. Smaller-scale projects are already considered in portfolio analysis through the lens of CBREs (described in the preceding subsection).

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 fixed cost of the SSR resource is based on the

[175] See OPUC Order No. 21-464, resolution 3c, available at AR 622 with corrected signature blocks_encrypted_.pdf.
[176] See Chapter 7 for more on new resource selection in portfolio analysis results.
[177] 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.

Christmas Valley solar proxy resource, 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. To account for this size-cost dynamic, the $/kW fixed costs of the SSR resource were inflated by 8% 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. In alignment with the 2023 CEP/IRP Update, analysis in Berkeley Lab's "2024 Utility-Scale Solar, 2024 Edition" report was used to estimate this 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 8% lower capex costs, with a weighted mean of $1.18/W.[178]

After accounting for the qualifying existing baseline resources and proxy new resources (CBREs), any remaining gap to the estimated SSR compliance requirement is filled in by the SSR proxy resource in the analysis described in Section 7.8, which summarizes the SSR need and build cost impacts of compliance.

G.5 Supply-side Resource Options

This appendix provides information summarizing the operational and cost attributes of various power generation and storage technologies. The technologies considered include:

- Onshore wind
- Offshore wind
- Solar photovoltaic
- Battery energy storage
- Co-located, hybrid solar and battery energy storage
- Co-located, hybrid wind, solar, and battery energy storage
- Long-duration battery energy storage
- Pumped hydroelectric energy storage
- Geothermal
- Nuclear-powered generation
- Natural gas-fueled resources

G.5.1 Sources of Information

G.5.1.1 Resource Costs and Operating Parameters

As discussed in Section 3.2, the outlook for resource costs is subject to changing geopolitical and supply/demand dynamics. In recent IRPs, PGE has relied almost exclusively on publicly available resource cost assumptions; specifically, the Annual Technology Baseline (ATB) produced by The National Laboratory of the Rockies (NLR) and research supporting The Energy Information

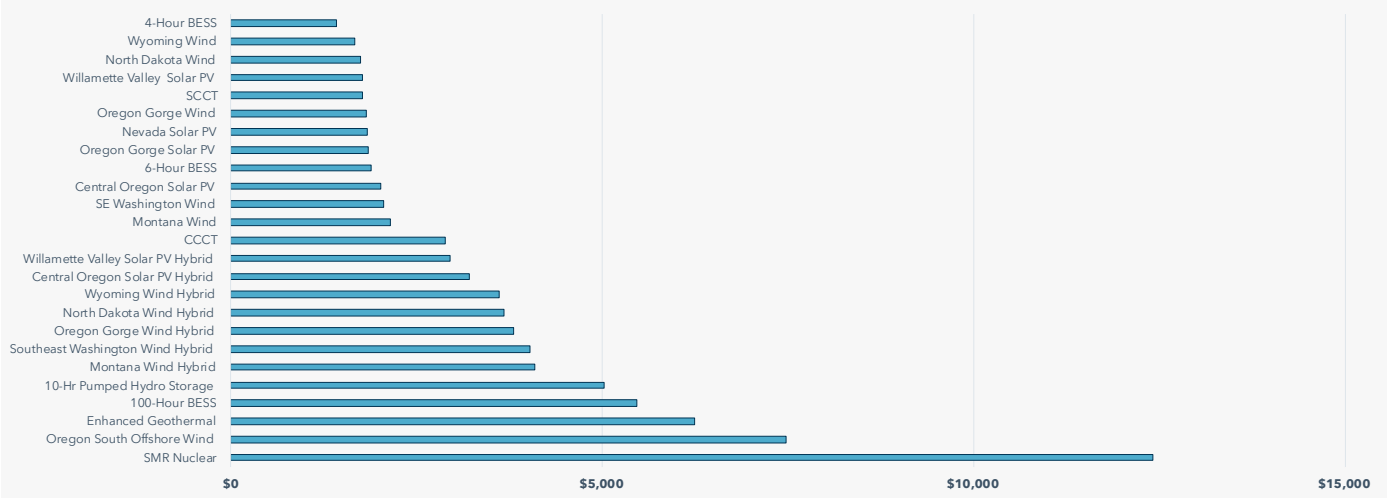
[178] Berkeley Lab's "2024 Utility-Scale Solar, 2024 Edition" report can be found at http://utilityscalesolar.lbl.gov.

Administration's (EIA) Annual Energy Outlook 2025 (AEO). Market observations and feedback from stakeholders in the current IRP process prompted PGE to look for alternative sources of information.

Supply-side resource capital and operating expenditures are sourced from Wood Mackenzie and 1898 & Co. unless otherwise noted. PGE consulted the Wood Mackenzie North America Levelized Cost of Electricity (LCOE) 2025 Report and associated data. For additional information regarding energy storage resources, PGE commissioned a report from 1898 & Co. covering lithium-ion, non-lithium-ion long duration, and pumped hydroelectric. To supplement this information, PGE continues to rely on publicly available sources including the revised 2024 Annual Technology Baseline produced by The National Laboratory of the Rockies (NLR ATB) and the Sargent & Lundy "Capital Cost and Performance Characteristic Estimates for Utility-scale Electric Power Generating Technologies" produced for The Energy Information Administration's Annual Energy Outlook 2025 (EIA AEO).[179]

Resulting all-in overnight capital costs for proxy new resources under a Reference case scenario in this IRP are summarized in Figure 116 below.

Figure 116. Summary of proxy resource overnight costs (2026$/kW, hypothetical 2032 COD)



Low, average, and high resource cost scenarios are primarily driven by economies of scale and supply chain integration (procurement), technological maturity (technology), and geographic alignment (geography).

These scenarios are reflected in the various components of proxy resource fixed costs presented in the remainder of this Appendix.

Low Capital and Operational Costs (Optimized)

[179] EIA AEO 2025. "Capital Cost and Performance Characteristic Estimates for Utility-scale Electric Power Generating Technologies." Prepared by Sargent & Lundy. Available at: https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf

Procurement - Large-scale procurement drives economics of scale; Optimal timing; Strong developer / OEM / supply chain relationships.

Technology - Innovative business models; Large, integrated portfolios benefit from digitalization and reduced labor costs, leading to significant optimization and predictive maintenance.

Reference Capital and Operational Costs

Procurement, technological, and geographic development continues in-line with industry trends.

High Capital and Operational Costs (Constrained)

Procurement - Lower procurement volumes result in higher per-unit costs; Sub-optimal timing.

Geography - Potential geographical challenges.

Technology - Smaller, geographically dispersed portfolios with slower digitalization, resulting in higher labor costs.

G.5.2 Renewable Resources

G.5.2.1 Wind and Solar PV Generation

PGE uses NLR's System Advisor Model (SAM) to produce simulated hourly generation profiles for each wind a solar PV site assessed in the IRP. According to NLR, SAM is a "free desktop application for techno-economic analysis of energy technologies."[180] The application provides access to weather data and detailed options for defining the system design parameters. An hourly generation profile is simulated in SAM for each year of weather data for each wind or solar site of interest. For wind resources, data for 2007-2013 is used for these simulations. Solar data for 1998-2024 is used to simulate solar PV performance. These profiles are used as inputs to Sequoia. For energy modeling in Aurora, the hourly shapes for representative years are used. These representative profiles for each site are created by:

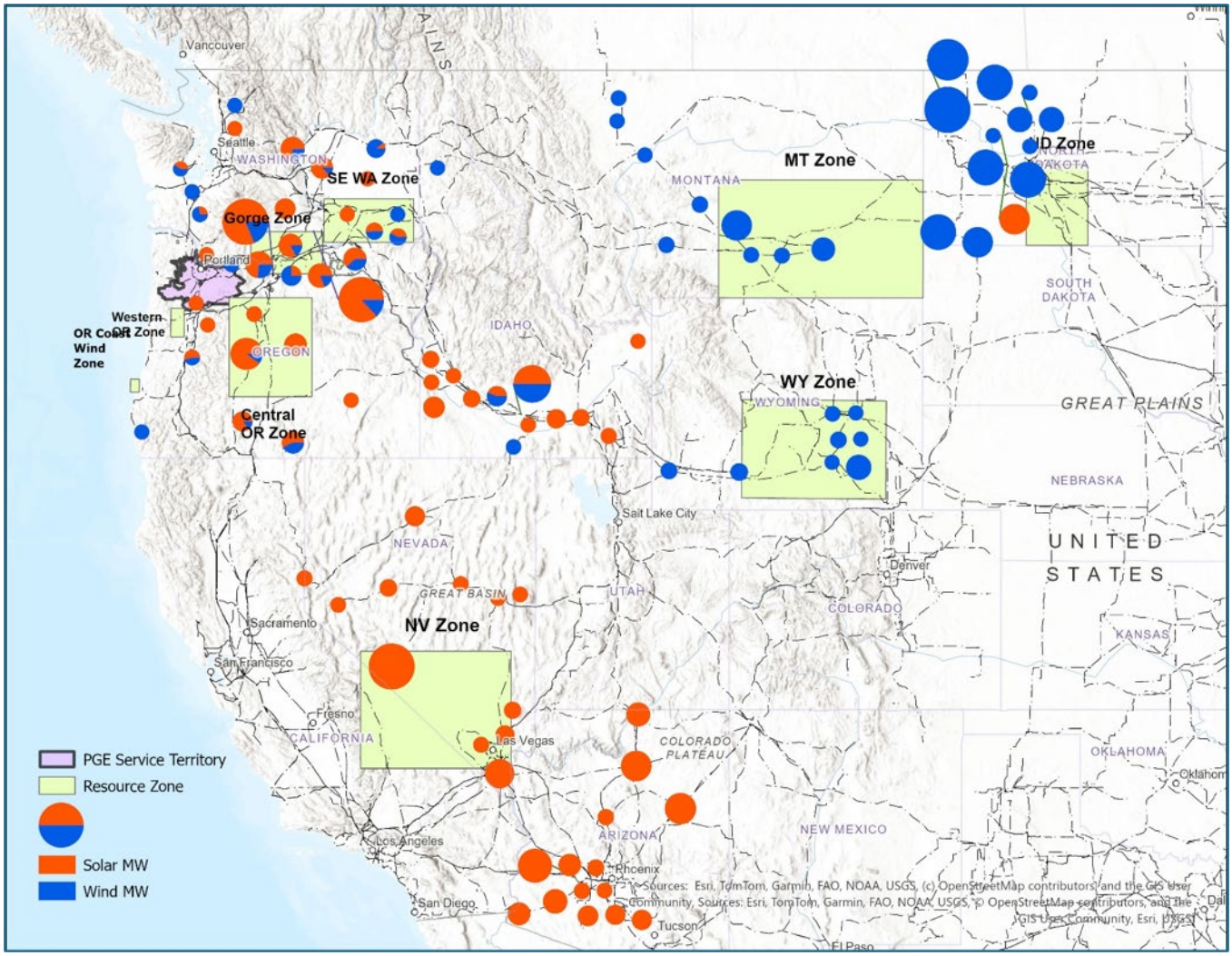
1. Simulate hourly shapes for each year with available weather data (e.g., for 10 years of weather data, create 10 simulated shapes each comprising 8,760 hours).
2. Compute the monthly average capacity factors across the data from step #1 (average across 10 years each month).
3. For each month, choose the hourly data from the year that most closely matches the monthly average capacity factor computed in step #2 (if in January, for example, the year five capacity factor is nearest to the average from step #2, the representative shape will use the year five hourly data for January).
4. Use the hourly data from each month selected in step #3 to create the representative shape.

This process results in shapes that closely match the annual capacity factors averaged across the available weather data while maintaining the variability of the underlying hourly data. Using publicly available data from NLR is an attempt to enable transparent and comparable analysis across resources in the IRP. The resulting energy shapes and capacity factors from this analysis will differ

[180] https://sam.nlr.gov/

from those experienced by resources constructed in the future. Resource developers participating in a competitive procurement process will perform detailed analyses of specific projects to optimize resource economics (cost and performance) with respect to geographic location and resource configuration, among other factors. Figure 117 illustrates the areas in which wind and solar resources are investigated for this IRP as well as the interconnection mix.

Figure 117. Wind and Solar Areas of Investigation



G.5.2.2 Onshore Wind

Technology Description

Wind turbine generators convert kinetic wind energy into electrical power. The horizontal-axis three-bladed design is the most ubiquitous type of wind turbine used for electric power generation. Lift is generated when wind flows around the turbine blades, resulting in rotation. The blades are connected to a central hub and drivetrain that turns a generator inside the nacelle, which is the housing positioned atop the wind turbine tower.

Commercial Status

According to data published by Lawrence Berkeley National Laboratory (LBNL), installed wind capacity in the United States has averaged a 6% annual growth rate from year end 2020 through 2024 (the last year for which data are reported). The growth of wind in the western US has slightly trailed the national average, at approximately 5.4% annually. At the end of 2024, wind generating capacity in the country totaled nearly 155 GW.[181] 3,650 MW SunZia project (New Mexico) is expected to come online in 2026.

Key aspects of wind turbine generator designs have increased every year since 2020 as well. The average rated capacity of new turbines in 2024 was 3.5 MW, a nearly 27% increase from the average capacity in 2020. Likewise, the blade rotor diameter of new turbine installations has grown by more than 9% to 136.7 meters and hub heights rose to 106 meters or nearly 18% higher than the 2020 average.[182]

Resource Characteristics

Five proxy wind resources are modeled with identical turbine specifications and layouts. These sites in Oregon, Montana, Washington, North Dakota, and Wyoming are summarized in Table 53 below.

Table 53. Summary of Onshore Wind Sites

Site	Lat.	Long.	IRP CF%
Oregon Gorge	45.65	-120.63	37.1%
Southeast Washington	46.41	-117.84	38.9%
Eastern Montana	46.81	-106.22	40.7%
Center, North Dakota	47.17	-101.33	42.4%
Casper, Wyoming	43.04	-105.56	42.4%

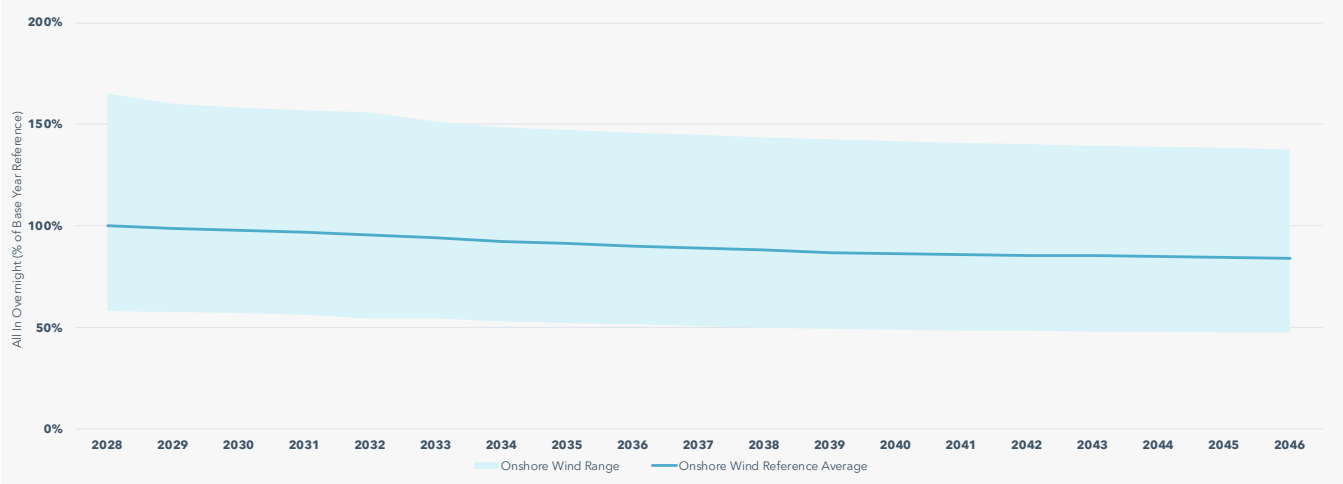
Four point five (4.5) MW turbines are modeled in SAM using eight years of weather data, as mentioned previously. The hub height is 105 meters, and rotor diameter is 150 meters. Maintaining a consistent resource configuration at the five sites focuses any analysis on wind resource variations rather than attempting to optimize each site's design. It is expected that developers in the marketplace will use their expertise to design optimal resources for any specific location. The layout arranges turbines in eight rows of eight turbines with eight-rotor diameter spacing.

[181] Lawrence Berkeley National Laboratory. "Land-based Wind Energy Technology Data Update: 2025 Edition," available at: https://eta-publications.lbl.gov/sites/default/files/2025-08/data_file_land-based_wind_energy_technology_update_2025_edition.xlsx
[182] Lawrence Berkeley National Laboratory. "Land-based Wind Energy Technology Data Update: 2025 Edition," available at: https://eta-publications.lbl.gov/sites/default/files/2025-08/data_file_land-based_wind_energy_technology_update_2025_edition.xlsx

Forward Capital Cost Curve

The projection of future capital costs for onshore wind resources is presented in Figure 118.

Figure 118. Onshore Wind Capital Cost Trajectory



G.5.2.3 Offshore Wind

Technology Description

Electricity generation from offshore wind is conceptually similar to that of onshore wind. The primary difference is that the wind plant is in offshore waters allowing access to a potentially diverse and more energetic wind resource. The offshore wind technology considered for the Oregon coast is of the "floating" type. These floating installations do not anchor the tower directly to the ground but rather employ a structure that floats in the water and is anchored to the seabed. The application of fixed bottom vs. floating technology is generally dictated by the depth of the water, with water more than 60 meters typically requiring the use of a floating structure. According to NREL research, water depths are greater than 60 meters in 97% of the water on the Outer Continental Shelf (OCS – administered by the federal government) off the Oregon coast, dictating the use of a floating technology as opposed to fixed-bottom.

Commercial Status

Federal policies impacting U.S. offshore wind development have undergone drastic changes under the current administration. In 2025, an executive memorandum withdrew the federal lands of the outer continental shelf (OCS) from leasing.[183] Later that year, the Bureau of Ocean Energy Management rescinded Wind Energy Area designations from 3.5 million acres or federal water, including from sites along the OCS of Oregon. This action halted the development of offshore wind projects in federal waters.[184]

[183] https://www.congress.gov/crs-product/LSB11402
[184] https://www.boem.gov/renewable-energy/lease-and-grant-information

Several offshore wind developments off the east coast of the US are expected to come online in 2026 and 2027. 1.5 GW capacity is expected to begin generating in 2026, including:[185]

- 800 MW Vineyard Wind 1 project (offshore Massachusetts) and
- 715 MW Revolution Wind (offshore Connecticut and Rhode Island).

An additional 4.4 GW of capacity is expected to be online in 2027:

- 2.6 GW Coastal Virginia (Virginia)
- 0.9 GW Sunrise (New York)
- 0.8 GW Empire (New York).

Operational Characteristics

PGE's offshore wind modeling focuses on a southern Oregon site offshore between Coos Bay and Brooking.

PGE's analysis of the wind resource utilizes an NREL dataset covering the 20 years 2000 through 2019 ("OR-WA20" dataset).

The generic offshore wind resource in the IRP is modeled using 15 MW turbines with 248-meter rotor diameters at hub heights of 150 meters. The turbine arrangement is based on a seven-rotor diameter spacing.

Table 54. Oregon Offshore Wind Operational Characteristics

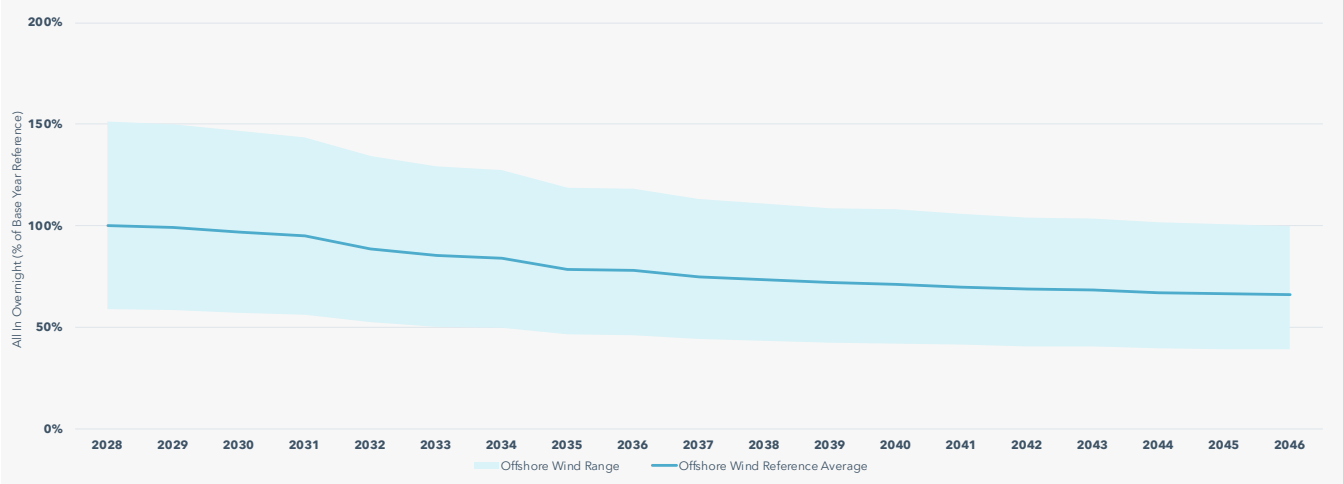
Site	Lat.	Long.	IRP CF (%)
Oregon South	42.69	-124.84	55.2%

Forward Capital Cost Curve

The projection of future capital costs for the proxy offshore wind resource is presented in Figure 119.

[185] 2025 Form EIA-860 Data Early Release - Schedule 3, 'Generator Data' (Operable Units Only). https://www.eia.gov/electricity/data/eia860/

Figure 119. Offshore Wind Capital Cost Trajectory



G.5.2.4 Solar Photovoltaic

Technology Description

Solar photovoltaic (solar PV) converts light from the sun into electrical energy. Cells generate direct current (DC) electrical energy. This conversion occurs within a cell; multiple cells are connected within a module. The total quantity of modules is the array. The power rating of the array is the DC capacity of the resource. The modules in the array can be either fixed at a given angle or employ a system to control the array tilt in one (1) or two (2) directions to track the sun. The orientation of the modules is typically defined with respect to azimuth (e.g., zero if facing north, 180 if facing south).

Because utility-scale generation must interface with the alternating current (AC) grid, inverters are utilized for power conversion from DC to AC. The relationship of the array's DC capacity to the inverter's AC rating is referred to as the inverter load ratio (ILR). For example, an ILR of 2.0 means the DC capacity of the array is double the AC rating of the inverter. With this relationship, during periods of peak irradiance the array will have the potential to generate at levels higher than the inverter's rating; the inverter will limit the total output and this excess energy from the array will be lost or "clipped."

Commercial Status

Since 2020, utility-scale solar has accounted for nearly 40% of all new generating capacity in the United States. More than 30 GWac was installed in 2024.[186] According to LBNL data, approximately 118 GW of solar PV capacity was operational in the United States at the end of 2024.[187] PV module efficiency has increased considerably over the past decade. The median inverter loading ratio ("ILR" is the ratio of DC to AC capacity) for tracking solar PV projects installed in 2024 was 1.33.[188] This

[186] Lawrence Berkeley National Laboratory. "Utility-Scale Solar, 2025 Data Update" available at: https://emp.lbl.gov/publications/us-utility-scale-solar-2025-data
[187] Lawrence Berkeley National Laboratory. "Utility-Scale Solar, 2025 Data Update" available at: https://emp.lbl.gov/publications/us-utility-scale-solar-2025-data

[188] Lawrence Berkeley National Laboratory. "Utility-Scale Solar, 2025 Data Update" available at:

value has been consistent over the prior six (6) years. Solar PV installations with tracking continue to be preferred to fixed-tilt configurations; of the approximately 30 GW of solar installed in 2024, less and 0.4 GW were fixed-tilt.[189]

Operational Characteristics

Three (3) Oregon locations are used to represent stand-alone solar PV resources in the IRP: one central Oregon (east of Cascades) location near Christmas Valley, one location with a similar longitude (east of Cascades) but farther north near Wasco, and one location with a similar latitude as Wasco but in the Willamette Valley (west of the Cascades) near McMinnville (Table 55). A solar PV resource near Mead, Nevada, which will be accessed via incremental transmission action is included in PGE's analysis as well.

Table 55. Summary of Stand-Alone Solar PV Operational Characteristics 2030 COD

Site	Lat.	Long.	IRP CF%
Central Oregon (Christmas Valley)	43.25	-120.62	28.3%
Oregon Gorge (Wasco)	45.61	-120.70	27.1%
Willamette Valley (McMinnville)	45.21	-123.18	22.5%
Nevada (Mead)	35.89	-114.98	33.6%

These proxy Solar PV resources utilize single-axis tracking. Energy estimates are created in SAM using crystalline silicon modules with 21% nominal efficiency and inverter efficiency of 97%; the ILR is 1.34.

Similar to the rationale for onshore wind, resource configurations remain constant across the four Solar PV sites. This focuses on solar resource variations rather than attempting to optimize each site's design. It is expected that developers in the marketplace will employ their expertise to design an optimal solar PV resource for any specific location. An hourly generation profile is simulated for each year of weather data for each site listed in Table 55. As described above, these hourly generation profiles are produced using SAM.

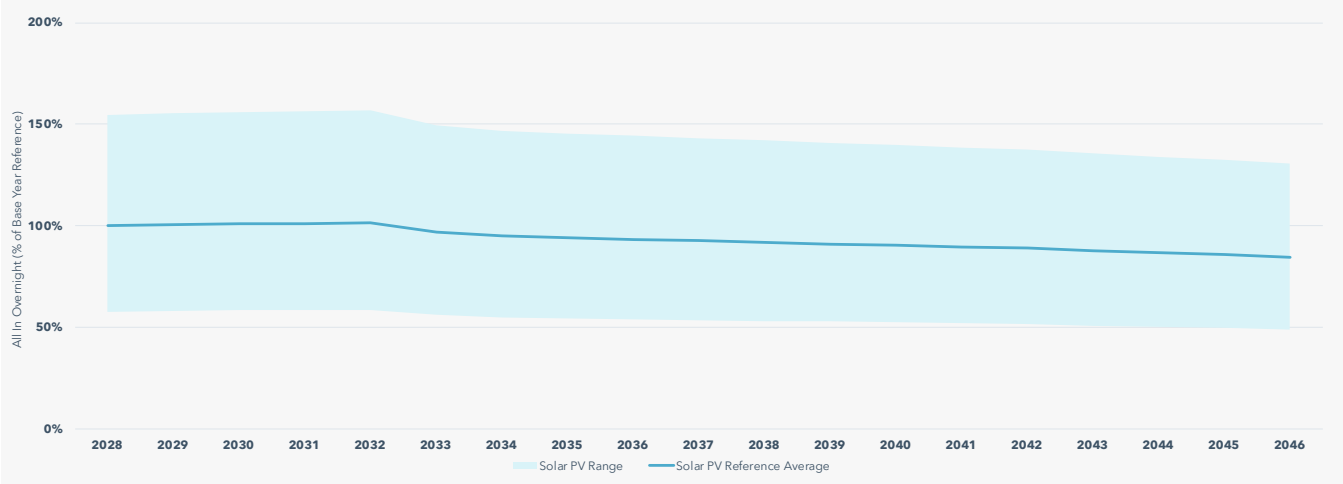
Forward Capital Cost Curve

The projection of future capital costs for solar PV resources is shown in Figure 120.

https://emp.lbl.gov/publications/us-utility-scale-solar-2025-data

[189] Lawrence Berkeley National Laboratory. "Utility-Scale Solar, 2025 Data Update" available at: https://emp.lbl.gov/publications/us-utility-scale-solar-2025-data

Figure 120. Solar PV Capital Cost Trajectory



G.5.3 Energy Storage Resources

G.5.3.1 Lithium-ion Battery Energy Storage

Technology Description

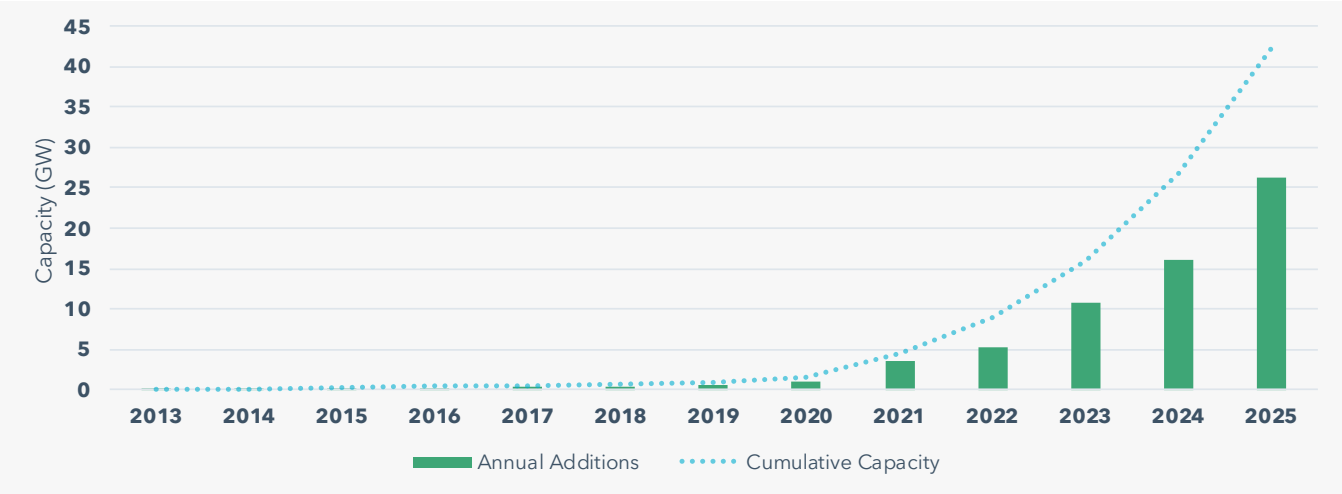
PGE's IRP uses lithium-ion technology for analysis of battery energy storage systems (BESS) in this IRP. The cost and performance of 4- and 6-hour storage durations are evaluated.

Commercial Status

According to EIA data, at the end of 2021, nearly 44 GW of battery energy storage capacity was operable in the United States. In 2023, 2024, and 2025, approximately 7, 11, and 16 GW came online, respectively.[190] The vast majority of these storage resources, about 42 GW or nearly 97% of the 44 GW total, are classified as lithium-ion batteries in the EIA data.

[190] 2025 Form EIA-860 Data Early Release - Schedule 3_4, Energy Storage' (Operable Units Only)

Figure 121. Lithium-ion Battery – Annual and Cumulative Operable Capacity (GW)



Operational Characteristics

The representative BESS costs and performance characteristics are based on lithium-ion technology. Data for a four-hour duration are sourced from 1898 & Co. based on a near-term COD.

Table 56. Long-duration Battery Energy Storage System Characteristics

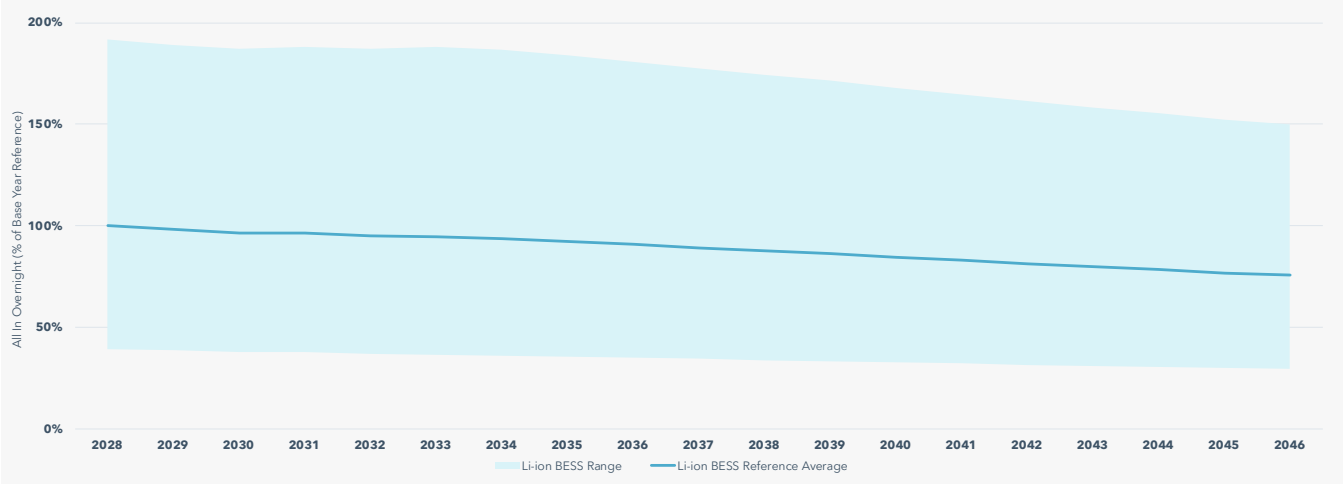
Chemistry	Duration (hours)	Round-trip Efficiency (%)	Annual Degradation (%)[191]
Lithium-ion	4	85%	1.5%
Lithium-ion	6	85%	1.5%

Forward Capital Cost Curve

The trajectory of future costs is informed by the long-term projections contained in the Wood Mackenzie LCOE report. The Reference Case scenario and range is presented in Figure 122.

[191] Cost of overbuild and augmentation to negate degradation is included for lithium-ion resources.

Figure 122. Lithium-ion Battery Energy Storage System Capital Cost Trajectory



G.5.3.2 Long-duration Battery Energy Storage System

Technology Description

PGE's IRP also includes a long-duration battery energy storage resource that is assumed to employ a generic non-lithium-ion technology. This resource can provide a stated 100 hours of energy storage. Per technology descriptions for EIA data reporting, these resources would likely be reported as "metal-air" batteries.

Commercial Status

No BESS in the 100 hour range were operating by year end 2025, according to EIA data. However, several projects are reportedly under development with online dates potentially in 2027.[192]

Operational Characteristics

The representative battery energy storage systems (BESS) costs and performance characteristics are sourced from 1898 & Co. Most notably, these long duration, metal-air chemistry batteries are characterized by relatively lower efficiencies (when compared to shorter duration lithium-ion). Additionally, there are no costs included to counteract the expected degradation in energy storage capacity. As a result, modeled energy storage capacity approximates the lifetime average assuming 2% annual degradation, as shown in Table 57 below.

Table 57. Long-duration Battery Energy Storage System Characteristics

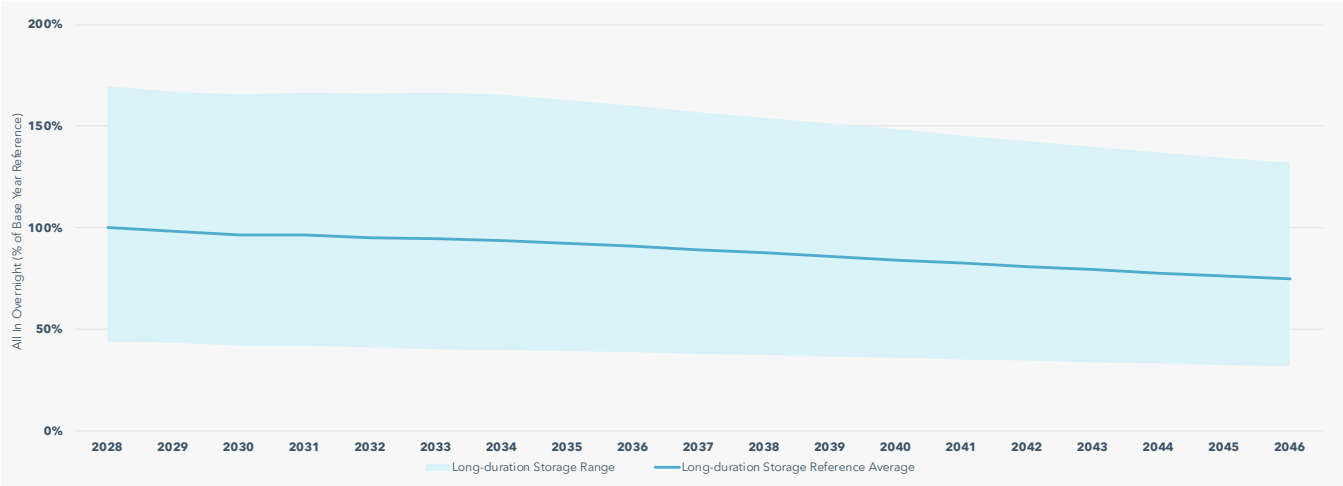
Chemistry	Duration (hours)	Round-trip Efficiency (%)	Annual Degradation (%)193
Metal-Air	100	33%	2%

[192] 2025 Form EIA-860 Data - Schedule 3_4, Energy Storage' (Proposed Units Only)
[193] Cost of overbuild and augmentation to negate degradation is not included for non-lithium-ion resources.

Forward Capital Cost Curves

For purposes of IRP analysis, the trajectory of capital costs for this long-duration storage technology is expected to approximately follow that of lithium-ion BESS. The Reference Case and range is presented in Figure 123.

Figure 123. Long-duration Battery Energy Storage System Capital Cost Trajectory



G.5.3.3 Pumped Hydroelectric Energy Storage

Technology Description

Pumped hydropower energy storage resources generally employ two reservoirs at different locations. Water is pumped to the higher-elevation reservoir and stored, which converts electrical energy to operate the pumps into potential energy (charging). When the water is released from the reservoir it flows through a turbine, generating electricity (discharging).

Commercial Status

According to EIA data, approximately 22 GW of pumped hydropower capacity was operable in the United States at the end of 2021. However, no new capacity has come online in nearly a decade, with only 330 MW of new capacity operable since 1995.[194] EIA does report that 2.6 GW of new pumped storage capacity is under development in the Form 860 reporting period; 600 MW is stated to potentially be online in 2027 and 2 GW in 2028.[195]

Operational Characteristics

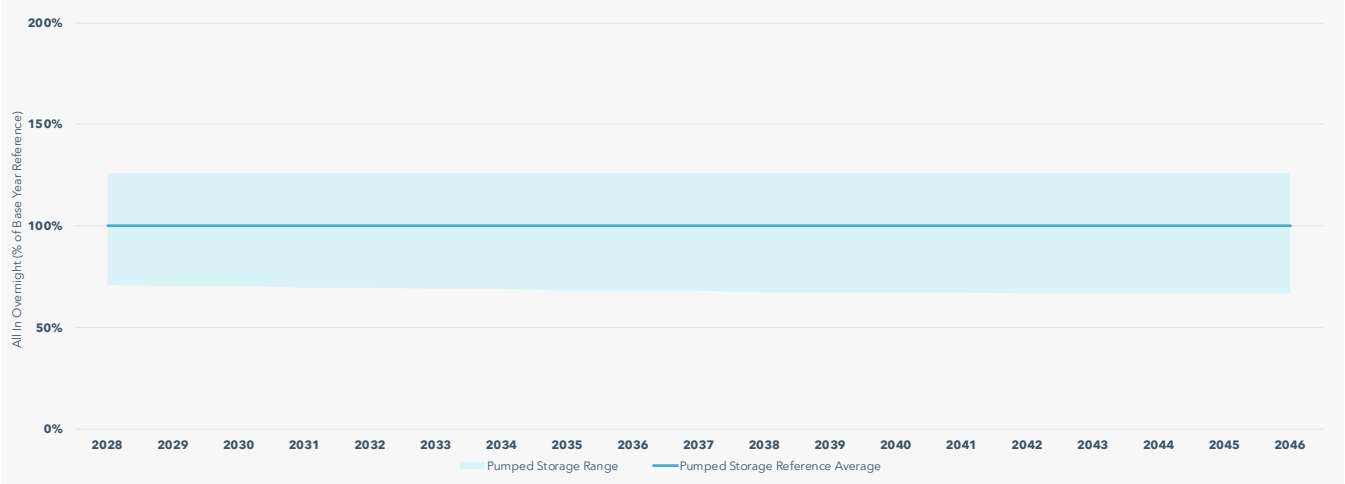
The pumped-storage hydropower resource is a 400 MW closed-loop system (water is pumped between two (2) reservoirs and is not connected to a water system) providing 10 hours of energy storage. The availability of this resource is geographically limited. Costs and performance attributes of this representative resource are based on an analysis performed by 1898 & Co.

[194] 2025 Form EIA-860 Data Early Release - Schedule 3, 'Generator Data' (Operable Units Only)
[195] 2025 Form EIA-860 Data Early Release - Schedule 3, 'Generator Data' (Operable Units Only)

Forward Capital Cost Curve

The projection of future capital costs is presented in Figure 124.

Figure 124. Pumped Hydropower Storage Capital Cost Trajectory



G.5.4 Co-located Resources

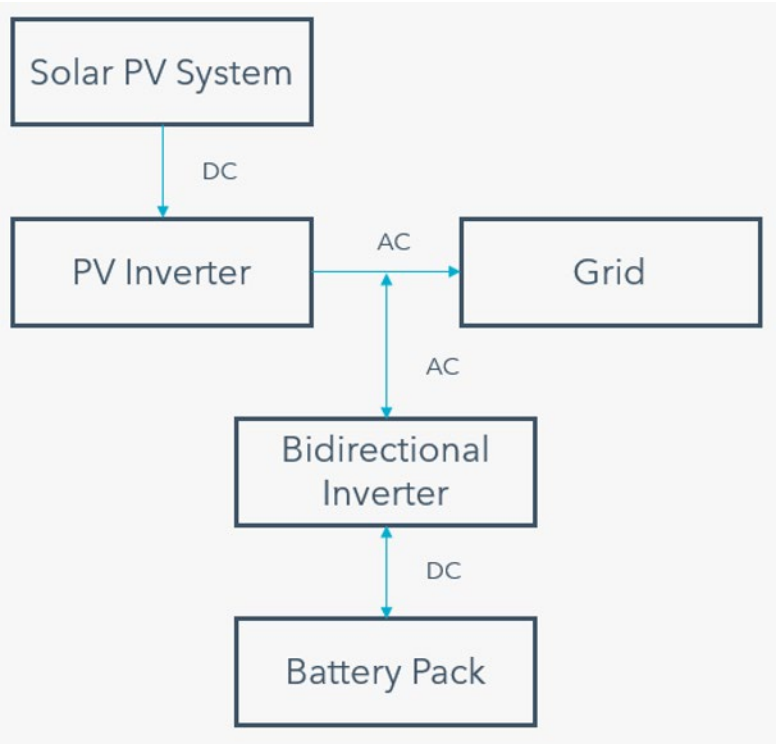
Co-located resources pair multiple resource types behind a single interconnection. These resource types could be different fuel sources, means of generation, or generating resources and energy storage resources. Hybrid resources are typically co-located resources combining one or more generating resources with an energy storage resource to operate in a coordinated manner. In this 2026 IRP, PGE models two (2) configurations of hybrid resources: 1) solar PV with battery energy storage ("solar + storage"), and 2) wind, solar PV, and battery energy storage resources ("wind + solar + storage").

G.5.4.1 Co-located Solar Photovoltaic + Battery Energy Storage

Technology Description

Multiple elements are required when describing a solar + storage resource, including resource coupling (AC- or DC-coupled), solar-to-storage ratio, solar-to-inverter ratio ("inverter loading ratio" as described previously), and storage duration. The solar and BESS components could be coupled on the AC side of the inverters (AC-coupled) or the DC side of the inverter (DC coupled). When AC-coupled, the battery and solar resources use separate inverters. IRP proxy resources are configured as AC-coupled. Figure 125 illustrates the basic elements of this configuration.

Figure 125. Illustrative AC-coupled Solar + Storage



Commercial Status

Solar + storage were the dominant form of hybrid resources by the end of 2024—accounting for more than 60% when measured on a generation capacity basis. Solar and storage hybrids also saw a significant installed capacity increase; nearly 60% of all hybrid solar + storage resources came online in 2024 (also on a generation capacity basis).[196]

Operational Characteristics

Given the large number of hybrid resource permutations that would arise from investigating sensitivities around each design element, the IRP simplifies the analysis to include a representative solar and BESS hybrid resource configuration at two locations as shown in Table 58. At each location, these two (2) hybrid resources:

- Employ an AC-coupled configuration.
- Feature a storage power capacity equivalent to the solar inverter rating (1:1).
- Utilize the Christmas Valley and McMinnville solar locations discussed previously, including the 1.34 ILR.
- Include BESS with four-hour storage duration and no ability to grid charge.

[196] Lawrence Berkeley National Laboratory. "Land-based Wind Energy Technology Data Update: 2025 Edition," available at: https://eta-publications.lbl.gov/sites/default/files/2025-08/data_file_land-based_wind_energy_technology_update_2025_edition.xlsx

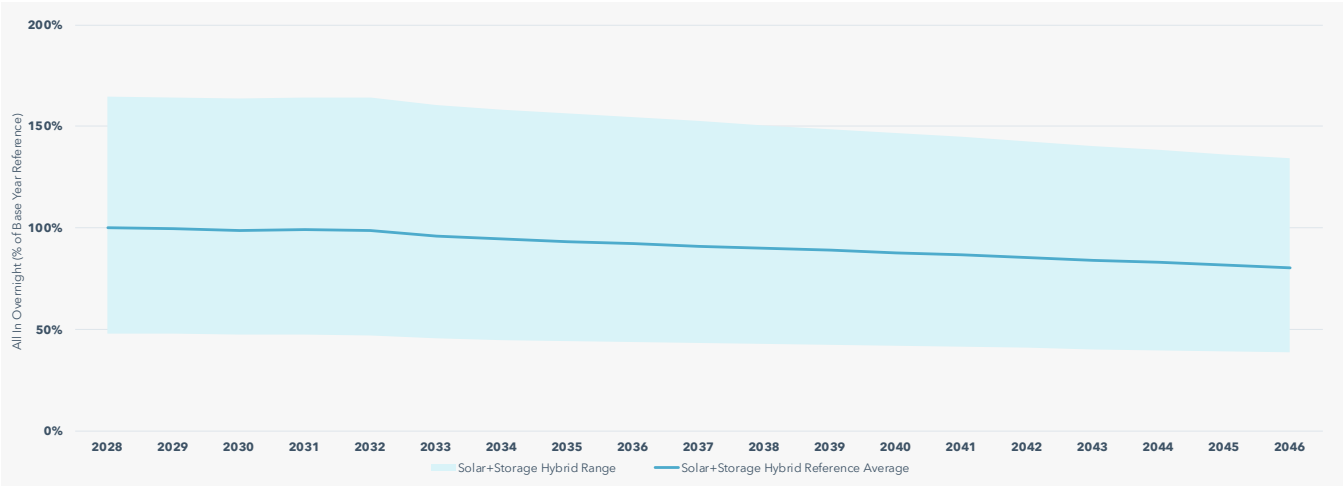
Table 58. Hybrid PV + BESS

Description	Central Oregon Solar + 4-Hour BESS	Willamette Valley Solar + 4-Hour BESS
Location (Lat., Long.)	43.25, -120.62	43.25, -120.62
Capacity (MWac)	100	100
Duration (hours)	4	4
Round-Trip Efficiency	85%	85%
Solar Capacity Factor	28.6%	23.0%
Solar ILR	1.34	1.34
Solar Capacity (MWdc)	134	134
Storage Ratio	1:1	1:1
Storage Capacity (MW)	100	100

Forward Capital Cost Curve

The hybrid capital costs are a function of the solar PV and BESS components. As such, the trajectory of future capital costs depends on the developments assumed for those components. The Reference Case and range of scenarios are presented in Figure 126:

Figure 126. Hybrid Solar + Storage Capital Cost Trajectory



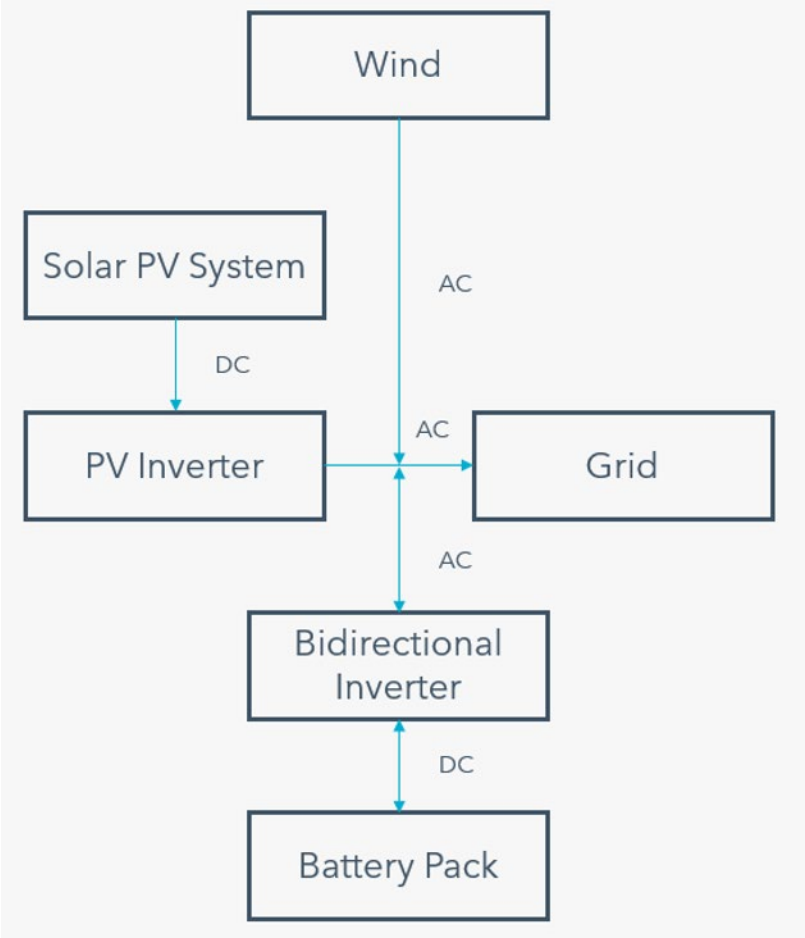
G.5.4.2 Co-located Wind + Solar Photovoltaic + Battery Energy Storage

Technology Description

PGE's wind, solar PV, and battery energy storage hybrid resources ("wind + solar + storage") combines solar PV and wind generation with battery energy storage in an AC-coupled configuration. The solar and storage components of these proxy resources are consistent with solar + storage described above (solar-to-storage ratio, inverter loading ratio and storage duration). The wind portion of this hybrid is added at a ratio of 1.5:1.0 relative to the solar + storage capacity. The

interconnection is equivalent to the wind capacity. Figure 127 illustrates the basic elements of the wind + solar + storage resource.

Figure 127. Illustrative AC-coupled Wind + Solar + Storage



Commercial Status

According to data compiled by Lawrence Berkeley National Laboratory, relatively few wind + solar + storage hybrid projects were online in the US by the end of 2024; with only five projects operating. However, at the end of 2024, 37 wind + solar + storage projects were present in interconnection queue requests (approximately 38% of wind hybrid requests).[197]

Operational Characteristics

Similar to solar + storage above, the IRP simplifies the analysis of wind + solar + storage to include a single hybrid resource at each of the five standalone wind locations as shown in Table 59. At each location these hybrid resources:

- Employ an AC-coupled configuration.

[197] Lawrence Berkeley National Laboratory. "Land-based Wind Energy Technology Data Update: 2025 Edition," available at: https://eta-publications.lbl.gov/sites/default/files/2025-08/data_file_land-based_wind_energy_technology_update_2025_edition.xlsx

- Feature a storage power capacity equivalent to the solar inverter rating (1:1) and a wind to solar + storage ratio of 1.5:1.0.
- Utilize each of the wind locations discussed previously, with corresponding solar generation profiles estimated using an ILR of 1.34.
- Include BESS with four-hour storage duration and no ability to grid charge.
- Are subject to an interconnection equal to the wind generator capacity.

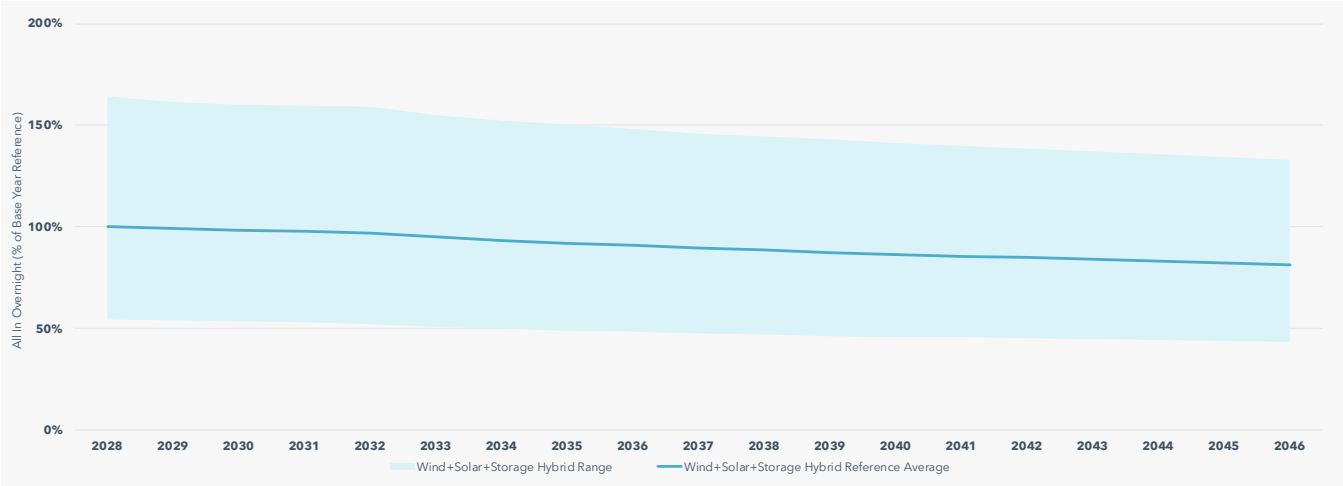
Table 59. Summary of Hybrid Solar PV + BESS Operational Characteristics

Description	Oregon Gorge Wind + Solar + 4 Hour BESS	SE Washington Wind + Solar + 4 Hour BESS	Montana Wind + Solar + 4 Hour BESS	North Dakota Wind + Solar + 4 Hour BESS	Wyoming Wind + Solar + 4 Hour BESS
Location (Lat., Long.)	45.65, -120.63	46.41, -117.84	46.81, -106.22	47.71, -101.33	43.04, -105.56
Interconnection (MWac)	150	150	150	150	150
Wind Capacity Factor	37.1%	38.9%	40.7%	42.4%	42.4%
Wind Capacity (MWac)	150	150	150	150	150
Solar Capacity Factor	27.3%	24.9%	25.6%	25.3%	28.1%
Solar ILR	1.34	1.34	1.34	1.34	1.34
Solar Capacity (MWdc)	134	134	134	134	134
Storage Ratio	1:1	1:1	1:1	1:1	1:1
Storage Capacity (MW)	100	100	100	100	100
Duration (hours)	4	4	4	4	4
Round-Trip Efficiency	85%	85%	85%	85%	85%

Forward Capital Cost Curve

The hybrid capital costs are a function of the wind, solar PV, and BESS components. The Reference Case and range of scenarios is presented in Figure 128.

Figure 128. Hybrid Wind + Solar + Storage Capital Cost Trajectory



G.5.5 Dispatchable Resources

G.5.5.1 Nuclear

Technology Description

The nuclear-fueled generating option is a representative small modular reactor (SMR). The International Atomic Energy Agency sets criteria for the classification of an SMR:[198]

- Small – physically a fraction of the size of a conventional nuclear power reactor.
- Modular – making it possible for systems and components to be factory-assembled and transported as a unit to a location for installation.
- Reactors – harnessing nuclear fission to generate heat to produce energy.

Potential benefits of SMRs relative to large-scale nuclear power plants include: physical size that eases siting constraints, fabrication practices ease manufacturing complexities and shorten construction timelines, designs can increase safety margins.[199]

The SMR resource is based on a representative design of 300 MW capacity boiling water reactor.

Commercial Status

At the end of 2025, nearly 104 GW of nuclear capacity was operable in the United States, according to EIA data. Voglte Unit 3 and Unit 4 came online in 2023 and 2024, respectively; each represents more than 1 GW or generating capacity.[200] Nearly 5 GW are currently proposed to come online

[198] https://www.iaea.org/newscenter/news/what-are-small-modular-reactors-smrs
[199] https://www.iaea.org/newscenter/news/what-are-small-modular-reactors-smrs
[200] 2025 Form EIA-860 Data Early Release - Schedule 3, 'Generator Data' (Operable Units Only)

between 2030 and year-end 2032—although these amounts may not reflect the potential restart of previously retired nuclear facilities.[201]

Operational Characteristics

In resource dispatch modeling, the SMR resource operation is subject to economic dispatch between minimum and maximum capacity.

Table 60. Summary of Nuclear-powered Generating Resource Operational Characteristics

Operational Characteristics	Nuclear SMR
Capacity (MW average lifetime)	300
Planned outage rate	5.0%
Forced outage rate	5.0%

G.5.5.2 Geothermal

Technology Description

Geothermal energy is the heat contained in the Earth's interior. This heat is typically accessed for electricity generation by the drilling of injection and production wells. Heat recovery generally generates electricity from geothermal resources in the form of hot water or steam via a well drilled into the earth. The hot water or steam produced turns a turbine and generator. Resources are broadly categorized as hydrothermal, enhanced geothermal systems (EGS), advanced or closed-loop geothermal, and superhot rock or supercritical.[202] Hydrothermal resources are those where the naturally occurring rock structure and groundwater flow are sufficient to support energy recovery. EGS resources have sufficient heat but require engineering techniques to introduce liquid or allow liquid flow within the rock structure. Advanced, or closed-loop, systems use a closed system of pipes to heat the circulating fluids. The superhot or supercritical technologies utilize very high temperatures and pressures (where the liquid reaches a "supercritical" state) to produce a high-energy working liquid.

Commercial Status

Nationally, according to EIA data, approximately 4 GW of geothermal generating capacity was operable at the end of 2025.[203] An additional 190 MW is proposed to be operating by 2028. Two (2) projects are operating in Oregon, representing approximately 37 MW.

The geothermal projects currently operating in Oregon are the Neal Hot Springs plant, near Vale in eastern Oregon, and Paisley Geothermal, near the town of Paisley in south central Oregon.

The Newberry EGS Demonstration project in central Oregon is exploring EGS development with the potential for a future 35 MW binary power plant.[204]

[201] 2025 Form EIA-860 Data Early Release - Schedule 3, 'Generator Data' (Operable Units Only)
[202] https://www.energy.gov/hgeo/geothermal/geothermal-electricity-generation
[203] 2025 Form EIA-860 Data Early Release - Schedule 3, 'Generator Data' (Operable Units Only)
[204] https://altarockenergy.com/projects/newberry-egs-demonstration/

Operational Characteristics

The representative geothermal plant in the IRP uses resource cost characteristics consistent with an EGS resource sited in the state of Oregon.

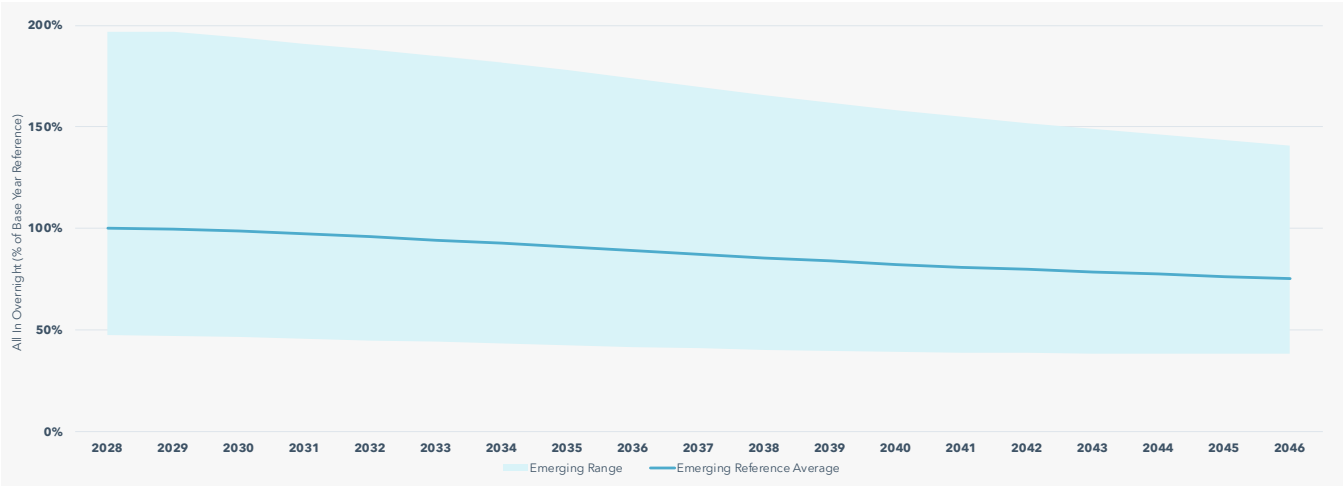
Table 61. Summary of Enhanced Geothermal Resource Operational Characteristics

Operational Characteristics	Enhanced Geothermal
Capacity (MW average lifetime)	50
Planned outage rate	4.8%
Forced outage rate	3.0%

Forward Capital Cost Curve

The projection of future capital costs for the emerging dispatchable resources such as nuclear SMR and enhanced geothermal are presented in Figure 129.

Figure 129. Emerging Dispatchable Capital Cost Trajectory



G.5.6 Natural Gas-fueled Resources

G.5.6.1 Simple- and Combined-cycle Combustion Turbines

Technology Description

The simple-cycle combustion turbine (SCCT) is based on an F-class CT in simple-cycle configuration with approximately 230 MW net output. The combined-cycle combustion turbine (CCCT) resource comprises one H-class combustion turbine (CT), one steam turbine generator (STG), and one electric generator that is common to the CT and the STG.

Commercial Status

Natural gas-fired resources represent the largest share of generating capacity in the United States; approximately 42% as of year-end 2025. Simple- and combined-cycle combustion turbine

generator capacity operating in the US as of year-end 2025 totaled nearly 500 GW.[205] An additional 65 GW is proposed to come online by year-end 2030.[206]

Operational Characteristics

The proxy IRP natural gas-fired resources are included in PGE's dispatch modeling with the general characteristics summarized in Table 62 below. These resources are assumed to be fueled with natural gas priced at AECO (Alberta).

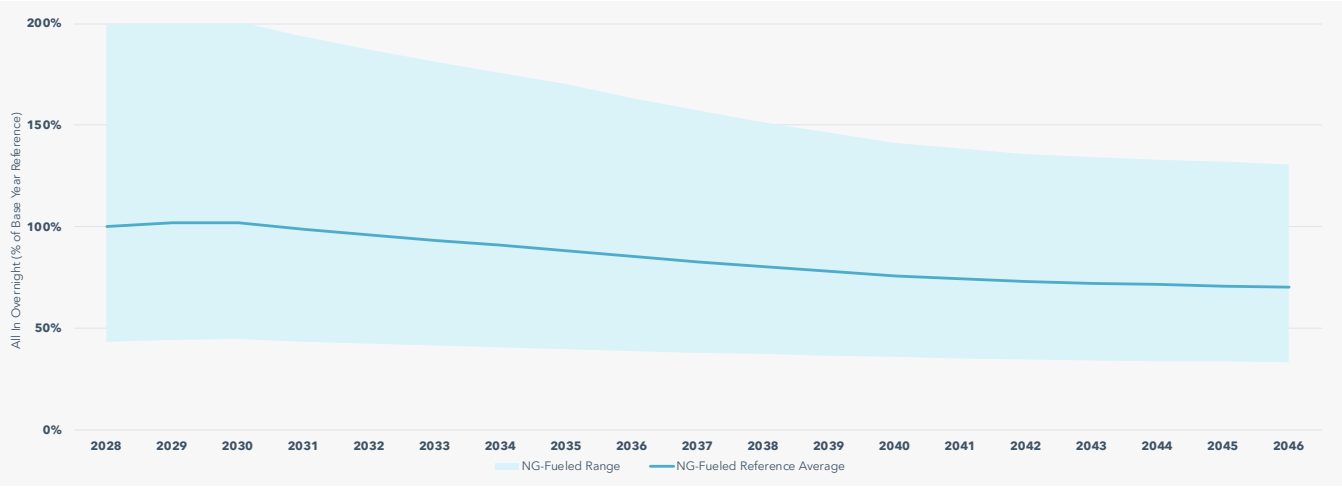
Table 62. Summary of Proxy CCCT and SCCT Operational Characteristics

Operational Characteristics	CCCT H-Class	SCCT F-Class
Capacity (MW average lifetime)	700	230
Heat Rate (Btu/kWh average lifetime)	6,200	9,890
Planned outage rate	3.9%	2.4%
Forced outage rate	2.2%	1.7%

Forward Capital Cost Curve

The future capital cost trajectory and range for natural gas-fueled SCCT and CCCT resources are presented in Figure 130.

Figure 130. Simple- and Combined-cycle Combustion Turbine Capital Cost Trajectory



[205] 2025 Form EIA-860 Data Early Release - Schedule 3, 'Generator Data' (Operable Units Only)
[206] 2025 Form EIA-860 Data Early Release - Schedule 3, 'Generator Data' (Operable Units Only)

G.6 Resource Accreditation

G.6.1 Overview

Accreditation for supply-side resources is the evaluation of each technology's capacity contribution, or effective load carrying capability (ELCC). ELCC is a measure of the marginal contribution of a resource toward system reliability and is an extension of loss-of-load probability (LOLP) modeling using Sequoia (Appendix Section H.5). The ELCC of each resource is determined through an "with-and-without" exercise where incremental quantities added to the base system change the perfect capacity required to achieve the 1-day-in-10-years reliability metric. The change in perfect capacity (MW) over the nameplate (MW) added represents the ELCC (%). The "with-and-without" exercise takes the following steps:

1. The model runs once to establish a baseline system capacity need
2. The model runs again with a new resource added
3. The difference in capacity need from the base system to the system with the resource added determines how much effective capacity the resource contributes
4. The amount of effective capacity the resource contributes is divided into its nameplate to determine the ELCC value

ELCCs for the 2026 CEP/IRP are estimated for summer and winter in the year 2032 with a capacity deficit of 1197 MW in summer and 960 MW in winter. Incremental resource additions in quantities between 100 MW to 2000 MW result in ELCC curves that capture the diminishing marginal returns of a resource's ability to reduce unserved energy and resolve the capacity need of the system. Figure 131 and Figure 132 display seasonal ELCC curves for four select resources.

Figure 131. Select Resource ELCC Curves - Summer

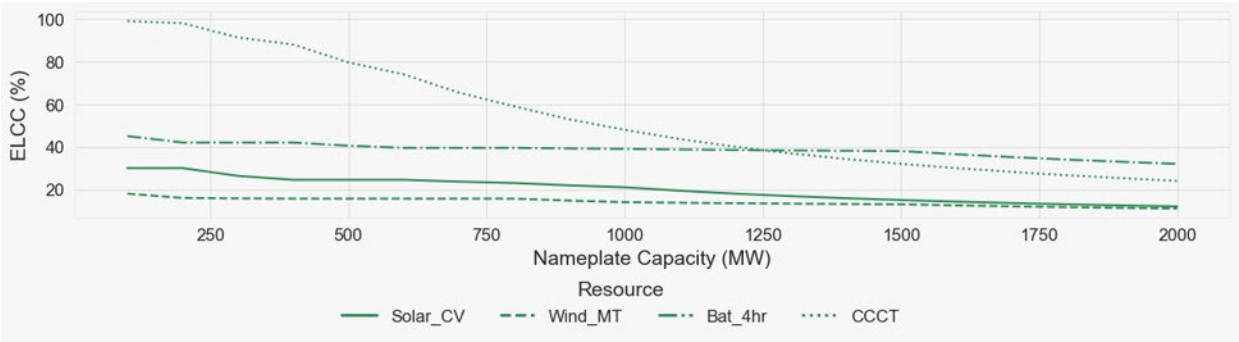
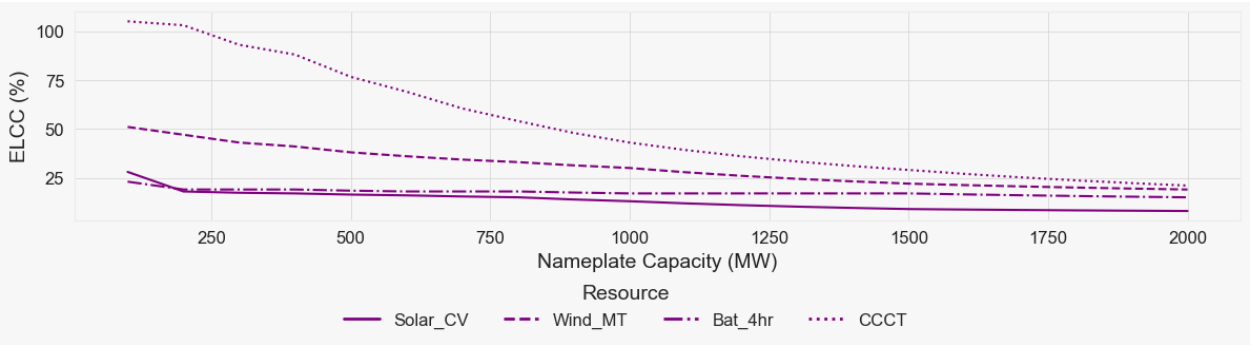


Figure 132. Select Resource ELCC Curves - Winter



The first 100 MW increment of a combined cycle combustion turbine (CCCT) provides approximately 100 MW of capacity reduction in both summer and winter, a 100% ELCC. The ELCC of CCCT then declines as the system's capacity deficit is resolved. Comparatively, 100 MW of four-hour lithium-ion battery (Bat_4hr) provides approximately 45 MW of capacity in summer and 23 MW in winter, a 45% and 23% ELCC, respectively. The ELCC of a four-hour battery resource declines much slower than the CCCT as incremental additions are less effective at solving system deficits. The relative comparison of resource ELCCs gives insight into each technology's ability to provide both energy and capacity during hours of greatest need (see Section 6.6.1.2) under increasing technology saturation.

As LOLP modeling in Sequoia captures both energy and capacity constraints in the system, it is recognized that complementary and antagonistic interactive effects exist as resources are added.[207] ELCC curves measure the marginal capacity contribution of a technology and do not capture such interactive effects when resources are elected in PGE's portfolio expansion model ROSE-E. For example, solar and short-duration storage resources are well-suited to complement one another during summer events, and the addition of 100 MW of solar is conceivably more valuable if 100 MW of storage is also added to the system. Conversely, positive correlation in wind profiles may act antagonistically, leading to a result where an additional quantity of Montana wind may provide less capacity if a large quantity of North Dakota wind is also added to the system. To validate resource interactive effects do not result in an overly adequate or deficit system, portfolios elected in ROSE-E are incorporated into Sequoia to test their adequacy in a modeling environment that respects energy and capacity interactions at an hourly granularity (see Section 7.11).

G.6.2 Resource Assumptions

Each technology's ability to resolve loss of load events reflects multiple resource specific assumptions including generation, roundtrip-efficiency, and transmission. Hourly generation profiles for VER resources are estimated using the National Laboratory of the Rockies (NRL) System Advisor Model (SAM). Figure 133 and Figure 134 display hourly median generation profiles for variable energy resources (VERs). The correlation of each generation shape with hours of greatest

[207] Resource Adequacy for the Energy Transition: A Critical Periods Reliability Framework and its Applications in Planning and Markets. Energy and Environmental Economics. 2025.

unserved energy is the primary determinant of the ELCC for candidate VER resources. Table XX displays round-trip efficiency estimates for storage resources. Lastly, it is assumed that off-system supply-side resources acquire firm transmission equal to 75% of the nameplate capacity. This change reflects an attempt to align transmission modeling assumptions with state resource adequacy requirements (e.g. WRAP) and future modeling.[208]

Figure 133. Solar Resource Generation Shapes

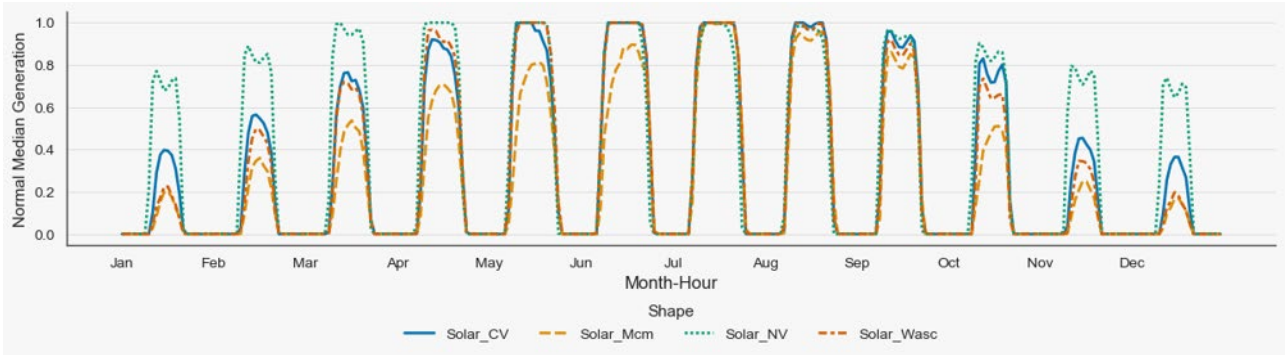


Figure 134. Wind Resource Generation Shapes

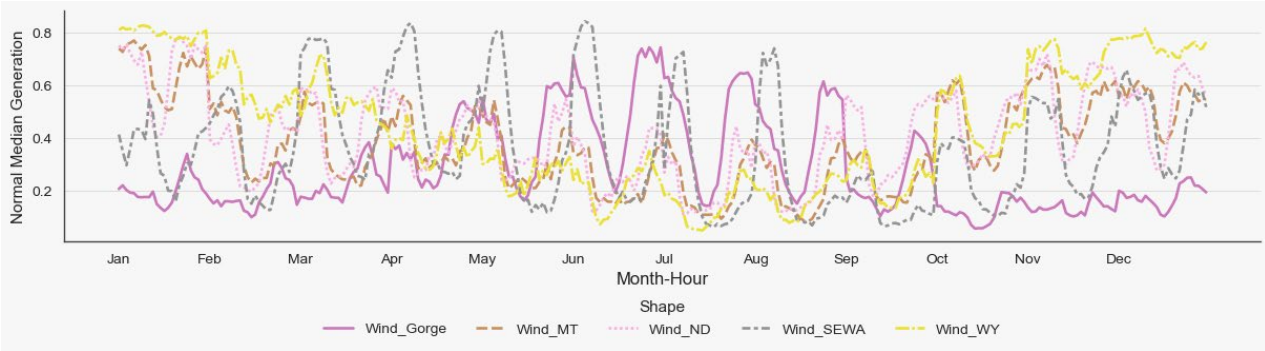


Table 63. Resource and Efficiency

Resource	Round-trip Efficiency
Lithium-ion Battery (various durations)	85%
Pumped-Storage Hydro	74%
Long-duration Storage (Iron-Air) Battery	35%

G.6.3 Resource ELCCs - Untuned

Table 64 and the figures that follow show seasonal ELCC curves used in portfolio expansion. These ELCCs are derived from testing marginal resource additions in a capacity inadequate system.[209]

[208] See LC 80 - Attachment 2. Staff Expectations for Future IRP–Transmission Modeling, and UM 2274 SMM Condition 5.
[209] PGE also tests ELCCs for select resources in a near-capacity adequate system described the section below.

Values are grouped by resource categories. Most resources are estimated at 100, 200, 400, 600, 800, 1000, 1500, and 2000 MW increments in Sequoia (Pattern 1). A monotonically decreasing curve is then fit across these estimates and values are interpolated to derive 20 tranches of resource additions. These curves are linearized to derive point and slope estimates for use in portfolio expansion. Certain resources have incremental addition caps in portfolio expansion, such as energy efficiency, flex load and distributed system generation resources. For such resources ELCC curves are flat beyond the resource specific cap (Pattern 2). Additionally, the Emerging resource is assumed to have an ELCC curve equivalent to CCCT. Table 64 lists the resources with ELCCs estimated in Sequoia.

Table 64. Resource Options

Resource Group	Resource Name	Resource Abbreviation	Estimation Pattern
Dispatchable	Emerging Dispatchable Clean Technology	Emerging	Pattern 1
Dispatchable	Combined-cycle Combustion Turbine	CCCT	Pattern 1
Dispatchable	Single-cycle Combustion Turbine	SCCT	Pattern 1
EE	Non-Cost-Effective Energy Efficiency – Bin 1	EE_1	Pattern 2
EE	Non-Cost-Effective Energy Efficiency – Bin 2	EE_2	Pattern 2
EE	Non-Cost-Effective Energy Efficiency – Bin 3	EE_3	Pattern 2
EE	Non-Cost-Effective Energy Efficiency – Bin 4	EE_4	Pattern 2
EE	Non-Cost-Effective Energy Efficiency – Bin 5	EE_5	Pattern 2
Flex Load	Demand Response - Bin 1	DR_1	Pattern 2
Flex Load	Demand Response - Bin 2	DR_2	Pattern 2
Flex Load	Demand Response - Bin 3	DR_3	Pattern 2
Flex Load	Demand Response - Bin 4	DR_4	Pattern 2
Flex Load	Demand Response - Bin 5	DR_5	Pattern 2
Other	Community-based renewable energy	CBRE	Pattern 2
Other	Distributed System Generation	DSG	Pattern 2
Other	Optimization of Existing Wind Generation	Wind_Opt	Pattern 2
Other	Repower of Existing Wind Generation	Wind_Repower	Pattern 2
Other	Small-Scale Renewable	SSR	Pattern 2
Solar	Christmas Valley Solar	Solar_CV	Pattern 1
Solar	McMinnville Solar	Solar_Mcm	Pattern 1
Solar	Nevada Solar	Solar_NV	Pattern 1
Solar	Wasco County Solar	Solar_Wasc	Pattern 1
Solar Hybrid	Christmas Valley - Solar: Storage (1:1)	CV_Hyb_1	Pattern 1
Solar Hybrid	McMinnville - Solar: Storage (1:1)	MCMN_Hyb_1	Pattern 1
Storage	Long-Duration Storage (100-hour Iron Air)	Bat_100hr	Pattern 1

Resource Group	Resource Name	Resource Abbreviation	Estimation Pattern
Storage	Lithium Ion Battery (4-hour)	Bat_4hr	Pattern 1
Storage	Lithium Ion Battery (6-hour)	Bat_6hr	Pattern 1
Storage	Pumped Storage Hydro (10-hours)	PSH_10hr	Pattern 1
Wind	Gorge Wind	Wind_Gorge	Pattern 1
Wind	Montana Wind	Wind_MT	Pattern 1
Wind	North Dakota Wind	Wind_ND	Pattern 1
Wind	Off-Shore Wind	Wind_Off	Pattern 1
Wind	Southeast Washington Wind	Wind_SEWA	Pattern 1
Wind	Wyoming Wind	Wind_WY	Pattern 1
Wind Hybrid	Gorge Hybrid - Wind: Solar: Storage (1:0.67:0.67)	Gorge_Hyb	Pattern 1
Wind Hybrid	Montana Hybrid - Wind: Solar: Storage (1:0.67:0.67)	MT_Hyb	Pattern 1
Wind Hybrid	North Dakota Hybrid - Wind: Solar: Storage (1:0.67:0.67)	ND_Hyb	Pattern 1
Wind Hybrid	Southeast Washington Hybrid - Wind: Solar: Storage (1:0.67:0.67)	SEWA_Hyb	Pattern 1

Figure 135. Solar – Summer

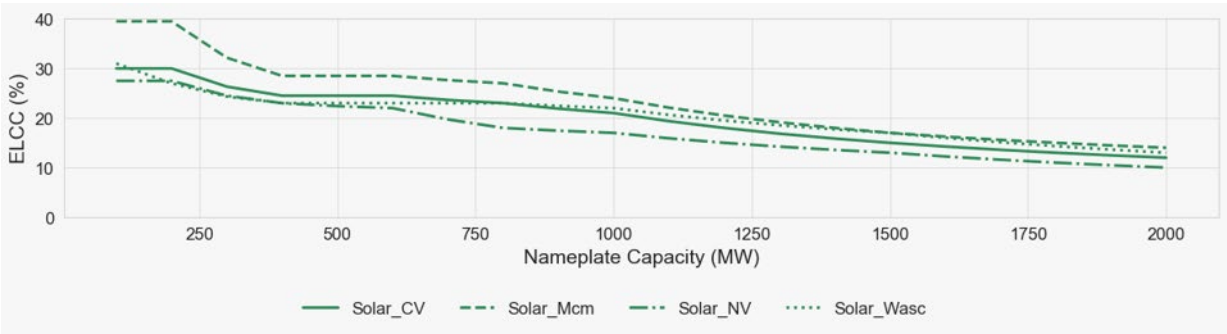


Figure 136. Solar – Winter

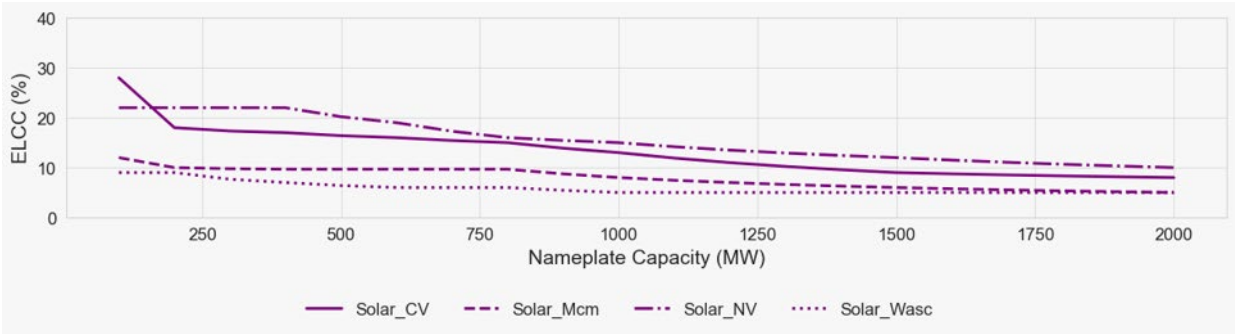


Figure 137. Wind - Summer

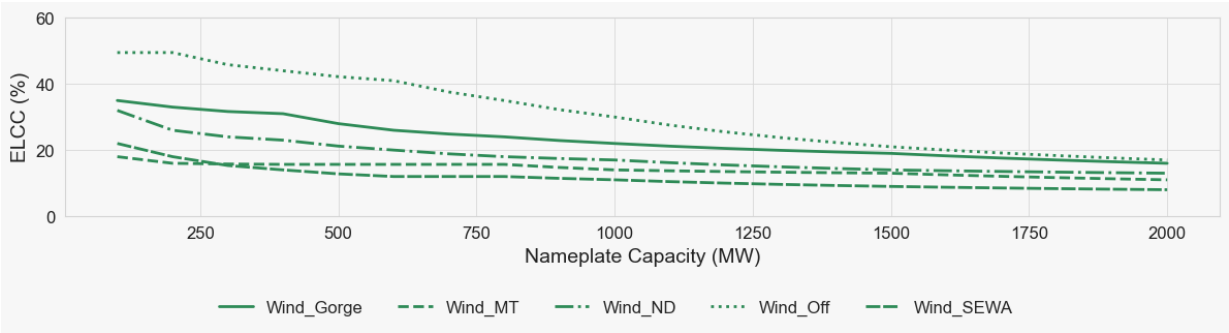


Figure 138. Wind - Winter

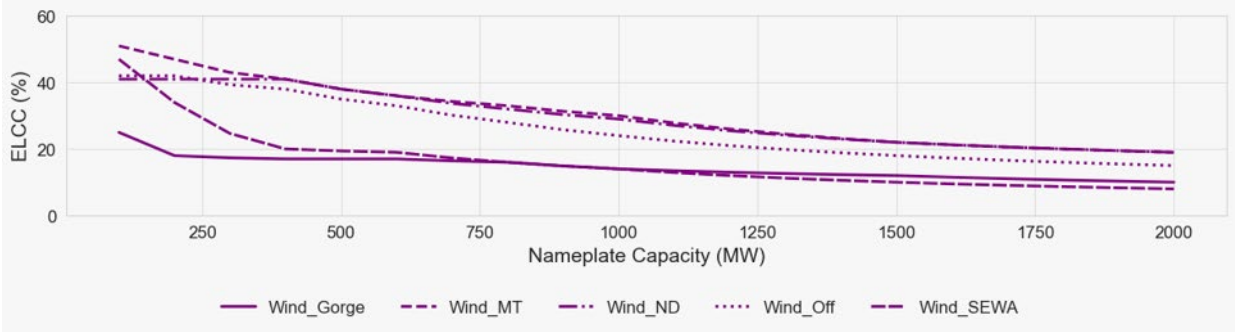


Figure 139. Storage - Summer

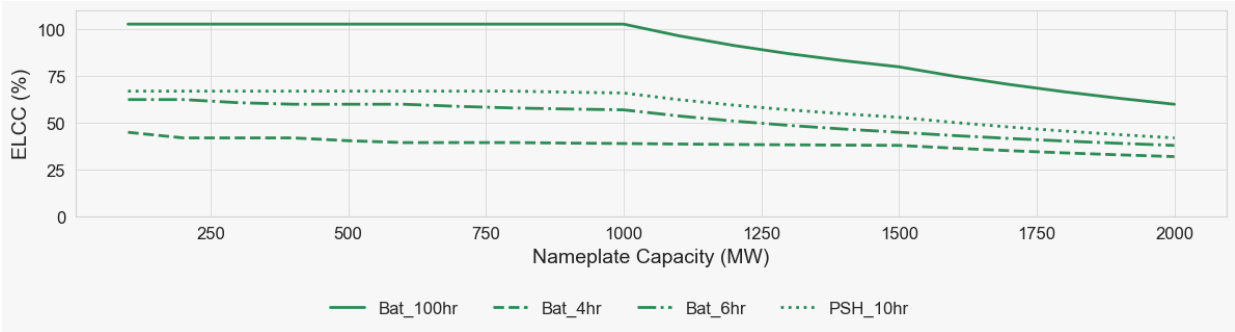


Figure 140. Storage - Winter

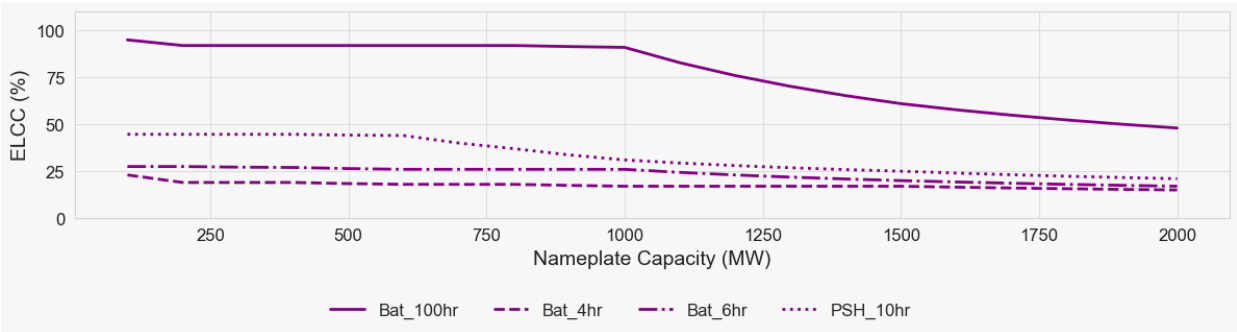


Figure 141. Dispatchable - Summer

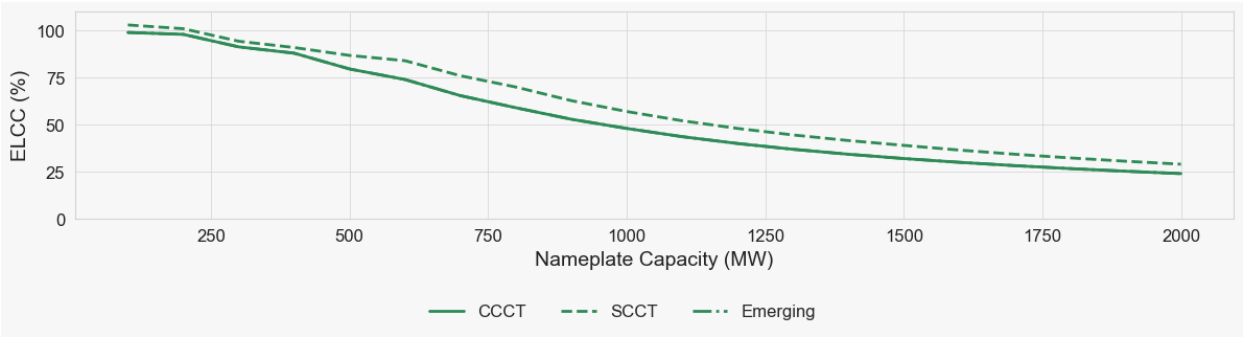


Figure 142. Dispatchable - Winter

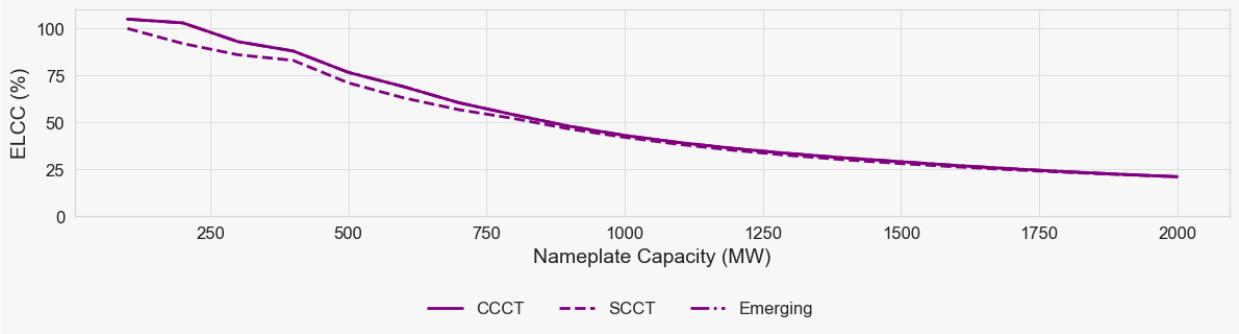


Figure 143. Solar Hybrid - Summer

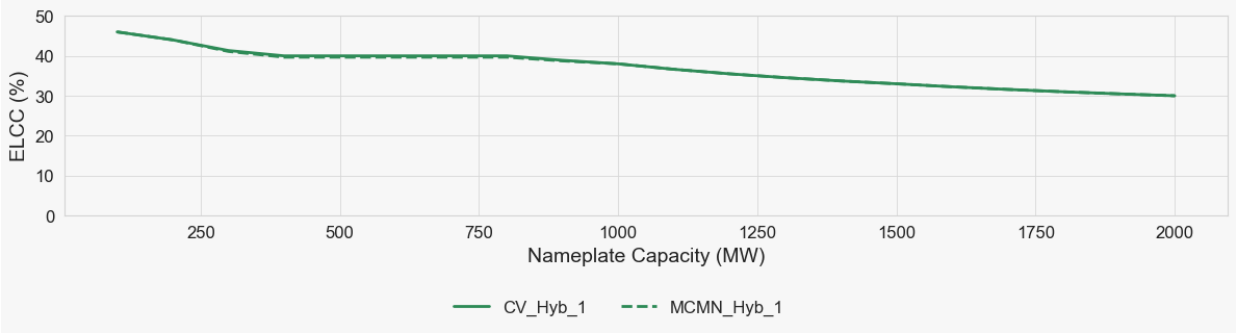


Figure 144. Solar Hybrid - Winter

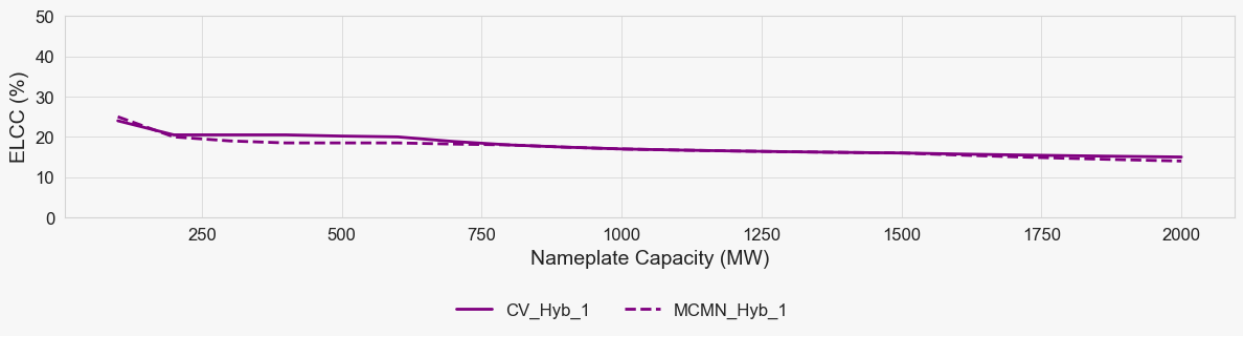


Figure 145. Wind Hybrid - Summer

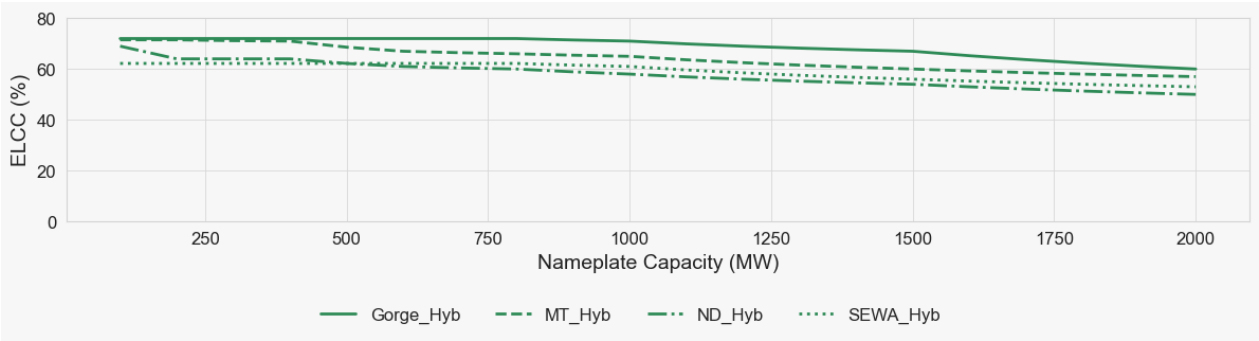


Figure 146. Wind Hybrid - Winter

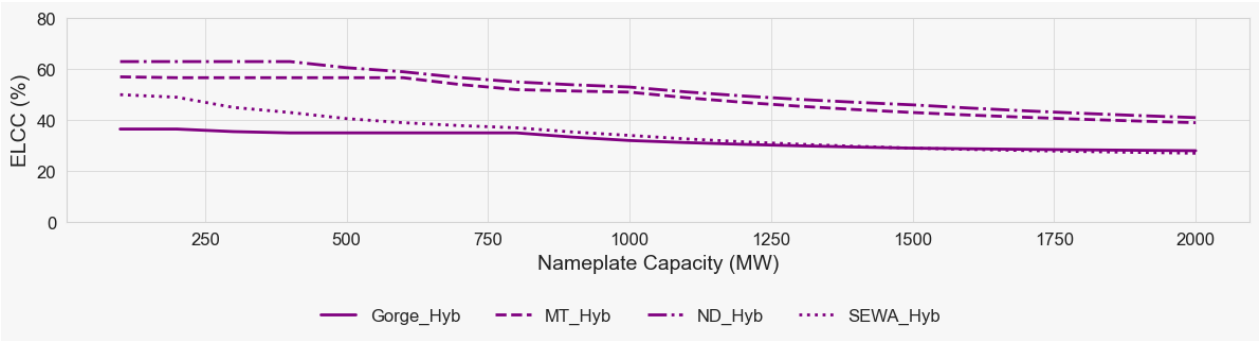


Figure 147. Other - Summer

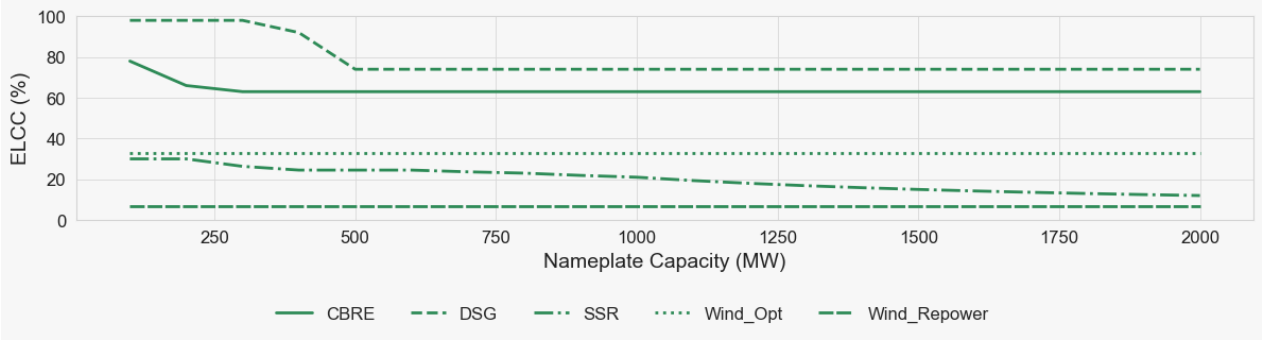


Figure 148. Other - Winter

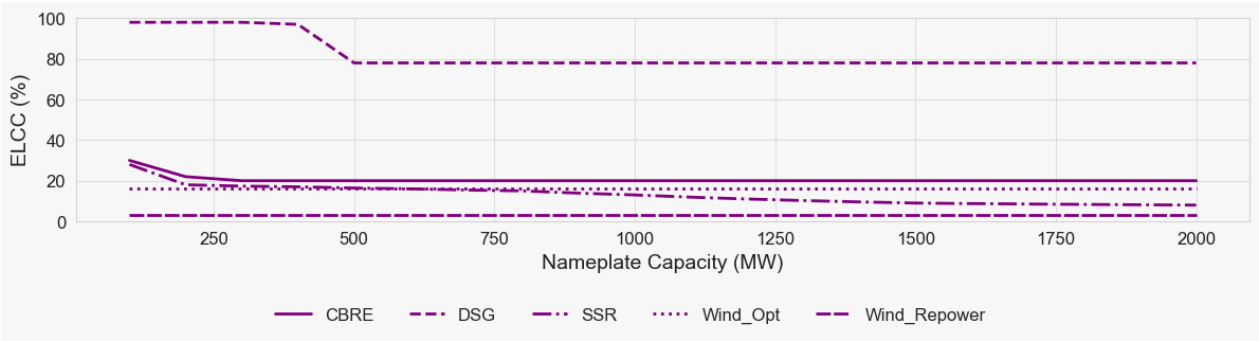


Figure 149. Flex Load - Summer

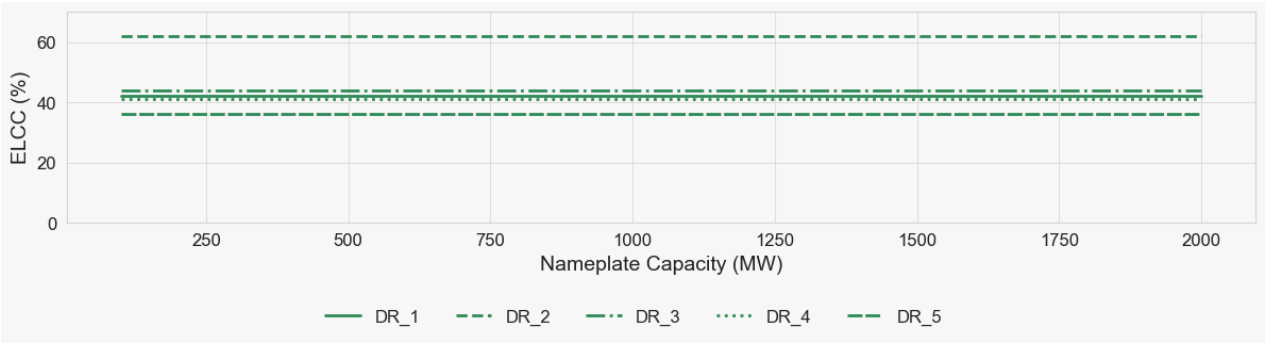


Figure 150. Flex Load - Winter

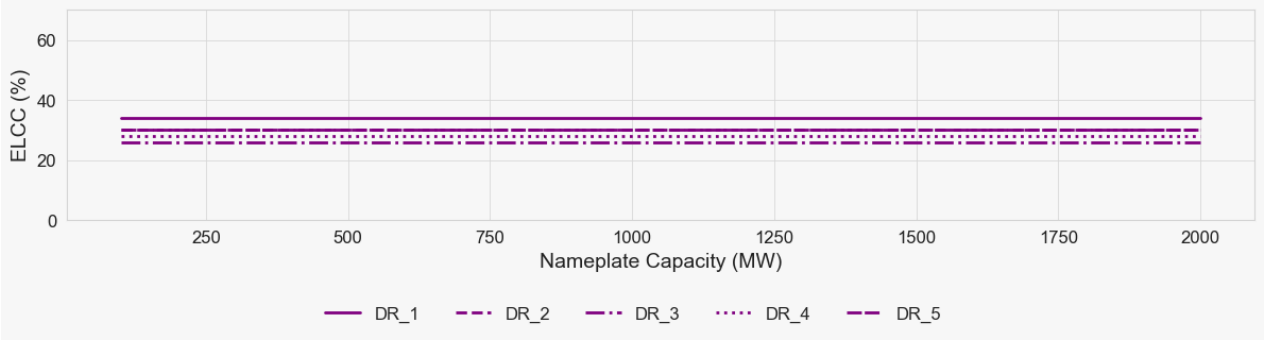


Figure 151. Energy Efficiency - Summer

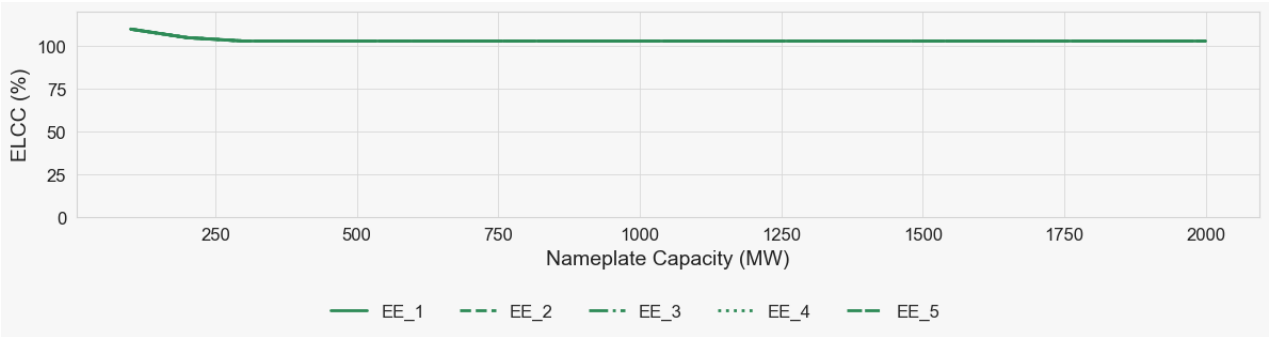
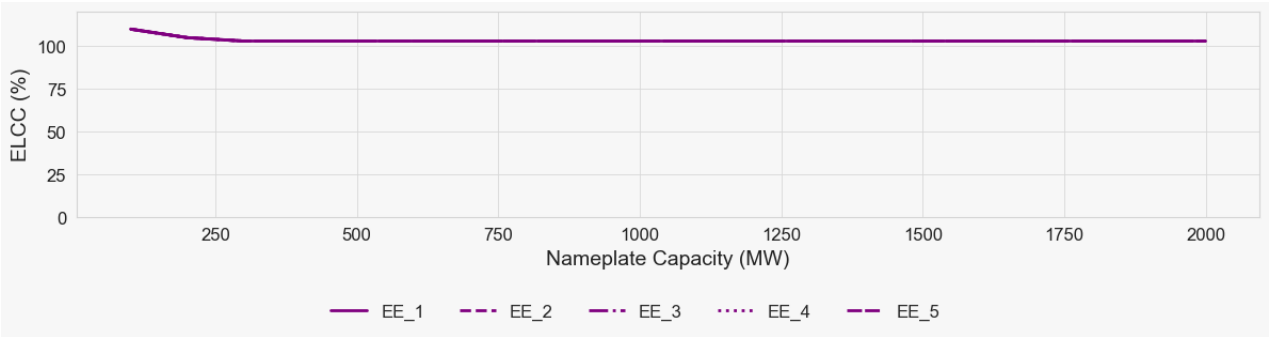


Figure 152. Energy Efficiency - Winter



G.6.4 Resource ELCCs - Tuned

A tuned ELCC measures the capacity contribution of a resource in a near adequate system. As discussed in the overview on capacity accreditation above and in the evaluation of Portfolio Reliability (see Section 7.11), complementary and antagonistic interactions between resources influence ELCCs. PGE estimates tuned ELCCs as an input into calculating the avoided cost of capacity for UM 1893.[210] Avoided cost of capacity is a measure for evaluating the cost to benefit ratio of demand side resources and helps determine what programs should be incentivized. The avoided cost of capacity is meant to inform the question: "If the system needed one less MW of capacity, what cost would the utility avoid." As this is a question of the marginal effect on the system, tuned ELCCs estimate the capacity contribution of a portfolio's most expensive resource additions in each year as if the most expensive resource were the marginal resource.[211] Tuned ELCCs are then used in a formulaic approach to approximate the shadow price of capacity in the IRP.

PGE raises concerns around the use of tuned ELCCs as part of current avoided cost of capacity definitions in UM 1893. PGE's Cost-Effective Energy Efficiency – System Benefit Analysis discussed in Appendix G.8.5 suggests these definitions are not supported empirically, such as displacement of the most expensive resource being representative of energy efficiency's marginal effect. The findings from this analysis highlight the need to continue refining methodologies to establish an

[210] https://apps.puc.state.or.us/edockets/DocketNoLayout.asp?DocketID=20999
[211] https://edocs.puc.state.or.us/efdocs/HAH/UM 1893hah347799039.pdf

avoided cost that is representative of market costs for comparable, non-emitting generating resources.

To derive tuned ELCCs, resources elected in the capacity expansion model ROSE-E are added to PGE's hourly loss of load probability model, Sequoia. The system is then "tuned" to near adequacy by adding or subtracting perfect capacity to leave a capacity need of approximately 100 MW.[212] 100 MW capacity additions of the select resources are then added to the system. Tuned ELCCs are estimated for years 2027, 2030, 2035, 2040, and 2046, then interpolated for other years of the planning horizon using a line of best fit, consistent with the recommended best practices described in UM 2011.[213]

Resources from the Continued Progress portfolio evaluated in this exercise are displayed in Table 65. Included in this table are the average of seasonal tuned ELCC by resource year which result from the methodology discussed in this section. In early years, the combined cycle combustion turbine is the most expensive resource, then three-way Wind, Solar, Storage resources, and stand-alone wind resources are listed for the bulk of the planning horizon, finally ending with long-duration storage and offshore wind. ELCCs greater than 100% reflect both direct and indirect effects of a resource addition as the resource's generation resolves unserved energy (direct) and brings sufficient energy to the system to allow other resources to more effectively reduce unserved energy (indirect).

Table 65. Continued Progress Portfolio Tuned Annual ELCCs

Resource	2027	2030	2035	2040	2046
Bat 100hr	106%	105%	104%	102%	101%
Bat 4hr	39%	36%	31%	25%	19%
CCCT	106%	104%	101%	98%	94%
Emerging	106%	104%	101%	98%	94%
Gorge Hyb	55%	52%	46%	40%	34%
MT Hyb	68%	67%	64%	62%	59%
ND Hyb	68%	66%	61%	57%	51%
SEWA Hyb	62%	56%	46%	37%	25%
Wind Gorge	30%	26%	19%	12%	4%
Wind ND	38%	36%	33%	30%	27%
Wind Off	52%	49%	44%	39%	33%
Wind Optimization	25%	25%	25%	25%	25%
Wind Repower	5%	5%	5%	5%	5%

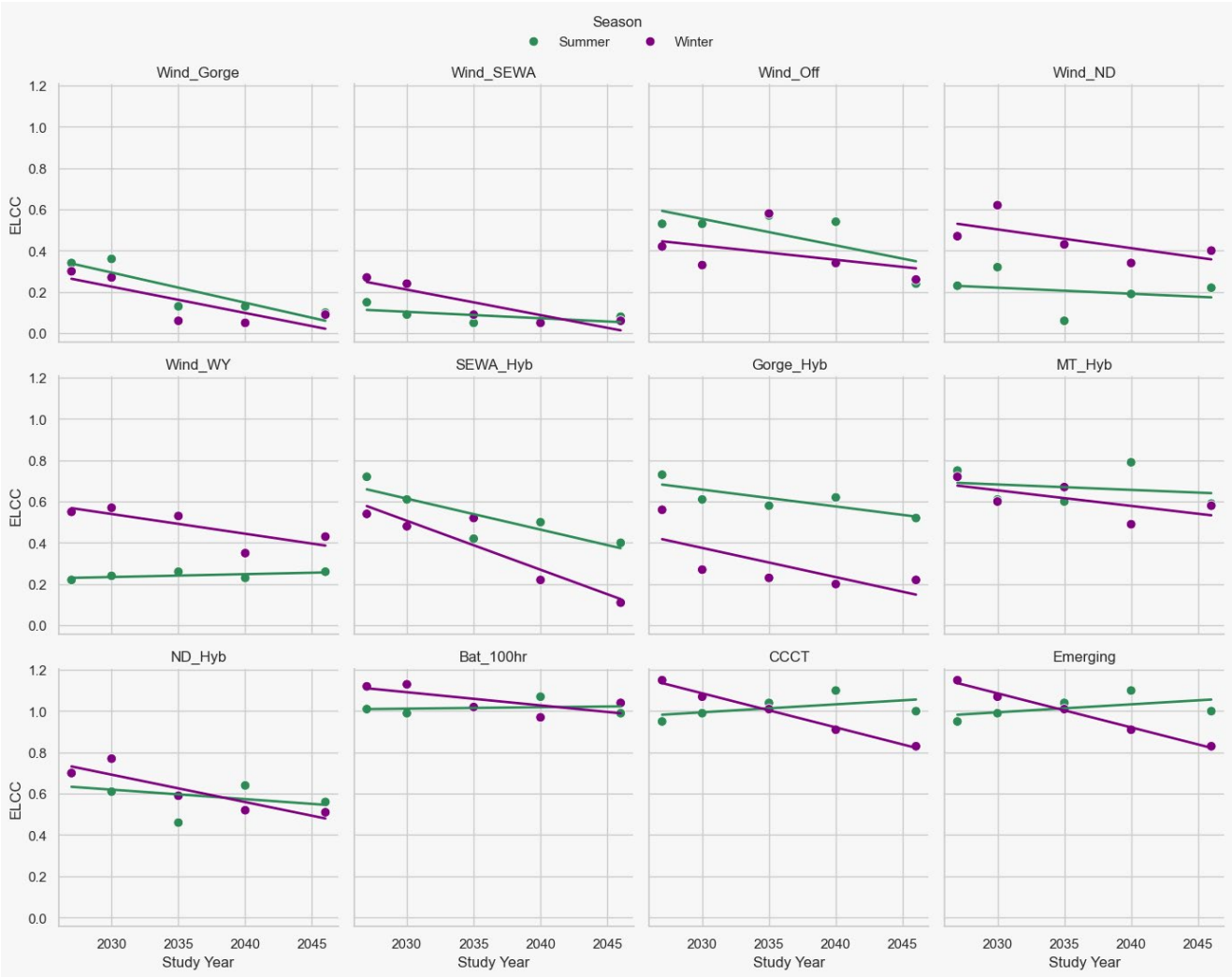
[212] A 100MW capacity need is tuned using a LOLH of 2.4 hours per year reliability metric, rather than a LOLD of .1 event days per year. This is done to increase sample size in the tuning process. System needs for the years tuned have a minimum capacity need of 96 MW and maximum of 127 MW measured in LOLH and a minimum of 163 MW and 298 MW when measured with LOLD. See EPRI's description of resource adequacy metrics for more detail on measures for estimating system reliability: https://msites.epri.com/resource-adequacy/metrics/metrics-explainers.

[213] https://apps.puc.state.or.us/orders/2022ords/22-468.pdf

Resource	2027	2030	2035	2040	2046
Wind SEWA	18%	16%	12%	8%	3%
Wind WY	40%	39%	37%	35%	32%

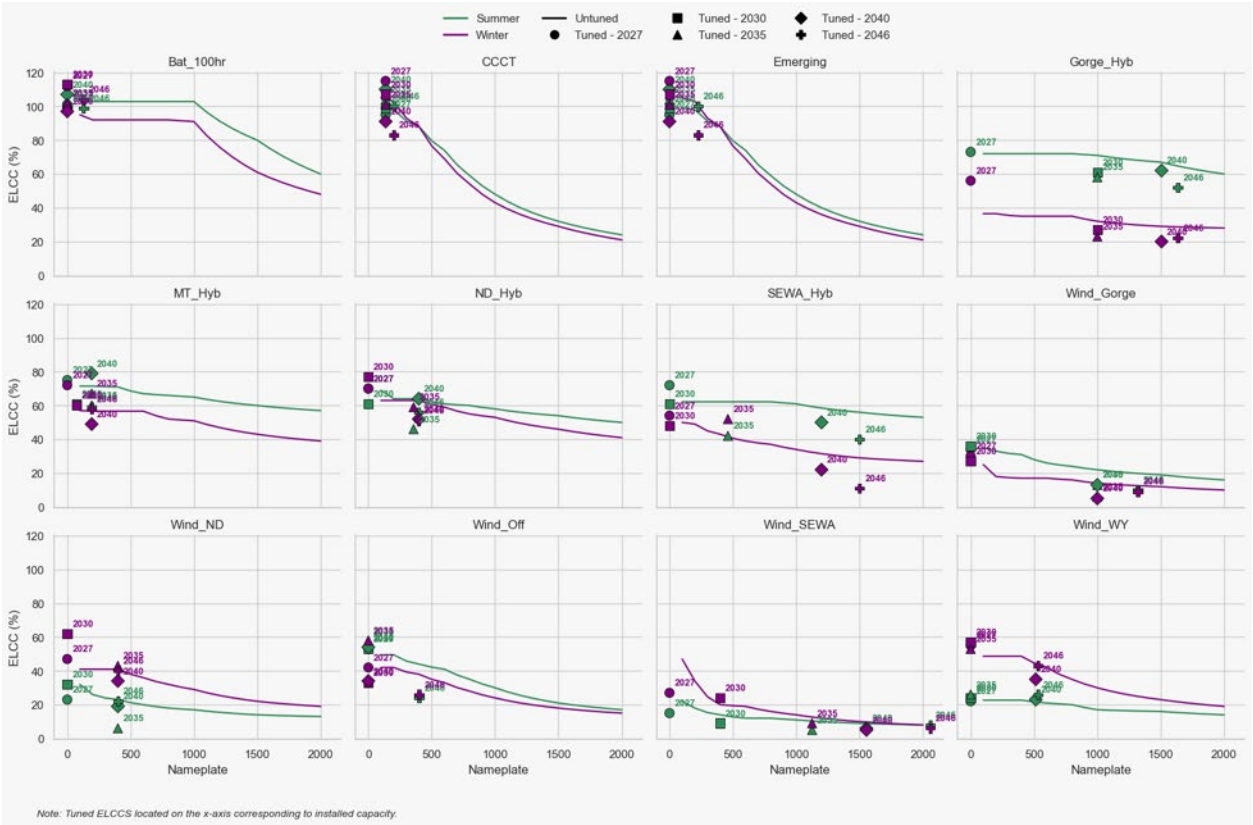
Continued Progress Portfolio Tuned Annual ELCCs are listed in Table 65. These Tuned Annual ELCCs are estimated in each of the 5 years tested, establishing a trend line showing capacity contribution of a resource as cumulative resource additions grow across the planning horizon. Figure 153, Tuned ELCCs and Interpolated Trends, shows seasonal point estimates for ELCCs in each of the simulated years and lines of best fit. This figure shows that the marginal capacity contribution of nearly all resources declines with increasing resource saturation in both Summer and Winter seasons. The only resource that shows a clearly positive trend is firm dispatchable capacity during the summer season, in the Combined-Cycle Combustion Turbine (CCCT) and Emerging resource options. However, even these firm resources see diminishing marginal capacity contributions in Winter. This finding emphasizes how greater quantities of resources additions are required to maintain resource adequacy in a highly decarbonized system as the capacity contributions resources decline with resource saturation.

Figure 153. Tuned ELCCs and Interpolated Trends



Further, Figure 154, Untuned to Tuned ELCC Comparison, plots tuned ELCCs for each of the five study years against the untuned ELCC curves used in portfolio expansion. The point values are the same as those shown above but are now located on the x-axis corresponding to the quantity of each resource's installed capacity in the portfolio. Points located below their respective seasonal untuned ELCC curve indicate antagonistic interactive effects, while those above suggest complementary interactive effects among resources in the portfolio. Comparing tuned and untuned ELCCs in this way, the figure shows that complementary interactive effects exist in earlier study years, but antagonistic interactive effects dominate as the portfolio grows across the planning horizon. These findings support the analysis discussed in the portfolio reliability assessment (See Section 7.11).

Figure 154. Untuned to Tuned ELCC Comparison



The seasonal ELCCs discussed above are averaged to produce a data set of tuned ELCC by most expensive resource for each year of the planning horizon as listed in Figure 154.

G.7 Proxy Resource Economics

The economics of resources represent a crucial element of dynamics within IRP analyses. This section describes the relevant costs associated with each proxy new resource option and summarizes the associated benefits.

G.7.1 Fixed Costs

Fixed costs for new resource options in the 2026 IRP consist of fixed capital carrying costs and fixed operating costs. Fixed cost calculations are based on resource-specific data and PGE-specific assumptions, including the cost of capital, long-term inflation and taxes. To streamline resource modeling, some components of resource cost that are technically variable in nature (they vary resource energy generation) are included in the fixed cost calculation (see Table 66). The main factor here is production tax credits (PTCs); these credits are generally associated with a fixed pattern for generation from wind facilities in PGE's dispatch modeling described in Appendix H.2.2. As a result of this dispatch modeling treatment, the annual generation of variable wind resources is known and can be assumed as a fixed quantity.

Fixed costs for new resources are incorporated into portfolio analysis by applying the levelized fixed cost (on a kW-year basis) for each year in which the resource is included in the portfolio. Levelization of fixed costs occurs over the entire economic life of each resource; these costs are specified by resource vintage (commercial operation date or "COD") to capture the effects of capital cost declines and other time-varying parameters.[214]

As discussed in G.5.1.1 above, three different capital cost scenarios (Low, Reference, High) capture a range of uncertainties in future cost declines for each technology.

Table 66. Real Levelized Fixed Cost (2026$/kW-year) COD 2030

Resource	2030	Range
Oregon Gorge Wind	207	-27% / +37%
Montana Wind	231	-31% / +33%
North Dakota Wind	206	-26% / +36%
SE Washington Wind	226	-28% / +38%
Wyoming Wind	262	-20% / +27%
Central Oregon Solar PV	253	-27% / +34%
Willamette Valley Solar PV	228	-30% / +38%
Nevada Solar PV	267	-25% / +32%
Oregon Gorge Solar PV	237	-29% / +36%
4-Hour BESS	145	-49% / +60%
6-Hour BESS	190	-50% / +62%
100-Hour BESS	563	-53% / +67%
10-Hr Pumped Hydro Storage	405	-27% / +24%
Oregon Gorge Wind Hybrid	305	-42% / +54%
Montana Wind Hybrid	402	-36% / +42%
North Dakota Wind Hybrid	382	-34% / +44%
SE Washington Wind Hybrid	400	-35% / +46%
Central Oregon Solar PV Hybrid	368	-37% / +48%
Willamette Valley Solar PV Hybrid	342	-41% / +52%
Combined-cycle Combustion Turbine	325	-36% / +48%
Simple-Cycle Combustion Turbine	200	-37% / +49%
Small Modular Reactor	1,180	-34% / +42%

[214] Commercial operation date is defined as the date after which all testing and commissioning have been completed and is the date on which a facility starts to generate power to earn revenue.

G.7.2 Variable Costs

The total levelized variable cost of candidate new resources is assessed by performing hourly dispatch simulations from 2027 to 2046 across multiple price futures. Total variable costs are composed of variable operation and maintenance costs, fuel, start-up costs, and costs of CO2 emissions, where applicable.[215] Table 67 summarizes the levelized variable costs for each resource option under the Reference Case over the economic life of each resource option. The range is represented as the below- and above-Reference deviation (or semi-deviation calculated for values both below the levelized Reference case and above the levelized Reference case value).

Table 67. Levelized variable cost (2026$/MWh) COD 2030[216]

	Reference Case	Range
Combined-cycle combustion turbine	$78	$69 - $88
Simple-cycle combustion turbine	$136	$115 - $229
Small modular reactor	$11	$11 - $11

G.7.3 Transmission Costs

Transmission options are described Appendix K.

G.7.4 Tax Credits

As discussed in Section 3.2.1, enactment of the One Big Beautiful Bill Act (OBBBA) in July 2025 changed the federal energy policy. The phaseout of tax credits for the construction (investment tax credit or ITC) and operation (production tax credit or PTC) of renewable resources has been accelerated, with timelines differing for various technology types. Tax credits are generally applied for four resource groupings:

1. Wind – Production Tax Credit
2. Solar – Investment Tax Credit
3. Energy Storage – Investment Tax Credit
4. Emerging Technology – Investment Tax Credit

The IRP modeling of tax credits for these resource types can be summarized based on the assumed availability:

Solar and wind sunset: In PGE's IRP modeling, the ITC and PTC are assumed to be available only for solar and wind projects selected through PGE's 2025 RFP Final Shortlist. These projects are represented by the proxy Gorge Wind + Solar + Storage Hybrid resource, with ITC and PTC on the respective solar and wind components available for the first 1,000 MWs of the hybrid resource

[215] All renewable resources are modeled as "must-run" with a fixed hourly shape that is varied by month as identified in Appendix Section G.5. Daily operation might impose shutdowns for system balancing reason or because of transmission bottlenecks but such events cannot be foreseen and are therefore not embedded in resource evaluation.
[216] Renewable resources and battery storage do not incur fuel costs or emit CO2. Therefore, the associated variable costs are zero and not shown in the table. The range represents the semi-deviation of variable costs across all futures.

selected in portfolio construction that are placed in service by year-end 2030. No additional solar or wind projects are assumed to qualify for ITC or PTC benefits beyond those procurements (i.e., no stand-alone solar or wind projects, and no other hybrid configurations are assumed to benefit from the solar ITC or wind PTC) in the IRP analysis.

Energy storage and emerging technology ITC continuation and phasedown: The ITC continues to be available for energy storage and emerging technology (proxied as enhanced geothermal and small modular nuclear) through the 2030s; however, the credit is subject to phasedown and eventual phaseout by the end of the decade. Specifically, PGE's IRP modeling assumes the following phasedown schedule for the ITC:

- 100% availability – In service by year end 2037
- 75% availability – In service by year end 2038
- 50% availability – In service by year end 2039
- 0% availability – In service 2040 and beyond

G.7.5 Flexibility Value and Integration Costs

Flexibility value and integration cost are critical components of variable and capacity resource economics. As defined in Appendix Q, flexibility adequacy needs encompass multiple operational value streams, including load following, regulation, spin, non-spin and renewable integration (ramping and forecast error mitigation). PGE defines flexibility value as the benefits provided by resources that help meet the system's flexibility adequacy target. Integration costs are the inverse of this benefit, generally attributed to VERs as their intermittent behavior increases the megawatts (MW) needed to meet flexibility adequacy targets.

PGE estimated the flexibility value and integration cost of new resources by partnering with Sylvan Analytics. Sylvan performed Grid Path simulations of the PGE service area.[217] When additional resources are added to the system, some new resources can be used to serve load, avoid higher-cost market purchases, and enable the re-dispatch of existing resources, thereby affecting the flexibility needs of the system. At the same time, other resources may increase the flexibility needed.

For new resource options, either a flexibility value or an integration cost is calculated by subtracting the market revenues associated with dispatching the resource from a change in the total system cost achieved by including the resource in the portfolio and dividing by the resource addition size.

PGE's estimates of flexibility values and integration costs for several new resources based on a 2030 and 2035 test year are summarized in Table 68. The difference in flexibility value between storage resources does not appear to be significantly impacted by duration, suggesting that most flexibility value is associated with flexibility constraints on short time scales (less than two (2) hours).

[217] Grid Path is an open-source modeling software developed by Sylvan Analytics (formerly Blue Marble Analytics). This model is used to perform the flexibility assessment in the 2026 IRP. Additional details on Grid Path are available in Appendix Section H.4.

Table 68. Flexibility Value (2026$/kW-year) of New Storage Resources in 2030 and 2035

Resource	2030	2035
4-hour Battery	9.80	2.20
6-hour Battery	12.50	4.00
10-hour Pumped Storage	17.00	8.70

Table 69 displays the estimated costs of integration for proxy wind and solar resources.

Table 69. Integration Costs (2026$/kW-year) of New Wind and Solar Resources in 2030 and 2035

Resource	2030	2035
Oregon Gorge Wind	7.82	10.91
Montana Wind	3.45	17.60
North Dakota Wind	3.45	17.60
SE Washington Wind	7.82	10.91
Wyoming Wind	3.45	17.60
Central Oregon Solar PV	16.92	13.10
Willamette Valley Solar PV	11.47	6.46
Nevada Solar PV	16.92	13.10
Oregon Gorge Solar PV	16.92	13.10

Hybrid resource integration costs represent the net of the component resource integration costs and flexibility values. These costs are summarized in Table 70. For wind hybrid resources, this is the net of the solar and wind integration costs and the four-hour battery flexibility value. The solar hybrid resource integration costs are the net of their respective solar integration costs and four-hour battery flexibility values.

Table 70. Integration Costs (2026$/kW-year) of New Hybrid Resources in 2030 and 2035

Resource	2030	2035
Oregon Gorge Wind Hybrid	5.67	11.35
Montana Wind Hybrid	1.66	11.07
North Dakota Wind Hybrid	1.66	11.07
SE Washington Wind Hybrid	5.67	11.35
Wyoming Wind Hybrid	1.66	11.07
Central Oregon Solar PV Hybrid	7.12	10.90
Willamette Valley Solar PV Hybrid	1.67	4.26

G.7.6 Energy Value

PGE uses the PZM to simulate economic dispatch of potential new resources. This economic dispatch takes place with electricity prices and associated risk variable inputs for each price future. Dispatchable resources generate when their dispatch costs are less than the market electricity price, subject to all modeled operational constraints, in each period.

Table 71 summarizes the Reference Case energy value and range of outcomes across the simulated price futures for each resource. These values are presented on a levelized basis, across each resource's economic life, for representative resources with 2030 commercial operation dates. As described above, the range is represented as the below- and above-Reference deviation (or semi-deviation).

Table 71. Proxy Resource Energy Value (Real Levelized 2026$/MWh) 2030 COD

Resource	2030	Range
Oregon Gorge Wind	$47	$37 - $58
Montana Wind	$55	$44 - $68
SE Washington Wind	$52	$41 - $64
North Dakota Wind	$55	$43 - $67
Wyoming Wind	$58	$45 - $71
Nevada Solar PV	$38	$30 - $50
Central Oregon Solar PV	$34	$27 - $46
Willamette Valley Solar PV	$32	$26 - $44
Oregon Gorge Solar PV	$32	$25 - $43
Oregon Gorge Wind Hybrid	$45	$36 - $57
SE Washington Wind Hybrid	$51	$40 - $63
Montana Wind Hybrid	$53	$42 - $65
North Dakota Wind Hybrid	$53	$42 - $66
Central Oregon Solar Hybrid	$46	$37 - $59
Willamette Valley Solar Hybrid	$46	$37 - $59

G.8 Net Costs and Avoided Costs

The above section summarizes costs and benefits of proxy new resource options within IRP. This section helps visualize how resource comparisons can occur outside portfolio analysis by comparing resources on a net cost basis, which becomes the basis for the avoided cost approach. Avoided costs inform UM 1893 and energy efficiency cost-effectiveness screening test and budget analyses.

G.8.1 Avoided Cost of Capacity

Portfolio analysis addresses system capacity needs through resource additions such that the resource contributions meet or exceed the model's seasonal capacity need constraints. In alignment with the last two (2) IRPs, the value of capacity outside of portfolio analysis is calculated by developing the net cost of capacity. The net cost of capacity is the cost required to get 1 kilowatt (kW) of capacity contribution from the next least cost capacity resource available to meet capacity needs, as shown.

Equation 1. Net Cost of Capacity

$$Net\ cost\ of\ capacity\ for\ 1kW\ of\ capacity\ contribution = \frac{(costs - benefits)}{ELCC}$$

Where:

$$\text{Costs} = \text{fixed} + \text{variable} + \text{transmission} + \text{integration}$$

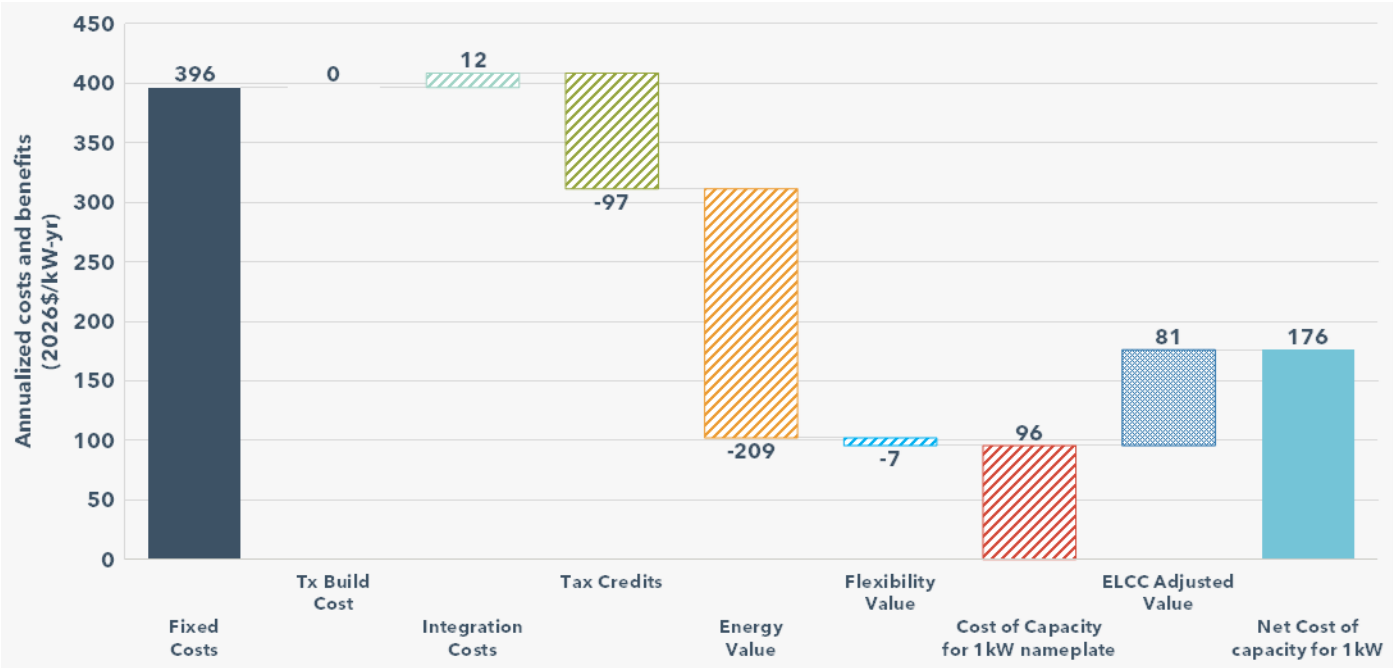
$$\text{Benefits} = \text{tax credits} + \text{energy value} + \text{flexibility value}$$

The fixed cost trajectories summarized above highlight the considerable uncertainty assumed in the future cost of new capacity resources. Table 68 shows the flexibility values assumed for new capacity resources. The ELCC of the first 100 MW of each resource is described in Appendix Section G.6.

Of the proxy utility-scale resource options available for this IRP, the Gorge hybrid resource (storage co-located with wind and solar) is the least-cost capacity resource available to meet capacity needs in the near-term to address growing capacity needs resulting from expiring contracts and load growth. Chapter 7 shows capacity added throughout time in all scenarios, with additional capacity added later in the time horizon representative of more energy-dense resources such as more hybrids, standalone wind and solar added through transmission access, as well as some longer duration storage and emerging technology. Early and ongoing additions of hybrid proxy new resources added in this CEP/IRP demonstrate that a battery alone may not be the most representative new resource option due to reliable capacity performance limitations, especially in winter months, as PGE also plans toward growing capacity needs driven by demand growth, reliability, and decarbonization targets.

The next least cost of capacity resource can also be identified by evaluating new proxy resource options based on the net cost of capacity equation. The evaluation of the net cost of capacity of a wind-solar-battery hybrid resource located in the Gorge is shown in Figure 155. The cost of capacity of 1kW nameplate is calculated as the sum of all applicable costs net of any benefits, such as tax credits. This 2030 value of $176/kW-yr represents the cost to procure 1kW nameplate of the resource. The cost to provide 1kW of capacity contribution is then calculated by adjusting the cost of capacity by the ELCC. This metric enables a fair comparison across resources. The annual average ELCC of the first increment of the Gorge hybrid resource is 54% and by dividing the $96/kW-yr cost of capacity by this ELCC, the resulting net cost of capacity of $176/kW-yr also represents the avoided cost of capacity. This ELCC adjustment shown in the figure reflects the change in value after converting from a 1kW nameplate to 1kW of capacity contribution to allow for a fair comparison across resources.

Figure 155. Deriving the 2030 Cost of 1kW of Capacity Contribution from a Gorge Hybrid Resource



G.8.2 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 this net cost of capacity of $176/kW-yr, the capacity value of a resource at a nameplate value can be calculated using the following formula:

capacity value of resource A=capacity contribution of resource A$176/kW-yr*

While not used directly for portfolio analysis, 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 net cost of capacity value is an illustrative metric and is not directly included in portfolio analysis.

Table 72 summarizes the capacity value of select proxy new resource options considered within this IRP. For capacity resources, the ELCC and corresponding capacity value (in $/kW-yr) are shown to indicate the amount of capacity required of each resource to provide 100 MW of capacity contribution. For energy resources, the ELCC and corresponding capacity value (in $/MWh) are shown corresponding to 100-megawatt average (MWa) addition sizes after accounting for corresponding levelized capacity factors.

Table 72. ELCCs and Associated Capacity Values[218]

Resource	Annual ELCC for 100 MWa Energy Addition	Capacity Value (2026$/MWh)
Wind_Gorge	24%	$13
Wind_Montana	30%	$15
Solar_Christmas Valley	21%	$15
Hybrid_SEWA	56%	$21
Hybrid_North Dakota	64%	$22
CCCT	92%	$57
Emerging	101%	$30
Resource	**Annual ELCC for 100 MW Capacity Addition**	**Capacity Value (2026$/kW-yr)**
4-hr Battery	29%	$51
100-hr Battery	97%	$172
Pumped Storage	56%	$98

G.8.3 Clean Resource Energy Cost

Prior to the first CEP, production cost and capacity expansion models used for portfolio analysis could rely on the market to meet energy needs based on assumed market prices. HB 2021 sets emissions targets, which are applied as emission constraints in the IRP. These constraints limit access to both specified and unspecified market purchases in the wholesale market that have embedded carbon content.[219] Thus, if the total energy needs of the system surpass the energy generated by both the existing non-emitting resources and the carbon-embedded energy, the model must rely on adding incremental generating resources to meet energy need. This represents a new cost associated with meeting energy needs through non-emitting resources. Conversely, this is a value to resources that avoid this new cost. Within the IRP's portfolio analysis, these costs are accounted for; decisions about new resource additions fairly estimate all the costs and benefits associated with each potential supply-side option. However, the costs and benefits of many resources are currently estimated outside of the IRP. Current methods estimate energy value in one of two (2) ways:

1. The first relies on previous assumptions about market access.[220]
2. The second involves determining the net cost of a new off-system VER.

However, this option is only applied to resources assuming available transmission capacity. If either of these methods is applied under the constraints that PGE faces today, they could significantly

[218] The annual ELCCs shown in this table are calculated as the average of the seasonal ELCCs 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.
[219] Oregon Department of Environmental Quality (ODEQ) greenhouse gas (GHG) reporting rules (under ORS 468A.280) assign emissions to unspecified sources of energy that serve Oregon retail load.
[220] Generally involving summing the hourly product between generation and market prices.

underestimate the energy value of potential new resources. Doing so would lead to a misidentification of resource economics, resulting in a higher cost system. The existing emissions and transmission constraints signal a need to reassess which values are used when comparing the costs of resources outside the IRP. Additional study is required to understand how estimating a new resource's energy value should be calculated outside the IRP.

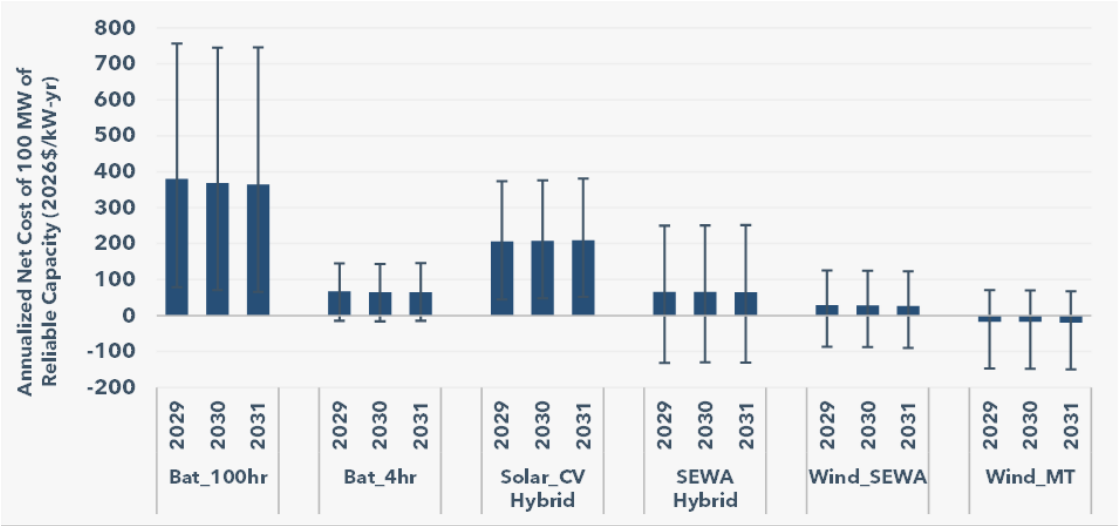
G.8.4 Resource Net Cost

Appendix Section G.8.2 above applies the net cost concept for new additions to assess capacity value. In this section, the net cost concept is applied to visualize the relative economics between resources and the dynamics seen within portfolio analysis. 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. This approach is consistent with common industry practice when evaluating resource economics.

In this section, the net cost of new additions is defined as the sum of all costs, such as fixed, variable and integration costs, net of any benefits, such as tax incentives, and any value provided to the portfolio, including energy, flexibility, capacity values. These net costs are based on the formula described in Appendix Section G.8.1 above. Based on these illustrative results, portfolio analysis discussed in Chapter 7 meets capacity needs more economically with energy / hybrid resources in select years. Below are visualizations of the net cost of different capacity (in $/kW-yr.) and energy resources (in $/MWh).

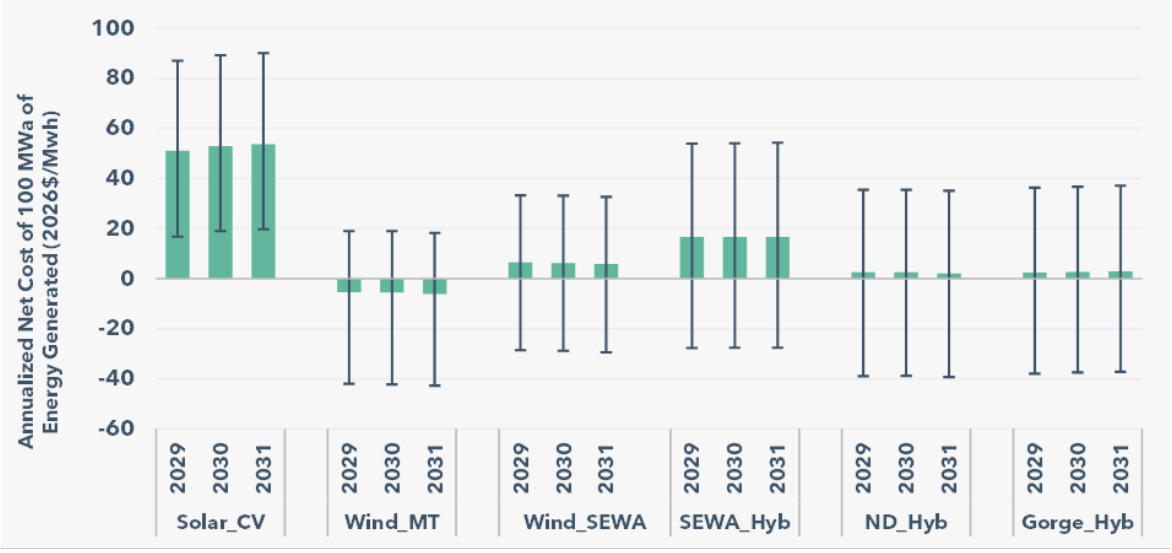
Figure 156 visualizes the net cost in $/kW-yr of providing 100 MW capacity contribution to the portfolio from various select resources. From this snapshot, wind resources without added transmission costs appear to be the least-cost means to provide capacity to the portfolio in the near-term. The relative net costs across resources highlight the order for selection in portfolio analysis. For example, with new transmission and access to some other resources beginning after 2032, based on the information in the figure, a model adding capacity while minimizing cost would select most of these resource options before any of the transmission expansion options.

Figure 156. Net Cost for 100 MW of Capacity Contribution of Capacity Resources by Near-Term COD



Similarly, Figure 157 visualizes 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. The resources shown do not include any that require transmission access, which have associated costs beginning 2032 for certain resources, as relevant. 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 157. Net Cost for 100 MWa of Renewable and Hybrid Resources by Near-Term COD



G.8.5 Cost Effective Energy Efficiency Thresholds – EE System Benefit Analysis

G.8.5.1 Introduction

The following section describes an analysis conducted by PGE to further ongoing discussion relating to methodologies for estimating energy efficiency (EE) cost-effectiveness as part of UM 1893, and in response to OPUC direction on Staff's recommendation #4 in Order No. 24-096.[221]

The results of this Energy Efficiency System Benefit Analysis (EESBA) lead PGE to conclude that the current methodology used in UM 1893 overestimates the cost-effectiveness of EE. Current practices attempt to forecast twenty years of EE cost and benefits without adequately accounting for significant uncertainty and risks associated with actual savings. As a result, estimates of EE cost-effectiveness may diverge materially from realized outcomes. Without accounting for forecast error in EE benefits, the OPUC risks committing customers to pre-pay, or revenue finance, more expensive EE measures that ultimately deliver savings below forecast. PGE notes that these concerns can be effectively managed by estimating EE cost-effective thresholds based on actual market costs of comparable, non-emitting generation resources. Alternatively, PGE believes a more comprehensive examination of cost-effective EE methodology is warranted. Such an examination is

[221] https://apps.puc.state.or.us/orders/2024ords/24-096.pdf#page=21.

particularly important because the current methodology does not account for the affordability thresholds established by HB 2021.

G.8.5.2 Conclusions

To best measure EE cost-effectiveness thresholds for the 2026 CEP/IRP, PGE's EESBA assessed the impacts of a hypothetical addition of EE to PGE's portfolio. By using PGE's portfolio capacity expansion model, the EESBA measures the benefit of EE to system costs across the IRP planning horizon, including energy, capacity, and transmission impacts. The results from this analysis are consistent with the formulaic approach currently prescribed by the OPUC in UM 1893.[222]

Overall, PGE's EESBA described in this appendix concludes:

1. EE provides demonstrable benefits for customers in all years and scenarios studied, reducing the amount of generating resources PGE needs to procure.
2. EE cost-effective thresholds differ by year. Cost-effective thresholds are modest in the near term and significantly increase beyond the Action Plan period in 2032. PGE asks that the OPUC provide guidance on the inclusion of forecasted costs beyond the action plan including additional discount factors for uncertain, post action plan savings.
3. EE cost-effective thresholds are dramatically impacted by the assumed regulatory structure (i.e. HB 2021 Glidepath or Continued Progress / Reliability Only). Intuitively, the EESBA shows that EE cost-effective thresholds are elevated when portfolios are constrained to meet HB 2021's emission targets. However, affordability protections included in HB 2021 must be considered before committing to EE cost-effectiveness tied to emission driven compliance.
4. EE cost-effectiveness thresholds are highly uncertain, varying across planning scenarios and studied futures. Without accounting for the distribution and uncertainty of cost-effectiveness thresholds, the OPUC risks committing current customers to pre-pay for measures whose savings may not arise.
5. EE additions generally do not impact least cost transmission selection. The stability of transmission results is driven by the need for capacity and energy from the related generating resources which EE does not wholly displace. The limited impact of EE on transmission selection suggests that EE generally does not eliminate or significantly defer the need for transmission. Transmission avoidance should not be a significant driver and input into calculations of EE cost-effectiveness.
6. A predetermined marginal resource, such as the highest-cost resource in a given year, does not accurately reflect the marginal changes occurring within the system. The marginal change to the system from additional EE affects multiple resources –displacement is not limited to the most expensive generation resource. The system re-optimizes the addition of EE by changing procurement decisions for a variety of resources, including cheaper stand-alone solar and wind, and more expensive firm resources.

[222] https://edocs.puc.state.or.us/efdocs/HAH/um1893hah348561039.pdf

The findings from the EESBA highlight the risks associated with the inherent uncertainty in using a 20-year forward-looking costing analysis derived from the HB 2021 Preferred Portfolio. The findings also raise concerns around specific methodological presuppositions in current UM 1893 requirements that are not supported empirically.[223] The results highlight the need to continue refining methodologies to establish an EE cost effectiveness framework that accounts for anticipated portfolio costs.

G.8.5.3 UM 1893 Background

Utilities must file energy efficiency avoided cost data reports annually in OPUC Docket No. UM 1893 for use in Energy Trust of Oregon (ETO) planning. The annual submission is based on the most recent IRP data and results, with methodology set by OPUC. The data is used to update utility energy efficiency program budgets, collected through customer ratepayer charges.

Data in the annual submission primarily relates to 20-year forecasts regarding avoided costs of capacity, energy, and transmission. The methodological instructions set by OPUC are prescriptive and inherently presume that investment in EE defer investment in the most expensive energy generation, capacity, and transmission resources. It is PGE's understanding that ETO combines these value streams together and across electric utilities for use in its cost-effective screening test to inform their budget. PGE is not counseled on the ETO's methodology on how these data submitted in UM 1893 are ultimately used.

Broadly, the current UM 1893 methodology is not aligned with IRP portfolio analysis. While the submission relies on IRP data, it does not represent IRP findings. Revisiting the methodology is part of ongoing discussions within the UM 1893 docket and was sought by OPUC in PGE's last IRP docket LC 80 Order No. 24-096.[224]

OPUC's current avoided cost methodology and ETO's budget framework do not account for the risks of EE benefit forecast error. While PGE understands the important role that EE plays in decarbonizing the energy system and supporting reliability and affordability for customers, PGE continues to request that the methodology utilized in UM 1893 be revisited and refined to ensure that the avoided cost reflected in customer prices and leveraged in procurement decisions is as representative as possible.

G.8.5.4 Methodology of EE System Benefit Analysis

PGE used its capacity expansion model, ROSE-E, to estimate the change in system costs from the addition of five (5) MWa of PGE's proxy EE Bin 1 resource to the GHG Glidepath (GHG) and Reliability Only (RO) scenarios (EE Addition case).[225] The EE volumes are added without additional fixed costs. By comparing the annual costs of the EE Addition case to their respective base case scenarios, discussed in Chapter 7, the annual system benefit of EE is calculated.

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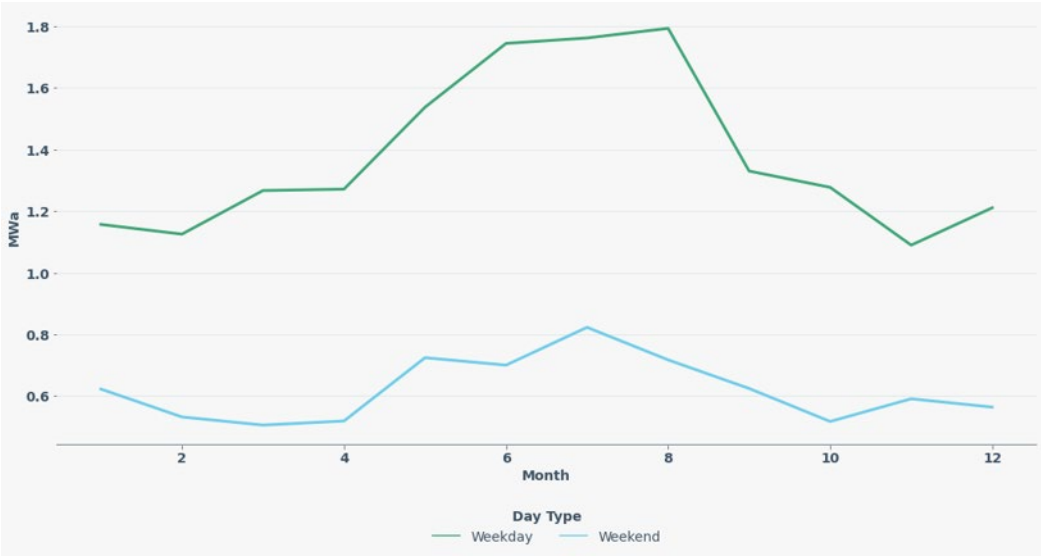
[223] In accordance with UM 1893 requirements, PGE annual files an updated data template on October 15 in that docket. This year's filing will be based in data from this 2026 CEP/IRP.
[224] https://apps.puc.state.or.us/orders/2024ords/24-096.pdf#page=21
[225] EESBA of the GHG Glidepath scenario does not include the additional resource requirements to meet emission targets under hourly emissions analysis, as discussed in Appendix Section H.2.1.7.

The annual system benefit of EE is equivalent to the cost-effective threshold for EE. For values under this threshold the additional fixed cost of EE is less than system savings—specific to the utility cost test relevant for the IRP.[226] By comparing the EE Addition case to the base case within the IRP model, the EESBA captures IRP relevant system benefits of EE including reduction of energy need resources, reduction of capacity need resources, and reduction of transmission needs. Consistent with IRP methodology, EESBA measures changes in generation and transmission resource buildout, NPVRR, and annual costs across the 333 futures simulated for each scenario.

Figure 158 depicts the monthly capacity factor of the EE resource used for the EESBA. The shape is of the EE Bin 1 Proxy resource (see Appendix Section G.1 – Non-cost-effective Energy Efficiency), the same as used in ROSE-E for capacity expansion in this IRP. Within the EESBA EE Addition case, the fixed cost of the EE addition is zero. Within both the EE Addition and base case, the model is also able to select the EE Bin 1 resource at $129/MWh with 2 MWa of cumulative market potential by 2031.[227] In the EESBA EE Addition case, energy needs were reduced by 5 MWa multiplied by the capacity factor of the resource. For example, the EE Addition case required approximately 5 and 7.5 MWa less energy for January and August, respectively, than the base case. Seasonal capacity needs were 5.15 MW less in the EE Addition case, as the ELCC of the EE Bin 1 resource estimated for the 2026 CEP/IRP is 103%.[228]

Figure 158. EESBA EE Proxy Resource



[226] https://www.energytrust.org/wp-content/uploads/2016/11/GEN_FS_CostEffectiveness.pdf
[227] EE Bin 2, the second most affordable energy efficiency proxy resource has average fixed costs of $2,391/kW-yr. and 9.7 MWa of cumulative potential by 2031. Its capacity factor is slightly higher in winter (1.2 in January) and less in summer (1.3 in August), with the same ELCC of 103%. See Appendix Section G.1.
[228] An ELCC of greater than 100% is representative of the capacity and energy interactions captured in loss-of-load modeling. It can be interpreted as having a 1:1 reduction in hour of greatest capacity shortfall, and a reduction in energy need across other hours that either directly reduce loss of load, or allow other energy limited dispatchable resources to better optimize to resolve unserved energy in hours shouldering the greatest capacity shortfall.

Additional EESBA sensitivities tested the seasonal capacity and energy benefits of a potential EE resource. For these four sensitivities, energy or capacity needs were reduced by a flat 5 MWa (MW) for either summer or winter.

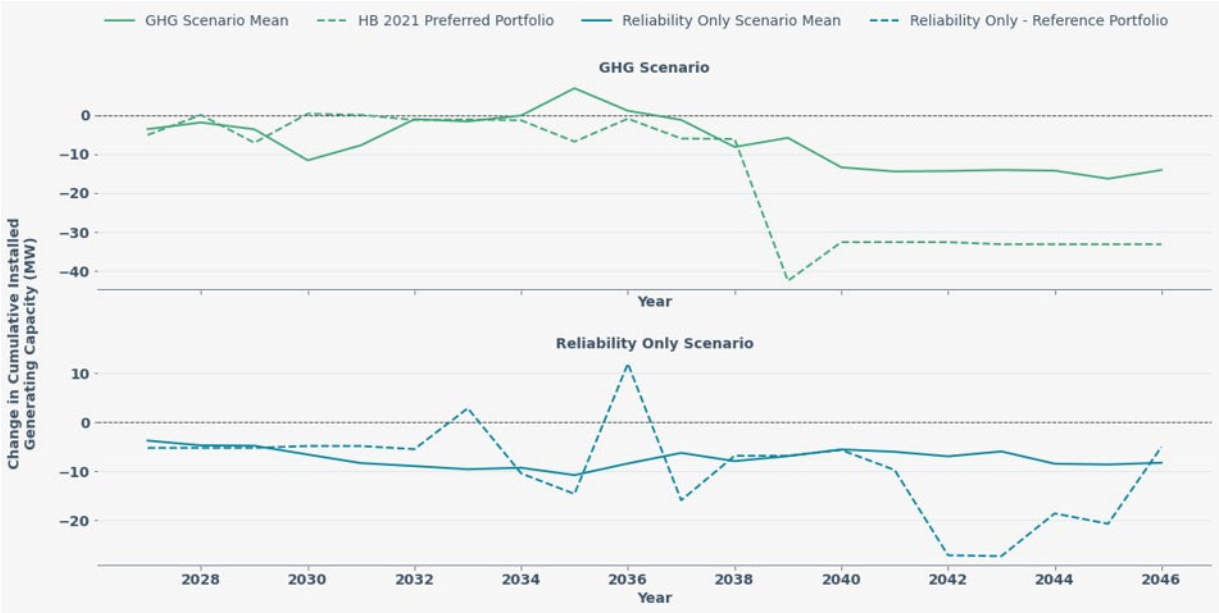
The costs in the EE Addition case are differenced from the base case for each GHG or RO scenario and unitized to $/MWh, resulting in a cost-effectiveness threshold as a measure of NPVRR and annual costs as reported in ROSE-E. Resource buildouts are also compared across the base case and EE Addition capacity expansion results to understand the changes in resource procurement resulting from the EE addition.[229]

G.8.5.5 Findings

Energy Efficiency Additions Reduce Resource Need Across the Action Plan

The EESBA confirms a central premise of EE cost-effectiveness analysis including UM 1893, EE resources displace the need for supply side resources. Provided the cost of EE savings are lower than the cost of supply side resources, such additions contribute to lower customer costs. Figure 159 identifies the total change in nameplate capacity of generation resources in the EE Addition case compared to the base case. The specific resource change by year is identified for the HB 2021 Preferred Portfolio and RO reference portfolio. Additionally, the average resource change across the 333 futures is illustrated. Results show that on average EE additions reduce generation resource needs across the broad range of evaluated futures.

Figure 159. Change in Cumulative Total Generation Resource Buildout - EE Addition



[229] Annual costs do not include changes in energy fill or capacity fill resources which may be present in early years of the simulation in some futures, and as such measure costs specific to steel in the ground resource procurement.

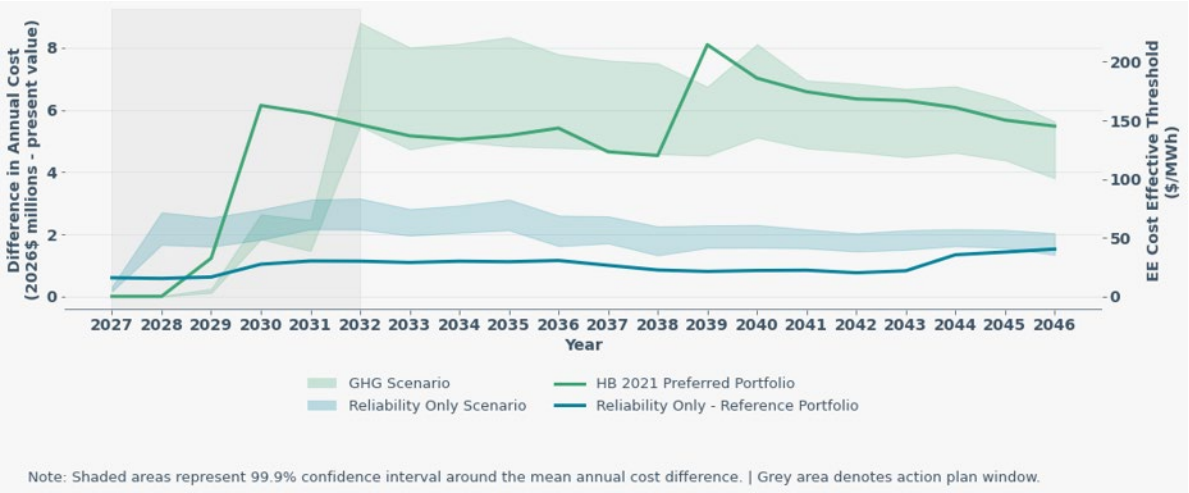
Energy Efficiency Savings Are Concentrated After the Action Plan

Most EE savings for the GHG scenario result from changes in resource procurement made after the action plan period ends in 2032. For the RO scenario, savings remain comparably modest and flat. There are several important implications of this finding. As observed in Figure 160, EE savings increase in the GHG Scenario after 2032, even though the portfolio is designed to meet the GHG reduction target in 2030. This suggests that EE savings under a GHG scenario are not simply related to meeting GHG targets. Instead, savings are significantly impacted by longer range uncertainties including generation resource tax credit expiration assumptions, assumed declines to resource capacity contributions, long-term load forecasts including datacenter growth, and uncertain transmission expansion actions.

As approved OPUC cost- effectiveness methodologies include resource planning inputs for the full planning horizon, the methodologies necessarily assume that energy efficiency avoids investment costs for which the utility has not requested acknowledgment. Additionally, as observed in the expanding confidence interval of the mean, the magnitude of savings beyond the action plan period are uncertain and difficult to predict. Continued use of existing UM 1893 inputs implicitly assumes that these post-2032 EE cost savings occur and leads to budget setting activities committing existing customers to pre-pay for measure costs that might not be justified given uncertainty of actual savings. PGE asks that the OPUC provide guidance on the inclusion of forecasted costs beyond the action plan.

To diminish the risk of benefit overestimation, the OPUC could consider additional discount factors for post action plan savings or use of EESBA type methodology. Use of a EESBA methodology allows for inclusion of a distribution of outcomes. For example, 25th-percentile value provides a more conservative estimate of future EE savings. Seventy-fixe percent of observations in the distribution are at or above the estimate, increasing confidence that the actual savings will meet or exceed the forecast.

Figure 160. Annual Avoided Costs Across IRP Scenarios and Futures



Avoided Costs are Highly Uncertain Across Planning Scenarios and Futures

Current methodology in UM 1893 does not include ranges and risks included in IRP methodology. UM 1893 derives capacity, transmission, and energy avoided costs directly from the HB 2021 Preferred Portfolio, a single outcome of a future planning scenario that in the IRP also includes 333 possible futures. Anchoring avoided costs to the Preferred Portfolio ignores the uncertainty that is fundamental to PGE's IRP analysis including the range of load forecasts, technology costs and market futures.

The broad distribution of EE cost effectiveness results demonstrates the risk and likelihood of overestimating forecasted EE benefits. Figure 161 illustrates the distribution of 20-year cost effectiveness results for 333 futures in each RO and GHG scenarios. The HB 2021 Preferred Portfolio, elected from the GHG Scenario, has a cost-effective threshold of $211/MWh, while the Reliability Only – Reference Case Portfolio has a cost-effective threshold of $41/MWh. In the GHG scenario the variation in cost-effectiveness is broad and skewed to the right, ranging from $4/MWh to $852/MWh with a median of $105/MWh. The distribution of cost-effective thresholds in the RO scenario has a similar shape, ranging from $5/MWh-$293/MWh with a median of $48/MWh.

Figure 161. Uncertainty in Avoided Costs

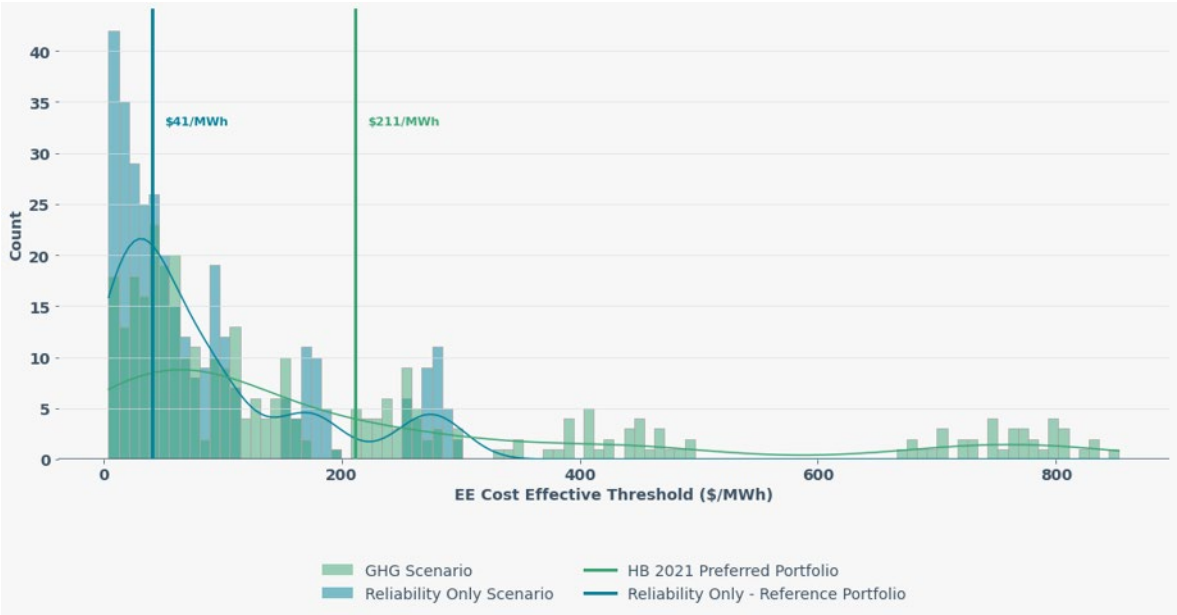
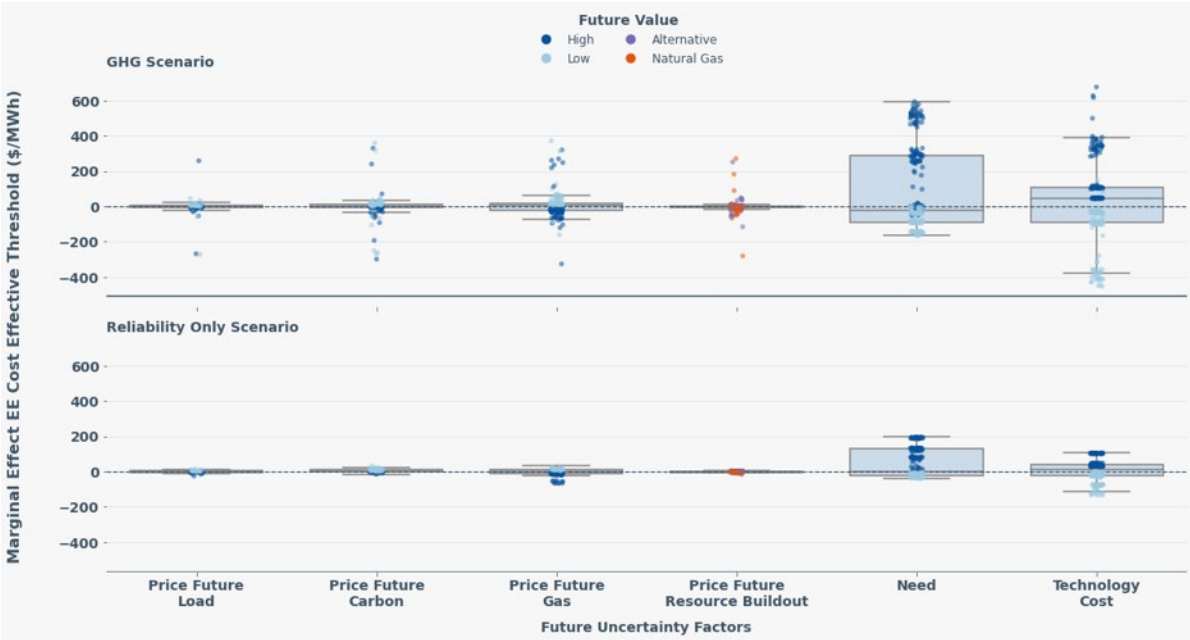


Figure 162 shows the factors driving future uncertainty in cost effectiveness. The plot shows that Need and Technology Cost futures have the largest marginal effect on the cost-effective threshold. Intuitively, the cost-effective threshold is greatest in High Need and High Technology Cost futures. Comparing the results in Figure 162 to the distribution of avoided costs in Figure 161 above, the three increasing step changes in avoided costs for either scenario arise from increases in Need, Technology Costs, or interactions between the two.

Figure 162. Marginal Effects of Future Factors on Avoided Costs



The uncertainty discussed above emphasizes the likelihood of forecast error in estimating EE cost-effective thresholds. While forecast error is a relevant issue for any supply side investment decision, EE cost-effectiveness studies are unique as forecast error can directly contribute to higher procurement costs. The cost-effectiveness of EE has a direct role in setting expenditure budgets, so it is important to introduce measures of conservatism (ex. 25th percentile) to account for the risk of overestimation.

In comparing the above results for GHG and RO scenarios, UM 1893 methodologies must be revisited to account for differences in regulatory structures associated with HB 2021. The 2026 IRP identifies a Continued Progress HB 2021 compliant plan that does not reach HB 2021 emission reduction targets within the Action Plan period. Although the EESBA does not test a Continued Progress scenario, cost-effectiveness thresholds are comparable to Reliability Only results as both scenarios have equivalent energy and capacity needs with access to the same resource options.

Additional EE spending beyond Reliability Only thresholds should be justified by analysis demonstrating those expenses maximize year one marginal emissions reductions. While regulatory discussion regarding HB 2021 Section 10 continues, PGE recognizes that prudent expenditures should maximize emission reductions given a limited 6% revenue requirement impact. Energy efficiency spending beyond RO cost-effective thresholds may undermine this objective and diminish overall emission reductions.

EE Displaces Blend of Generating Resources and No Transmission in Preferred Portfolio

UM 1893 definitions rely on annual and resource specific assumptions of the Preferred Portfolio to calculate avoided costs related to the energy, capacity and transmission deferral benefits of EE. The EESBA tests whether the assumptions embedded in these definitions are empirically supported. The findings below indicate that EE does not displace procurement of the most expensive energy

or capacity resource in every year of the Preferred Portfolio and does not defer transmission procurement in any year of the Preferred Portfolio. These findings are contrary to current UM 1893 methodologies.

As shown in Figure 159, the addition of EE in the EESBA does displace a measurable quantity of generating resources across the planning horizon. Table 73 highlights the resource specific changes in the HB 2021 Preferred Portfolio in 2039, the year with the greatest cumulative difference between the EE Addition and base case buildouts. Observations are limited to resources that entered either the base case or EE Addition portfolio in year 2039 or had a non-zero cumulative difference between the buildouts. By 2039, six (6) generating resources in the EE Addition case have different quantities than the base buildout for a total of 43 MW less capacity, as shown in Figure 159. Importantly, the EE Addition case includes the same quantity of 100-hour batteries, the most expensive resource to enter the portfolio in 2039, and transmission as the base case. The EE addition has displaced hybrid resources and standalone short-duration storage in favor of increased standalone wind.

Table 73. Changes in HB 2021 Preferred Portfolio Resource Buildout – 2039

		Cumulative Installed Capacity (MW)			Year-Over-Year Installed Capacity (MW)		
Year	Resource	Base Case	EE Addition Case	Difference	Base Case	EE Addition Case	Difference
2039	**SEWA Hyb**	1567	1563	-5	489	486	-3
2039	**B2H**	400	400	0	400	400	0
2039	**SWIPN**	400	400	0	400	400	0
2039	**Bat 4hr**	262	228	-33	262	228	-33
2039	**Bat 100hr**	267	267	0	100	100	0
2039	**SEWA Hyb (CF)**	432	391	-40	0	0	0
2039	**Wind SEWA (CF)**	948	989	40	0	0	0
2039	**Winter Colstrip FOT**	116	108	-8	0	0	0
2039	**Winter WSPP FOT**	162	165	3	0	0	0

Table 74 shows annual values of cumulative installed capacity for transmission projects elected in the HB 2021 Preferred Portfolio. Both quantity and timing of procurement are the same in the base case and EE Addition case indicating that the proxy EE does not defer transmission procurement in this specific resource buildout.

Table 74. Comparison in HB 2021 Preferred Portfolio Transmission Buildout

	Year							
HB 2021 Preferred Portfolio	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
Base Case	0	1000	1270	1815	4145	5245	5245	5245
EE Addition Case	0	1000	1270	1815	4145	5245	5245	5245

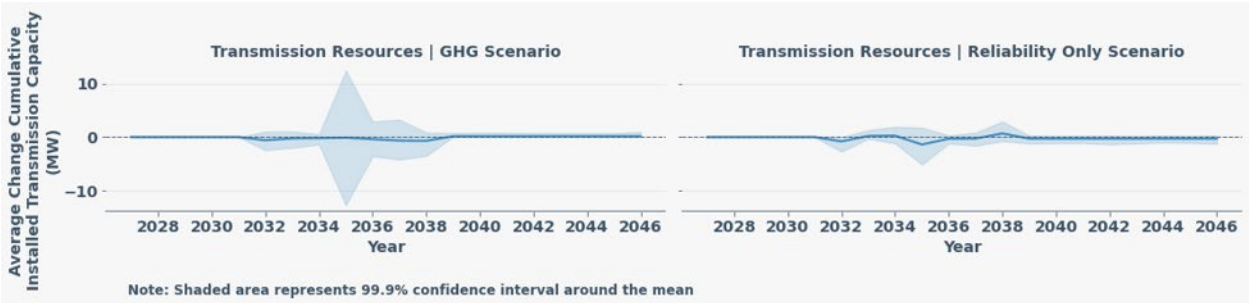
	Year							
Difference	0	0	0	0	0	0	0	0
	Year							
HB 2021 Preferred Portfolio	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**
Base Case	6045	6045	6045	6045	6045	6045	6045	6045
EE Addition Case	6045	6045	6045	6045	6045	6045	6045	6045
Difference	0	0	0	0	0	0	0	0

Figure 163 shows on average resources are traded across all futures similarly to what is displayed for the HB 2021 Preferred Portfolio in Table 73, above. On average hybrid resources are exchanged for standalone wind resources and Li-Ion Batteries are more likely to be exchanged than more expensive firm energy (Emerging) or long-duration storage resources (Long-Duration Battery).

Figure 163. Average Change in Resource Specific Cumulative Buildout in EE Addition Case

Figure 163 suggests the HB 2021 Preferred Portfolio results discussed in Table 74 are also representative for transmission buildouts in both scenarios on average. The EE addition causes a roughly equal chance of incurring or deferring transmission capacity during years between 2034 and 2038.

Figure 164. Average Change in Resource Specific Cumulative Buildout in EESBA from Factual



UM 1893's current definitions of avoided costs for both energy and capacity identify the marginal effect of EE as displacing the resource with the greatest net cost. This presupposes that cost is the driving constraint in capacity expansion and that EE has a direct effect on a particular resource. In capacity expansion, resources are procured to minimize costs with respect to other constraints such as capacity and energy needs. Changes to these needs in an avoided cost estimation reflect the energy and capacity benefits specific to an EE resource. Results above suggest that as EE relieves capacity needs and reshapes energy needs, cheaper resources are exchanged to meet system constraints at the lowest cost while the more expensive resources that bring firm energy and capacity remain optimal.

G.9 Long Lead-Time Resources

Long lead-time resources represent options that potentially require lengthy planning and construction periods relative to those assumptions for proxy standalone solar PV, onshore wind, or lithium-ion BESS. This longer development runway may create challenges for identifying and selecting these resources in a standard utility planning and procurement process as their availability timing may not align with the windows used in those processes. The timing misalignment may diminish the market signal to project developers. PGE recognizes the potential benefits these resources may bring and seeks to strengthen those market signals that encourage development of new resources.

Within the context of decarbonization mandates and evolving grid dynamics, expanding the resource stack to include additional, emerging, technologies may prove necessary for maintaining a "least-cost, least-risk" system. These resources possess potentially unique operational and physical attributes that provide system-level benefits, most notably the diversification of regional supply. In financial and utility planning frameworks, diversification is a core principle of optimal asset allocation, mitigating the correlated performance risks associated with an over-reliance on a narrow set of resources.

Utility-scale pumped hydro storage and multi-day long-duration battery energy storage are represented using proxy resources within this IRP. To analytically capture these capabilities within the current modeling cycle, the costs, operational parameters, and economic attributes of an "emerging technology" class of resources are included in the portfolio construction process. This designation specifically encompasses non-emitting, flexible, and firm generation represented by

next-generation geothermal and small modular reactors (SMRs). Beyond these technologies, the long lead-time definition also captures capital-intensive resources including alternative battery chemistries, long-duration energy storage, carbon capture and sequestration, and low- or non-emitting fuels.

Appendix H IRP Modeling Details

H.1 AdopDER

AdopDER is a Distributed Energy Resource (DER) locational forecasting methodology built on a hybrid top-down and bottom-up structure. From top-down, the model aligns with segmentation, weather assumptions, and growth trajectory of the CLF to ensure consistency in underlying drivers of load. From bottom-up, AdopDER simulates DER adoption and load growth at the site-level using a stock turnover framework that accounts for customer characteristics, equipment replacement cycles, and technology eligibility. Adoption is further informed by market adoption curves and policy drivers, with probabilistic elements incorporated to reflect uncertainty in customer behavior and program participation. This structure allows the model to represent both deterministic adoption trends—such as known load additions—and probabilistic adoption trends across the broader customer base.

Bottom-up inputs to AdopDER include a comprehensive set of locational and customer-specific data. These inputs include historical load trends, customer segmentation, building and zoning activity, known development and redevelopment projects, DER interconnection queues, and anticipated changes in end-use technologies such as air conditioning, electric vehicles, and electric heating. Known, high-probability load additions—referred to as spot loads—are explicitly modeled at their expected locations within the system, including large commercial and industrial developments and known electrification projects. Remaining load growth and DER adoption, which are more uncertain in nature, are distributed across the system based on historical patterns, customer characteristics, and adoption likelihoods. This distinction between known and forecasted additions allows AdopDER to capture both near-term certainty and long-term uncertainty within the same modeling framework.

AdopDER develops hourly forecasts by first establishing a baseline load profile and then layering incremental impacts from electrification and DER adoption. Baseline load is derived from historical meter-based consumption and normalized using weather-adjusted methodologies to separate heating, cooling, and base load components. These normalized load components are then projected forward using representative weather assumptions to create a baseline hourly load forecast. Incremental impacts from DERs and electrification technologies are applied using technology-specific performance assumptions and hourly shapes. For example, transportation electrification is modeled using charging profiles that reflect expected customer behavior, while solar PV generation is modeled using resource-based production profiles. This process results in annual (8760) hourly load shapes that reflect both the magnitude and timing of load changes over time.

The model produces outputs at multiple spatial resolutions, including service-point, feeder, substation, and system levels. At the locational level, AdopDER captures the clustering of DER adoption and load growth, which is critical for understanding localized impacts and non-coincident peak behavior. These locational forecasts are then aggregated to the system level for IRP modeling. Importantly, the aggregation process preserves diversity in load shapes and peak timing, resulting in system-level forecasts that more accurately reflect underlying customer behavior compared to

uniform allocation methods. The outputs include baseline DER adoption and incremental load impacts by technology which are used as inputs to IRP models.

In addition to passive load impacts, AdopDER quantifies the availability and characteristics of flexible DERs, including demand response and storage-enabled load shifting. These resources are derived from the same underlying adoption forecasts and are translated into resource potential for use in IRP modeling. This includes estimating the timing, magnitude, and duration of load flexibility that can be deployed through a virtual power plant (VPP) framework. These outputs are structured to be compatible with IRP modeling tools, enabling representation of demand-side resources alongside traditional supply-side resources.

Weather is incorporated into AdopDER in both the development of baseline load and the modeling of DER performance. Historical load is normalized using representative weather conditions, and forward-looking forecasts are based on normalized weather datasets that reflect expected conditions over the planning horizon. The model also has the capability to evaluate multiple weather scenarios, allowing for assessment of variability and potential impacts of extreme conditions on both load and DER performance. Solar generation modeling incorporates resource-specific inputs to estimate hourly production profiles, ensuring consistency between load and generation assumptions.

Finally, AdopDER outputs are calibrated to the corporate load forecast to ensure alignment with system-level energy and peak demand expectations. This calibration reconciles the bottom-up forecast with the CLF by adjusting aggregate results while preserving locational detail and non-coincident peak characteristics. The methodology behind the CLF is represented in Section Load Forecast Methodology. The result is a set of hourly load forecasts and DER adoption outputs that are internally consistent across spatial and temporal scales. This ensures that IRP modeling reflects a unified view of future load that integrates detailed customer-level adoption behavior with system-level planning requirements, providing a robust foundation for evaluating resource needs, portfolio performance, and system reliability.

Table 75. Summary of AdopDER Updates & Inputs Since 2023 CEP/IRP Update

Category	Update	Description & Source
Adoption Trends	Electric Vehicle Adoption	Refreshed light-duty, medium-duty, and heavy-duty electric vehicle (Battery & Plug-In Hybrid) adoption forecast to align with historical actuals and removal of federal tax incentives in September 2025 and enactment of delayed Advanced Clean Cars & Trucks Act.
	Electric Vehicle Supply Equipment (EVSE)	Updated current service territory charging equipment from Alternative Fuels Datacenter to include locational program and non-program PGE enrolled customers. Recalibrated EVSE charging impacts on light-duty vehicles to align with Metro average vehicle miles travelled (VMT) and kWh charging need per mile—including split between home and public/workplace charging behavior.
	Rooftop Solar Adoption	Refreshed historical adoption of rooftop solar installations and recalibrated adoption curve to align with removal of federal incentives for future installations.
	Battery Storage Adoption	Refreshed historical adoption of battery storage installations and recalibrated adoption curve to align with removal of federal incentives for future installations.
	Building Electrification	Refreshed Building Electrification trends based on updated 2024 AMI data and electric heating, cooling, and water heating market saturation data.
Cost-Effectiveness	Avoided Costs & Global Cost Assumptions	Updated assumptions to align with UM 1893 docket for PGE avoided costs. Including updates to generation capacity costs, distribution capacity costs, real discount rate, and inflation rate.

H.2 Aurora

Aurora is a commercially available production cost model developed by Energy Exemplar. This model is used to simulate the interaction of supply, demand, and transmission within a representation of an electrical system. PGE generally uses Aurora in one of two (2) configurations:

WECC model—A model simulating the resources and demand across the Western Electricity Coordinating Council (WECC) region.

PGE Zone Model—A model more narrowly focused on PGE's footprint including PGE resources and demand.

H.2.1 WECC Model

The Western Electricity Coordinating Council (WECC) model is a regional power market model developed and maintained by Wood Mackenzie, a global energy research and consulting firm. For the 2026 CEP/IRP, PGE incorporated the assumptions from Wood Mackenzie's 2024H2 WECC dataset into Aurora to establish the base market environment for simulation and forecasting. This represents an update from the 2023 CEP/IRP, which relied on Wood Mackenzie's 2020H2 assumptions. In addition, PGE updated the wholesale natural gas price forecast using Wood Mackenzie's 2025H1 natural gas price outlook, published in June 2025.

The WECC model incorporates a broad set of regional market assumptions, including:

1. Electric load and resource forecasts by geographic area.
2. Transmission system characteristics, including transfer capabilities, congestion constraints, wheeling costs, and carbon hurdle rates. The model represents both existing transmission infrastructure and planned or under-construction transmission projects.
3. Macroeconomic assumptions, including inflation and environmental compliance costs.
4. Resource operating characteristics, behavioral calibration, and optimization parameters.

PGE uses the WECC model to forecast hourly wholesale electricity prices in the Pacific Northwest. The analysis is conducted as a regional market simulation that applies Wood Mackenzie's assumptions regarding resource additions and retirements, fuel prices, carbon policies, transmission infrastructure, and other market fundamentals over the study horizon of 2027 through 2046. Using a consistent third-party market outlook helps maintain an objective and unbiased representation of regional market conditions and resource behavior. The model seeks to minimize total system production costs across the WECC while satisfying generation, transmission, and operational constraints.

For this analysis, PGE utilized Aurora version 16.0.0001 with the Gurobi optimization solver. Hourly market prices are simulated for the period 2027–2046 across multiple future scenarios reflecting alternative market and policy assumptions.

Within the model, the Pacific Northwest is represented by six (6) geographic zones. The Washington Central zone, which serves as a reasonable proxy for pricing at the Mid-C trading hub, was selected as the primary indicator of regional wholesale electricity prices for PGE's analysis. Simulated hourly prices from the Washington Central zone are subsequently used as inputs to PZM, where they inform the dispatch and valuation of PGE resources.

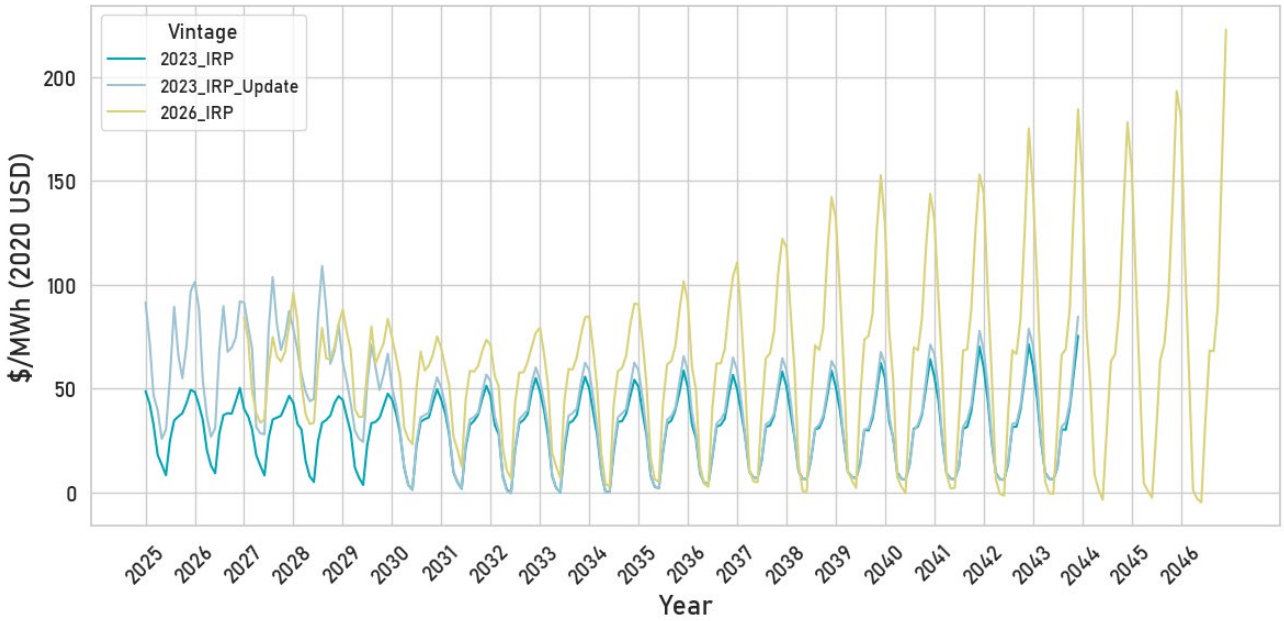
For the 2026 CEP/IRP, PGE incorporates the October 2025 snapshot of the Electric FPC, developed by PGE's Power Cost Forecasting Group using the Lydia Model. The Lydia Model produces an hourly forward price forecast that reflects current market conditions and expectations. Combining the FPC with the long-term WECC market simulation enables PGE to leverage both near-term market signals and long-term regional market fundamentals.

Figure 158 compares the Reference Case hourly electricity price forecast developed for the 2026 CEP/IRP with the corresponding Reference Case forecasts from the 2023 CEP/IRP and the 2023 CEP/IRP Update.

As part of the 2023 CEP/IRP Update, PGE revised its wholesale electricity price forecasting methodology by replacing the near-term WECC market price forecast with PGE's Electric Forward Price Curve (FPC). This enhancement was made to align with Staff recommendations in the UM 1893 proceeding.[230]

For the 2026 CEP/IRP, PGE incorporates the October 2025 snapshot of the Electric FPC, developed by PGE's Power Cost Forecasting Group using the Lydia Model. The Lydia Model produces an hourly forward price forecast that reflects current market conditions and expectations. Combining the FPC with the long-term WECC market simulation enables PGE to leverage both near-term market signals and long-term regional market fundamentals.

Figure 165. Reference Case Prices by Month Across Vintages



The wholesale electricity price forecasts used in the 2026 CEP/IRP are constructed as follows:

- 2027–2029: Prices are based entirely on PGE's Electric Forward Price Curve.
- 2030: Prices reflect an equal-weight blend of the Electric Forward Price Curve and the WECC market simulation forecasts.
- 2031–2046: Prices are based entirely on the WECC market simulation forecasts.

The Reference Case combines PGE's Electric Forward Price Curve (FPC) for the near term with Wood Mackenzie's long-term WECC market outlook. Near-term market prices are based on observed forward market expectations through 2029, while longer-term prices reflect modeled

[230] Oregon Public Utility Commission Staff, Docket UM 1893, Item No. RA2, April 22, 2024, pp. 6–8. Staff recommended use of an Official Forward Price Curve (OFPC) format that incorporates operational forward market prices in the near term and transitions to long-term Aurora-based forecasts. Staff further noted that reliance solely on modeled fundamental forecasts may not adequately reflect market expectations.

regional market fundamentals. The resulting forecast is used throughout the IRP to evaluate resource dispatch, market purchases and sales, and resource economics.

Near-term prices derived from the FPC are generally higher than the corresponding long-term WECC market simulation results. This difference is expected because forward market prices reflect not only participants' expectations regarding future supply-demand fundamentals, but also the value market participants place on hedging price uncertainty. Forward transactions are often executed by load-serving entities, generators, marketers, and other counterparties seeking protection against adverse future market outcomes. As a result, forward prices frequently include risk premiums associated with uncertainty related to weather, fuel prices, system reliability, transmission constraints, and other market conditions. Consequently, forward market prices should not be interpreted solely as forecasts of future spot prices, but rather as risk-adjusted market valuations for future delivery periods.

The seasonal profile of both the FPC and the long-term WECC market outlook reflects the fundamental characteristics of the Pacific Northwest power system. Average prices tend to be lowest during the spring runoff period, typically from April through June, when hydroelectric generation is abundant and regional electricity demand is relatively low. During these conditions, Columbia River basin hydro production is often supplemented by increasing solar generation, resulting in periods where available energy exceeds regional demand. This surplus generation places downward pressure on wholesale electricity prices and can occasionally contribute to very low or negative-priced hours in the Pacific Northwest.

The difference between near-term forward prices and modeled long-term market prices therefore reflects both market participants' pricing of uncertainty in the near term and the expected long-term evolution of regional market fundamentals. As the forecast transitions from the FPC to the WECC market simulation, the influence of short-term risk premiums diminishes, and prices increasingly reflect modeled expectations regarding regional load growth, fuel prices, transmission capability, resource development, and policy assumption

To assess uncertainty in future market conditions, PGE evaluated 37 futures by varying four key risk drivers: electric load growth, carbon price assumptions, natural gas prices, and regional resource development trajectories. These futures capture a broad range of plausible wholesale market outcomes and provide insight into the sensitivity of market prices to changing conditions. In addition, Fast-Start Pricing was incorporated in the base case assumptions for each scenario. Figure 166 shows the spread of annual prices across price futures used in the 2026 CEP/IRP with the average annual prices for the reference case included.

Figure 166. Price Spread Across WECC Price Futures

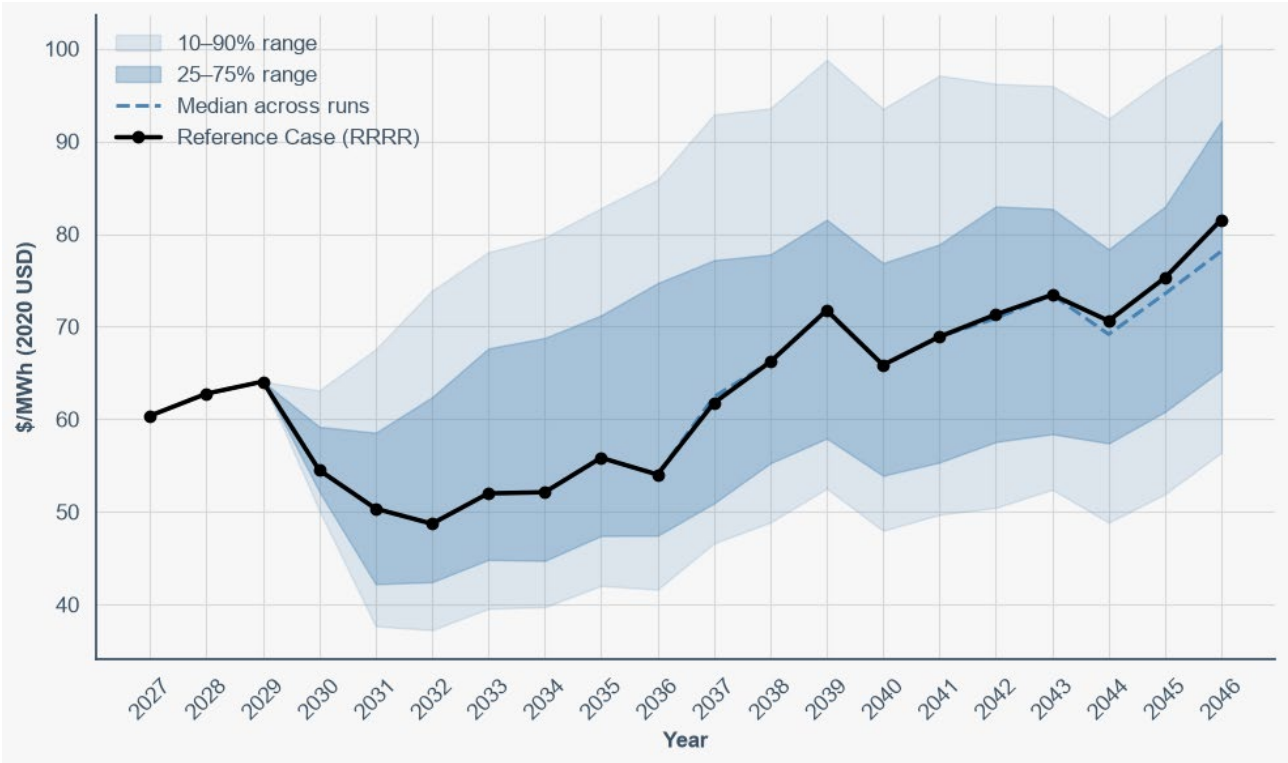
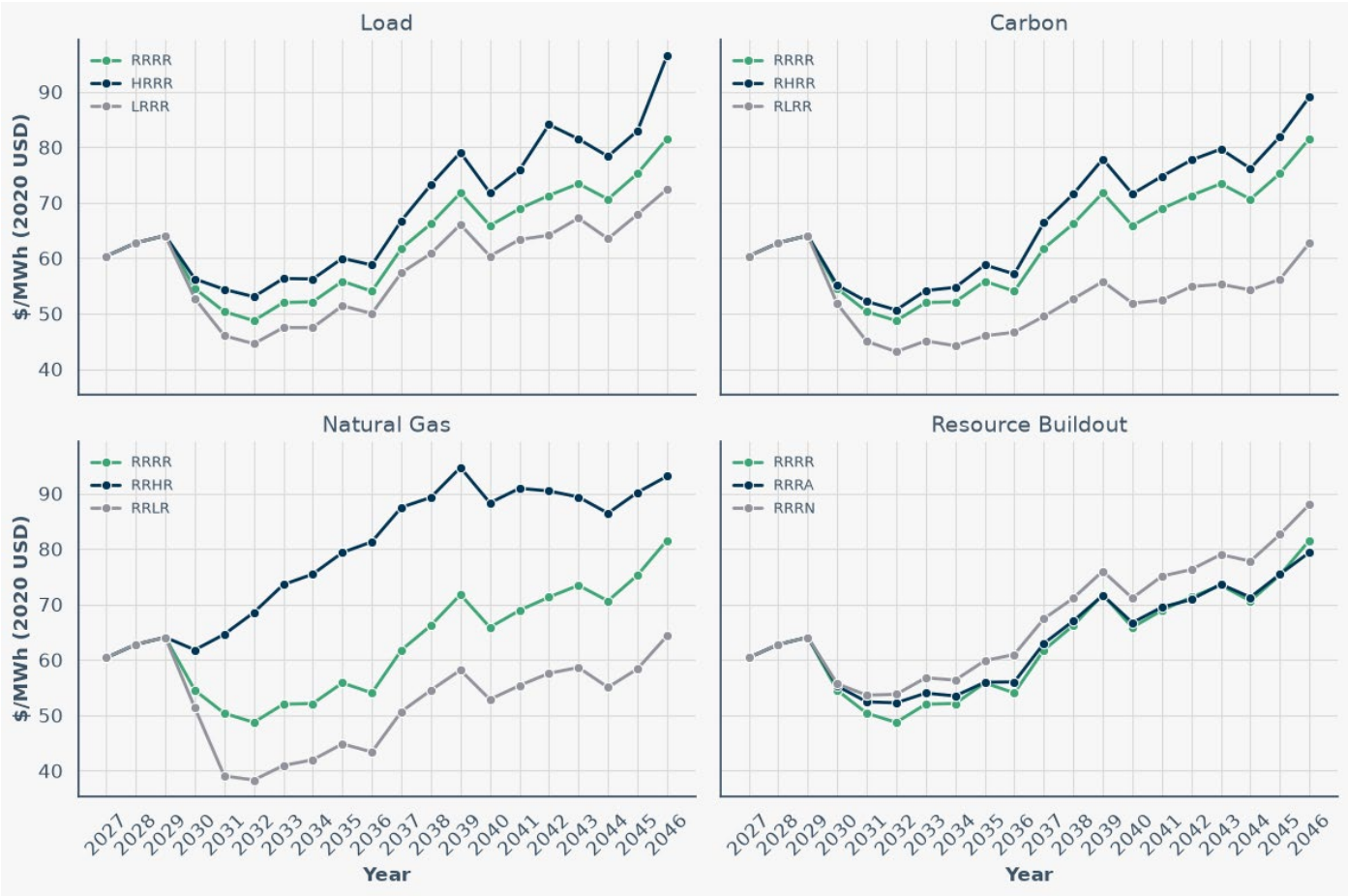


Figure 167 illustrates the impact of the key risk drivers represented in the WECC model on the Reference Case wholesale electricity price forecast. Variations in these drivers produce sustained differences in wholesale market prices over the planning horizon and represent a meaningful range of potential future market conditions.

Figure 167. 2026 Zonal Prices by Month by Key Risk Drivers



H.2.1.1 Electric Load Growth

Since late 2022, load growth forecasts across the electric industry have been revised upward as electrification, domestic manufacturing, and large industrial and datacenter developments have accelerated. At the same time, uncertainty regarding the timing, scale, and persistence of these new loads has increased substantially.

Recognizing both the magnitude of recent load growth and the growing uncertainty surrounding future demand, PGE incorporated load variation as an explicit risk driver in the development of the 2026 CEP/IRP price futures. This reflects PGE's view that load uncertainty is playing an increasingly important role in strategic planning and may have a material impact on future wholesale electricity prices, resource adequacy needs, and infrastructure requirements.

Recent industry assessments support the growing importance of load uncertainty in utility planning. NERC's 2025 Long-Term Reliability Assessment reports that forecasted summer peak demand growth over the next ten (10) years increased from 55 GW in its 2022 assessment to 224 GW in its 2025 assessment, reflecting a dramatic acceleration in expected electricity demand. NERC identifies large industrial loads, datacenters, electrification, and advanced manufacturing as primary drivers of this increase and notes that demand growth projections are rising faster than at any point in the

past two (2) decades. NERC further highlights uncertainty surrounding the pace and location of new large-load development as a key planning challenge for electric utilities and system operators.[231]

Similarly, FERC's 2024 State of the Markets Report identifies rapidly increasing electricity demand from hyperscale datacenters as a major emerging trend affecting U.S. power markets.[232] The U.S. Energy Information Administration (EIA) also reports that national electricity demand growth averaged approximately 1.7% annually from 2020 through 2025, compared to only 0.1% annually during the 2005–2019 period, reflecting a significant shift from the relatively flat demand growth assumptions that characterized much of the past decade.[233]

While the direction of demand growth is generally understood, substantial uncertainty remains regarding the timing, scale, and geographic concentration of new loads. Datacenters, semiconductor manufacturing facilities, and other large industrial developments often have long development timelines and evolving power requirements, making future electricity demand inherently difficult to forecast. As a result, load growth has become one of the most significant sources of uncertainty affecting long-term wholesale electricity prices, resource adequacy requirements, and transmission investment needs.

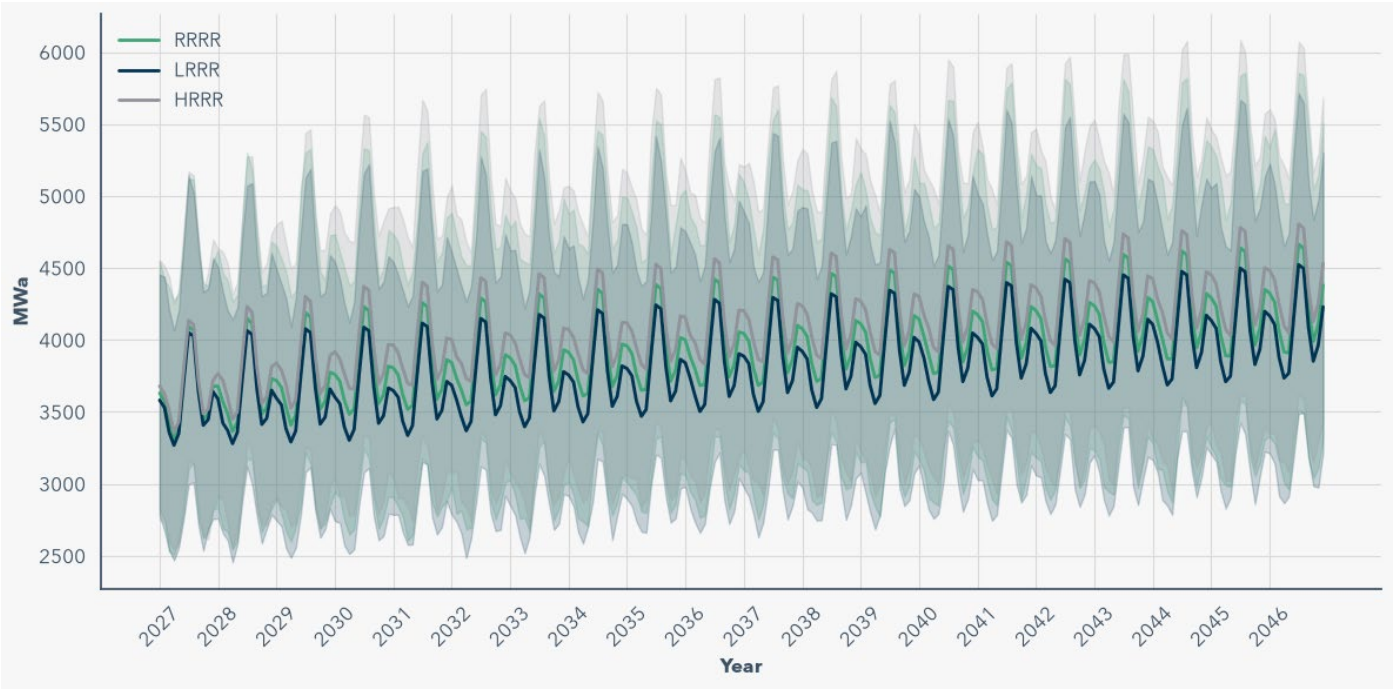
To capture this uncertainty, PGE developed alternative load futures using historical regional load growth patterns. These load futures leave regional supply assumptions unchanged from the reference case forecast. As a result, the modeled futures effectively evaluate the sensitivity of wholesale electricity prices to changing system load under a fixed regional resource portfolio. Historical growth rates were calculated using data from 2008 through 2025 for each WECC region and were used to establish a range of plausible future load trajectories.

1. **Reference Case**: Based on Wood Mackenzie's reference load forecast for each WECC region.
2. **Low Load Case**: For years 2027–2030, PGE adjusts the Reference Case forecast downward to reflect historical average load growth rates observed within each WECC region over the 2008–2025 period. From 2031 onward, the forecast retains the growth rates embedded in Wood Mackenzie's input database, with the adjusted 2030 load level serving as the starting point for future growth.
3. **High Load Case**: For years 2027–2030, PGE adjusts the Reference Case forecast upward by applying a symmetric deviation from the Reference Case equal to the difference between the Low Load and Reference Case forecasts. From 2031 onward, the forecast retains Wood Mackenzie's endogenous growth rates, with the adjusted 2030 load level serving as the starting point for future growth.

These load futures provide a structured framework for evaluating the impact of demand uncertainty on wholesale market outcomes with higher load growth generally placing upward pressure on wholesale electricity prices. See Figure 168 for demand estimates by Load Scenario.

[231] NERC, 2025 Long-Term Reliability Assessment
[232] FERC, State of the Markets Report for 2024
[233] U.S. Energy Information Administration (EIA), Today in Energy, March 2026

Figure 168. Baseline Demand by Month Across Load Futures



H.2.1.2 Carbon Price Assumptions

This section explains how PGE modeled carbon price risk to market prices and unit dispatch simulations. PGE developed carbon adders to represent the cost of carbon policy compliance on power generation. These adders are incorporated into the dispatch costs of CO2-emitting resources based on individual resource fuel type and location. The carbon adders are calculated using the California Energy Commission's (CEC) 2023 carbon allowance price forecast.[234]

The CEC carbon allowance price projections are developed using a combination of observed market conditions and anticipated regulatory outcomes under California's Cap-and-Trade program. The forecast reflects recent increases in allowance prices following the California Air Resources Board (CARB) pre-rulemaking process for revisions to the Cap-and-Trade program. The projection assumes a gradual escalation of allowance prices over time, consistent with assumptions documented in the 2023 Integrated Energy Policy Report (IEPR) preliminary greenhouse gas allowance price projections.

The carbon adders are incorporated into three different carbon futures for the US portion of the WECC. These are depicted in Figure 169.

1. Reference Case: No carbon adders are applied to WECC except for California and Washington, where there is existing carbon pricing legislation. California and Washington carbon adders

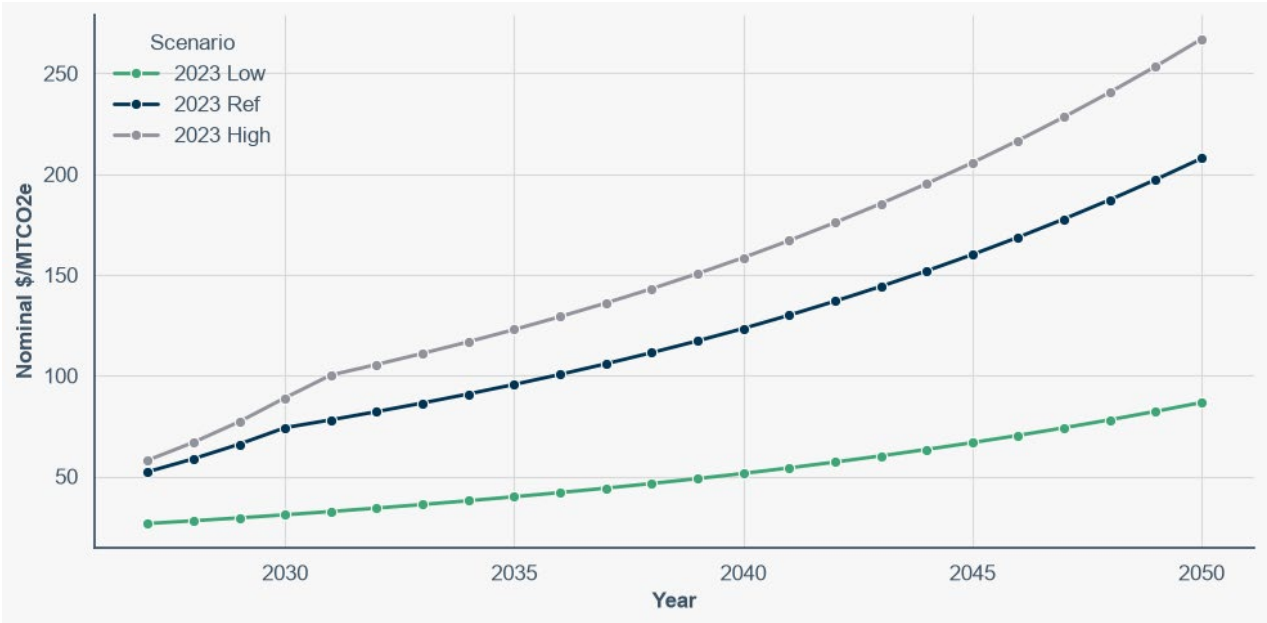
[234] California Energy Commission, 2023 IEPR: Electricity Demand and Electricity Rate Forecast, Cap-and-Trade Allowance Price Forecast section.

apply the 2023 Reference green house gas (GHG) Allowance Price Projections published by the CEC.

2. Low carbon: No carbon adders are applied to WECC except for California and Washington, where there is existing carbon pricing legislation. California and Washington carbon adders apply the 2023 Low GHG Allowance Price Projections published by the CEC.
3. High carbon: No carbon adders are applied to WECC except for California and Washington, where there is existing carbon pricing legislation. California and Washington carbon adders apply the 2023 High GHG Allowance Price Projections published by the CEC.

Across each future, British Columbia and Alberta have a carbon tax adder that reflects Canadian legislation. See Figure 167 for resulting average annual price levels across carbon policy assumptions.

Figure 169. CEC Annual IEPR GHG Allowance Price Projections



H.2.1.3 Natural Gas Prices

PGE developed natural gas price futures for the 2026 CEP/IRP to evaluate the impact of long-term natural gas price uncertainty on wholesale electricity market prices, resource dispatch, and resource economics over the study horizon, years 20272046. The methodology applied is generally consistent with the methodology used in the 2023 CEP/IRP Update, with no material changes to the overall approach.

Consistent with prior IRPs, PGE developed three natural gas price scenarios—Low, Reference, and High—to capture a range of potential future market conditions. For all three scenarios, natural gas prices for 2027 through 2029 are based on PGE's short-term forward natural gas trading curves, which replaced the Wood Mackenzie fundamentals forecast for those years. The three (3) scenarios begin to diverge in 2030 based on differing long-term assumptions regarding market fundamentals and resource availability.

PGE used an interpolation year to transition between the short-term forward curve and the long-term forecast.[235] For the 2026 CEP/IRP, 2030 serves as the interpolation year. The interpolation value was calculated as the average of the annual average natural gas prices for the years immediately preceding and following the interpolation year. Monthly shaping for the interpolation year was based on the Wood Mackenzie natural gas price forecast.

The Reference natural gas price scenario is based on the Wood Mackenzie 2025 H1 Reference Case natural gas price forecast for the period 2030 through 2046. This forecast vintage represented the most recent available long-term forecast at the time PGE performed Aurora modeling for the 2026 CEP/IRP. Figure 170 depicts assumed fuel prices by year for reference case natural gas prices compared to previous IRP filings.

The Low natural gas price scenario reflects an extended period of lower natural gas prices and uses the Wood Mackenzie fundamentals low natural gas price forecast. In instances where values in the Wood Mackenzie Reference forecast fell below the corresponding values in the Low forecast, PGE used the lower of the two values to preserve a consistent representation of downside market conditions.

The High natural gas price scenario was developed using the EIA's 2025 Annual Energy Outlook ("AEO") Low Oil and Gas Supply case.[236] This scenario represents a comparatively constrained natural gas supply outlook and reflects one of the more extreme high-price futures evaluated by the EIA. Annual average prices from the AEO forecast were converted to monthly values using a normalized monthly shape derived from the Wood Mackenzie natural gas price forecast.

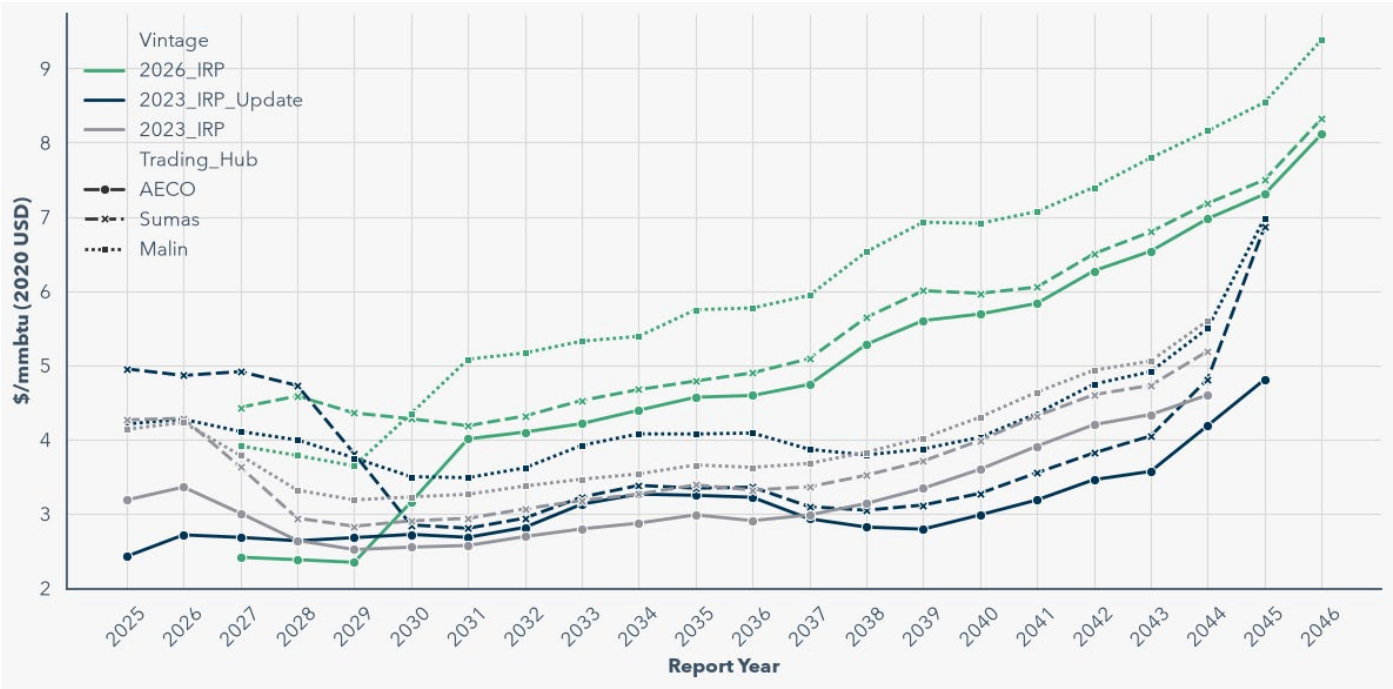
See Figure 167 for resulting average annual price levels across natural gas price assumptions.

Long-term natural gas price expectations increased between the forecasts used in the 2023 CEP/IRP Update and here. Wood Mackenzie attributed the stronger outlook primarily to increased long-term natural gas demand, including continued growth in gas-fired electric generation and expanding liquefied natural gas (LNG) export demand. These market fundamentals were reflected in both the Wood Mackenzie 2024 H2 Base Case Update and the 2025 H1 SPO Base Case forecast.

[235] This approach is consistent with the methodology applied in the 2023 Clean Energy Plan CEP/IRP and 2023 CEP/IRP Update. The value for any given hour is the average of the same hours in the preceding and subsequent years.

[236] https://www.eia.gov/outlooks/archive/aeo25/assumptions/pdf/case_descriptions.pdf

Figure 170. Reference Case (RRRR) Fuel Prices by Year by Vintage



H.2.1.4 Resource Buildout

PGE's choice to model the resource buildout scenario was prompted by major federal policy changes that occurred after implementation of the Wood Mackenzie 2024H2 input database in December 2024. Following enactment of the H.R.1 One Big Beautiful Bill Act ("OBBBA") in 2025 and associated changes to clean energy tax credit eligibility timelines, PGE evaluated how shifts in resource buildout could affect regional price curves.

Federal tax incentives have historically supported renewable resource development, including the Production Tax Credit (PTC) and Investment Tax Credit (ITC). [237, 238] Subsequent policy changes modify statutory requirements governing credit eligibility, including begin-construction timing, safe harbor provisions, and phaseout schedules, reducing the number of projects expected to qualify for these incentives. Broader modeling work by the EIA shows that reduced availability of renewable tax incentives leads to lower renewable capacity additions and higher electricity prices due to increased reliance on alternative generation resources. [239]

The 2024H2 input database, as crafted by Wood Mackenzie, segments wind and solar capacity based on tax credit status using the following naming conventions:

- PTC capacity: Resources actively receiving PTCs (within the 10-year eligibility window or repowered)

[237] Congressional Budget Office (CBO), Business Tax Credits for Wind and Solar Power (April 2025)
[238] Internal Revenue Service (IRS), Clean Energy Tax Incentives for Businesses (Publication 5886) (March 2024).
[239] U.S. Energy Information Administration (EIA), Annual Energy Outlook 2022: Issues in Focus—Tax Credit Cases (March 2022).

- Non-PTC capacity: Includes expired PTC resources, ITC-based projects, and unsubsidized capacity

To reflect changes in federal policy, PGE removes a subset of future renewable additions during 2028-2033. For wind and solar resources classified as PTC-supported, PGE maintains 2028 levels of resource additions through 2033. After 2033, PGE resumes resource additions at the same rate of growth embedded in Wood Mackenzie's original database. These years align with the period in which extended PTC eligibility under the IRA would have supported additional development but where subsequent policy changes reduce incentive availability.

This adjustment preserves near-term additions while reducing future PTC-dependent capacity growth. The approach is consistent with methodological adjustments incorporated by Wood Mackenzie in the subsequent 2025 H1 SPO update.

The intention of this study is not to alter the total amount of energy supplied by zone relative to Wood Mackenzie's baseline assumptions. Instead, the analysis focuses on how changes in the technology mix used to serve that energy effect regional price forecasts.

To isolate this effect, two (2) replacement scenarios are constructed to substitute for the removed wind and solar capacity:

- A natural gas-based replacement, and
- A nuclear and geothermal-based replacement.

All adjustments are energy-neutral at the zonal level. For each zone, the average megawatt (MWa) generation from the removed resources is calculated, and an equivalent amount of energy is added back using the replacement technologies. This ensures that changes in electricity price outcomes are driven by differences in resource characteristics rather than changes in energy available to serve load.

Figure 171 shows the difference from reference case (RRRR) in model output (MWa) and nameplate capacity by resource type, including total wind and solar generation removed under the buildout scenario and generation added from the replacement natural gas (RRRN) and alternative technology resources (RRRA). The amount of nameplate capacity of wind and solar is much greater than the replacement technologies due to the lower capacity factors.

Figure 171. WECC-wide Effects of Future Resource Buildout Uncertainty – Replacement of Reference PTC/ ITC eligible Solar and Wind (RRRR) by Natural Gas (RRRN) and Alternative Non-Emitting (RRRA) Resources

The resulting price differences across the resource buildout scenarios, as shown in are primarily driven by differences in variable costs and flexibility. The variable cost of natural gas is higher than that of wind, solar, nuclear, and geothermal. While nuclear fuel costs are also increasing at a rate proportional to natural gas over the duration of the study, geothermal has no variable cost of operation.

Technology type influences the shape of intraday prices through differences in flexibility. Compared with wind and solar, replacement technologies are more flexible because these technologies can supply energy during high-demand periods, reducing peak prices while also displacing zero (0)- or negative-priced renewable generation and increasing midday prices. As renewable penetration and thermal retirements increase over the duration of the study, the impact of more flexible resources become more pronounced, with the net impact varying by season depending on the balance between peak price reductions and midday price increases.

Given the higher variable cost of natural gas, natural gas prices are higher than reference case across all years of the study, starting in 2028. Under the alternative technology scenarios, prices are higher than reference case in early years of the study and then lower in later years reflecting higher

variable cost of nuclear fuel in early years but then offset by flexibility wherein prices are lower during non-solar hours.

H.2.1.5 Fast-Start Pricing

Energy market prices are traditionally determined by the marginal operating cost of the highest-cost resource dispatched to serve load. However, during periods of tight system conditions, marginal energy prices alone may not fully reflect the cost of committing and operating flexible thermal resources. In particular, fast-start generating units often incur significant start-up and commitment costs that are not captured in conventional marginal energy pricing. As a result, market prices may understate the true cost of serving load and fail to provide efficient price signals during periods when system flexibility is most valuable.

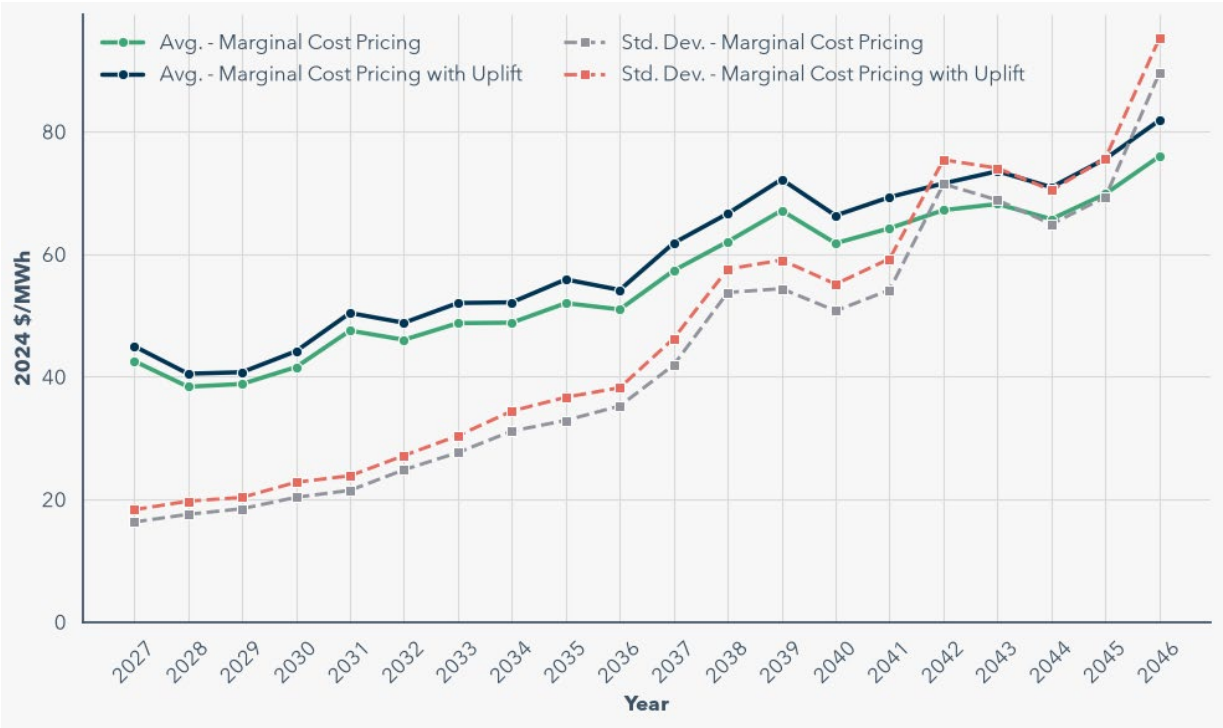
To address this issue, PGE incorporates fast-start pricing into all wholesale electricity price futures. Within Aurora, PGE activates the Uplift Logic option, which allocates thermal resource start-up costs across the hours during which the unit is online and incorporates those costs into simulated market prices.[240] This approach allows prices to better reflect the full cost of serving load, including the costs associated with committing flexible generation resources.

The treatment of start-up costs in market prices is consistent with ongoing price formation enhancements across organized electricity markets. FERC has recognized that conventional locational marginal prices may not fully compensate fast-start resources for their commitment costs, resulting in prices that do not accurately reflect the marginal cost of serving load. As part of broader price formation reforms, FERC has encouraged regional market operators to incorporate fast-start resource costs into market prices to improve economic efficiency and investment signals.[241] Similarly, CAISO's Price Formation Enhancements initiative is currently developing fast-start pricing mechanisms within the Extended Day-Ahead Market (EDAM) that more fully reflect commitment and start-up costs in market-clearing prices and reduce reliance on out-of-market uplift payments.[242] PGE announced in March 2024 the company's intent to join CAISO's EDAM. This change is intended to better represent the market conditions PGE will face within EDAM.

PGE applies fast-start pricing only during on-peak hours in the Pacific Northwest. This treatment reflects the observation that thermal unit commitments and associated start-up costs are more likely to influence market outcomes during periods of elevated demand and tighter operating conditions. During off-peak hours, system conditions are generally less constrained, thermal commitment decisions are less frequently marginal, and start-up costs have a smaller impact on market-clearing prices. These results are demonstrated in Figure 172. Limiting fast-start pricing to on-peak periods therefore better aligns the modeled price adder with the hours in which commitment costs are most likely to be reflected in actual market outcomes.

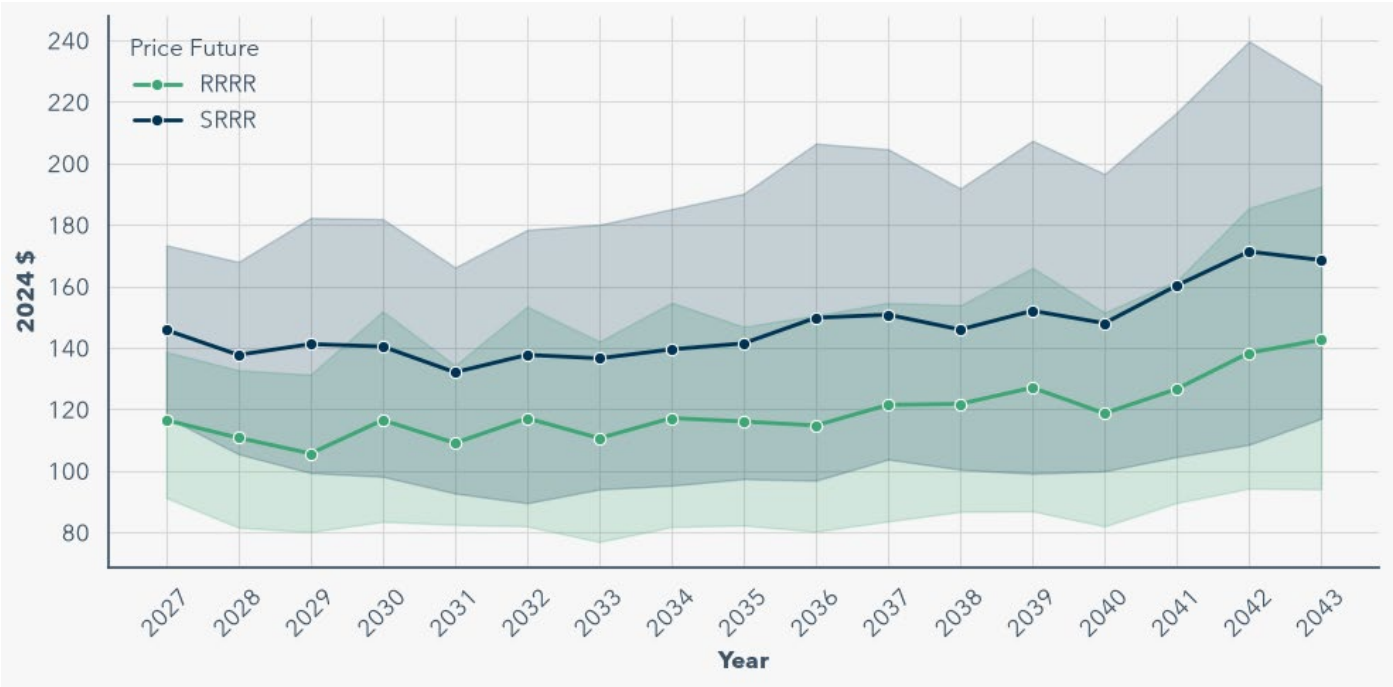
[240] This methodology is consistent with the construction of the uplift price future employed in the 2023 CEP/IRP. However, in the 2026 CEP/IRP, rather than create a specific price future to reflect fast-start pricing, the logic is applied to all price futures.
[241] FERC Price Formation Reform, FERC, FERC to Investigate Pricing of Fast-Start Resources by Three Grid Operators (20d17).
[242] CAISO Price Formation Enhancements, CAISO, Price Formation Enhancements stakeholder initiative and Fast Start Pricing working group materials (2024–2025).

Figure 172. Average Annual Prices and Standard Deviations Before and After Applying Uplift Pricing



With the inclusion of fast-start pricing, the increase in the price volatility provides greater opportunity for storage resources to price arbitrage across the day. Looking at data from the WECC prices from the 2023 CEP/IRP, the energy value of a 4-hour battery under the SRRR (fast-start price future) and RRRR (reference case price future) scenarios are compared. Across years 2027-2043, a 4-hour battery is forecast to generate an additional $330,000 per year, or 23.2% more, in revenue under the SRRR scenario compared to RRRR. This difference is depicted in Figure 173.

Figure 173. Average Annual Energy Revenue for 4-hour battery With (SRRR) and Without (RRRR) Fast Start Pricing



H.2.2 PGE Zone Model

The Aurora PGE Zone Model (PZM) is PGE's production cost model used to simulate the economic dispatch of existing generating resources, contracts, market transactions, and candidate resources under a range of future market conditions. The PZM is used to estimate the energy value and capacity factors of candidate proxy resources across the 37 wholesale electricity price futures simulated in the WECC production cost model. It also estimates the variable operating costs, energy value, baseline resource costs, and baseline net contract costs for PGE's existing resource portfolio, including the dispatch of thermal generation used to serve both retail load and wholesale market transactions. In addition, for this planning cycle, the PZM is also used to estimate the hourly GHG emissions associated with serving PGE retail load for the resource portfolios developed in ROSE-E.

The PZM is built using Aurora topology and represents individual generating resources, including thermal generation, storage, and variable energy resources (VERs), as well as separate market and PGE retail load zones. Model inputs include the operating characteristics and variable costs of existing PGE resources, contracts, and candidate resources, generally consistent with the assumptions used in the 2026 Annual Update Tariff (AUT) filed on November 17, 2025. Fuel prices and carbon dispatch adders are aligned with those used in the WECC model, with the exception of Colstrip, where more detailed plant-specific fuel assumptions are applied. Hourly wholesale electricity prices for the Pacific Northwest are obtained directly from the WECC production cost model.

The PZM is applied in three (3) distinct configurations, each designed to support a specific analytical need: (1) proxy resource valuation, (2) portfolio cost and operational analysis, and (3) emissions estimation. These analytical needs are summarized and described by module in Table 76. Although all three applications utilize the same underlying model topology and resource representation, they employ different dispatch logic and constraints to produce the outputs required for resource valuation, portfolio optimization, and emissions assessment.

Table 76. Summary of PZM Modules

Module	Dispatch Logic	Constraint	Key Outputs
Proxy Resource	Market price-taker	None	Energy values, capacity factors
Portfolio	Meets retail load	Applied with and without HB 2021 strictly enforced	Production cost, dispatch and market purchases
Emissions	Meets retail load	HB 2021 relaxed subject to reliability	Emissions metrics

H.2.2.1 Proxy Resource Module

The Proxy Resource Module uses a price-taker methodology to estimate the potential energy value of candidate resources across a range of future market conditions. Under this approach, PZM dispatches resources against exogenous wholesale electricity prices, implicitly treating PGE as a price taker within the Western Interconnection. Generating resources produce energy whenever their variable operating costs are lower than prevailing market prices.

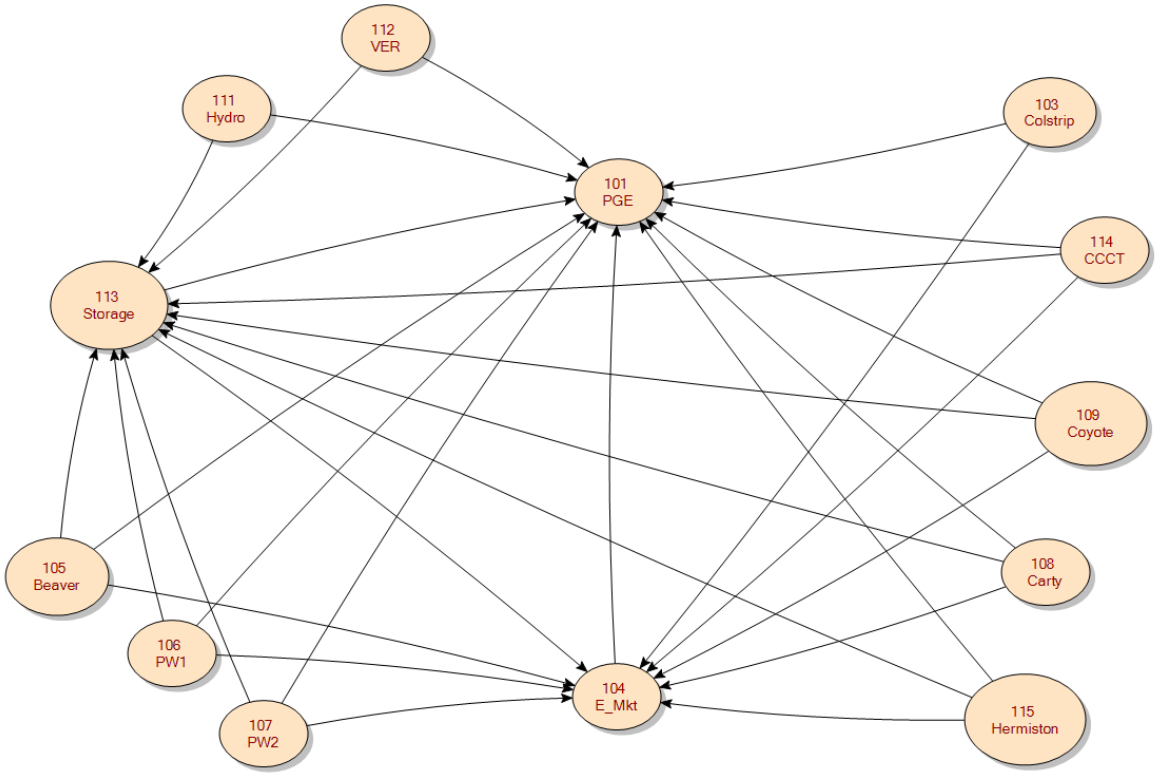
This methodology is used to estimate the energy value and capacity factors of candidate proxy resources across the 37 wholesale electricity price futures simulated in the WECC production cost model. Because the objective of this module is resource valuation, dispatch is driven solely by market economics and does not reflect the load-serving obligations represented in the portfolio analysis. Primary outputs from the Proxy Resource Module include proxy resource energy values and monthly capacity factors for candidate resources.

H.2.2.2 Portfolio Module

The Portfolio Module is used to estimate the operating costs and resource utilization associated with serving PGE retail load. Unlike the price-taker methodology, this configuration explicitly distinguishes between generation serving PGE retail customers and generation sold into the wholesale market.

To support implementation of HB 2021 and improve the hourly representation of retail load service, the 2026 CEP/IRP modified the dispatch logic used within the PZM. Rather than dispatching resources solely against wholesale market prices, the model dispatches the PGE system to meet retail load while retaining the ability to purchase energy from the wholesale market when economic. Links are established between all PGE generation resources and the retail load zone, as well as between generating resources and the wholesale market, allowing Aurora to optimize the allocation of generation between retail load obligations and wholesale transactions. This is shown in Figure 174.

Figure 174. Mapping of PZM Topology



While the Portfolio Module uses a different dispatch framework than the Proxy Resource Module, wholesale market purchases and sales are still valued using the same exogenous wholesale electricity prices from the WECC production cost model described above in Appendix Section H.2.1.1. Consequently, market transaction values are consistent with the simulated market prices for each price future rather than any marginal prices produced within the Portfolio Module dispatch. The primary outputs of the Portfolio Module include variable operating costs and energy values for existing resources, baseline resource costs, baseline net contract costs, annual variable production costs, thermal and non-thermal resource dispatch, and net wholesale market purchases.

For portfolio cost analysis in GHG glidepath scenarios, annual HB 2021 emissions constraints are strictly enforced, consistent with the assumptions described in Appendix Section I.2. This represents a change from the previous CEP/IRP cycle, replacing PGE's use of the intermediary GHG (iGHG) model with direct representation of emissions constraints in the economic dispatch model. The resulting production cost estimates are used as baseline inputs for portfolio development within ROSE-E.

For reliability-only (RO) scenarios, annual HB 2021 emissions constraints are removed, allowing thermal generation emissions to exceed HB 2021 limits when necessary to meet load in the absence of sufficient non-emitting resources. The resulting production cost estimates are likewise used as baseline inputs for portfolio development within ROSE-E.

For portfolios based on the Continued Progress scenario assumptions, the baseline production cost input is calculated as the average of the GHG glidepath and RO production cost estimates.

H.2.2.3 Emissions Module

The Emissions Module utilizes the same retail load-serving dispatch framework as the Portfolio Module but is designed to evaluate the emissions impacts of alternative resource portfolios. In this configuration, the model dispatches resources to serve retail load using the same underlying topology and operational assumptions described above. The module calculates and reports emissions associated with serving PGE retail load across different resource portfolios.

For portfolios based on the GHG Glidepath and Continued Progress scenarios, the annual HB 2021 emissions constraint is enforced during dispatch. This configuration enables evaluation of portfolio emissions outcomes under statutory emissions compliance requirements and reflects the emissions assumptions underlying these scenarios. For Reliability Only (RO) scenarios, the HB 2021 emissions constraint is not imposed, allowing resources to be dispatched based solely on reliability and economic considerations. The Emissions Module nevertheless tracks and reports the resulting emissions, providing insight into the emissions implications of maintaining reliability under conditions where thermal generation may be required to serve load.

This approach provides visibility into the relationship between resource portfolio composition, reliability needs, and emissions outcomes, and enables comparison of portfolio performance relative to statutory emissions reduction targets.

H.2.2.4 Emissions Accounting

PGE will provide forecasted GHG emissions information to the Oregon Department of Environmental Quality (ODEQ) as part of the CEP review process. ODEQ is responsible for verifying that projected emissions reductions and the associated emissions accounting methodology comply with Oregon's greenhouse gas reporting requirements and the Clean Energy Targets established under House Bill 2021. Specifically, ODEQ reviews the emission factors and calculation methodology used in utility forecasts to ensure consistency with the agency's greenhouse gas reporting protocols.[243]

Unless otherwise noted, the emission factors applied to each GHG-emitting generating resource in this analysis are consistent with those assigned by ODEQ for CEP projections. This analysis uses the Assigned Emission Factors for Use in 2025 CEP dataset, Version 6, last updated March 14, 2025, as summarized in Table 77 below. PGE's analysis of alternative emission factors for unspecified Market purchases is discussed in Appendix Section I.5 These alternatives to the ODEQ-assigned Market emission factor incorporate information about potential future regional resource mixes and illustrate the extent to which the average annual Market emission factor can be influenced by the assumed resource composition. Additional details regarding the Alternative Market Scenario and HB 2021 compliance assumptions are provided in Appendix Section I.2.

[243] Oregon Department of Environmental Quality. Oregon Clean Energy Targets. State of Oregon. https://www.oregon.gov/deq/ghgp/pages/clean-energy-targets.aspx

Table 77. Summary of Oregon DEQ GHG Emission Factors

Resource	MT CO2e/MWh
Beaver	0.538
Carty	0.389
Colstrip	1.003
Coyote Springs 1	0.380
Hermiston	0.388
Port Westward 1	0.376
Port Westward 2	0.506
Market	0.428

H.2.2.5 Portfolio Emissions Evaluation

The Emissions Module is used to estimate forecasted greenhouse gas (GHG) emissions associated with each candidate resource portfolio developed in the ROSE-E portfolio analysis tool. Annual emissions are reported in million metric tons of carbon dioxide equivalent (MMTCO2e) and are used to evaluate portfolio compliance with the emissions reduction requirements established under House Bill (HB) 2021.

ROSE-E develops candidate portfolios using annual and monthly planning constructs that are well-suited for identifying least-cost, least-risk resource combinations and evaluating long-term planning outcomes. However, electric systems are ultimately tested one hour at a time. Periods of low renewable output, changing load conditions, and reliability needs can require operating decisions that are not fully visible within a monthly planning framework. As a result, emissions outcomes estimated within ROSE-E may differ from those observed when the same portfolio is subjected to hourly operational simulation.

To account for these operational realities, each candidate portfolio is evaluated in the Aurora PGE Zone Model (PZM) Emissions Module. Using the portfolio developed in ROSE-E as a starting point, the PZM performs an hourly dispatch simulation. The model evaluates the chronological operation of generation resources, storage facilities, contracts, and market transactions under the operational assumptions described above. In doing so, it captures the periods when reliability requirements necessitate dispatch decisions that may not be evident in higher-level planning analyses.

Hourly GHG emissions are calculated for each emitting resource using the Oregon Department of Environmental Quality (ODEQ) emission factors shown in Table 77. The emissions associated with each hour of operation are then aggregated to develop annual system emissions forecasts. These annual emissions forecasts are compared against the applicable HB 2021 GHG emissions glidepath, including the requirement to achieve emissions of no more than 1.62 MMTCO2e by 2030.

For portfolios intended to satisfy HB 2021 emissions requirements, PGE applies an iterative evaluation process to ensure compliance under hourly operational conditions. Following the initial Emissions Module simulation, forecasted annual emissions are compared against the applicable glidepath target. If forecasted emissions exceed the target, additional non-emitting resources are

added to the portfolio through a portfolio adjustment. See Figure 175 for comparison of the HB 2021 Preferred Portfolio with and without the portfolio adjustment.

Figure 175. Forecasted System Emissions of HB 2021 Preferred Portfolio with Hybrid Portfolio Adjustment

Portfolio adjustments evaluate several resource options, including emerging technologies, hydro resources, and the Southeast Washington (SEWA) hybrid proxy, a resource composed of wind, solar, and battery storage. The selection of resources for the portfolio adjustment is based on minimizing incremental portfolio cost while reducing emissions. The adjustment process recognizes that some emissions impacts only emerge when portfolio performance is evaluated at hourly operational granularity, requiring targeted resource additions beyond those identified in the initial portfolio optimization.

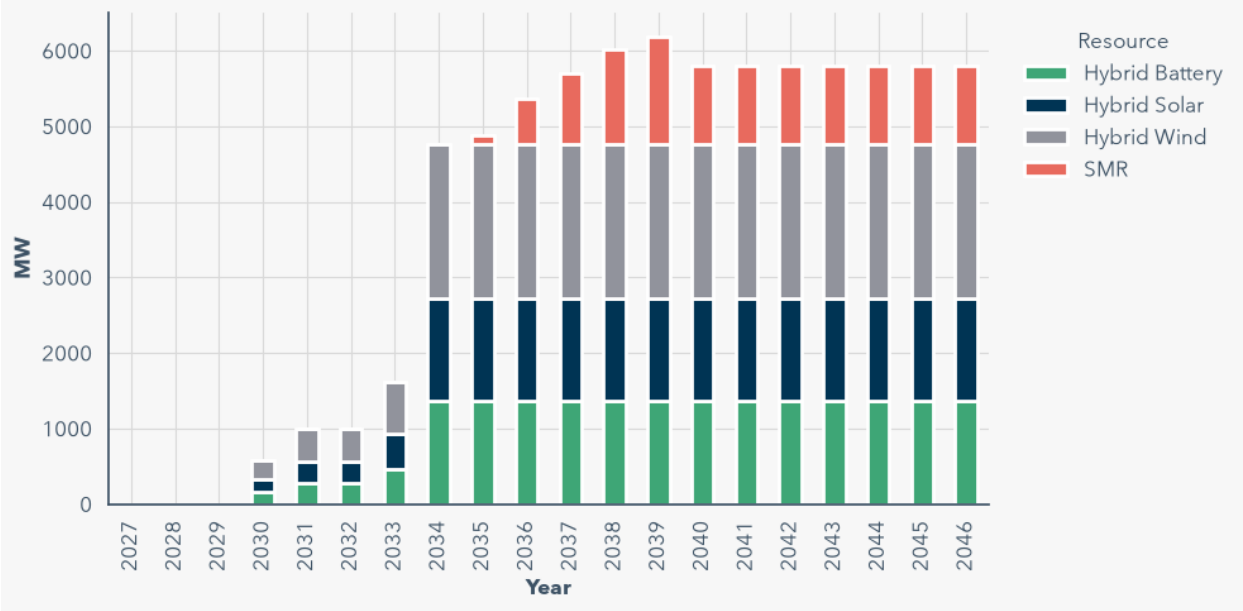
Following the portfolio adjustment, the adjusted portfolio is re-evaluated in the PZM Emissions Module. The model redispatches the PZM and calculates the resulting system emissions. Annual emissions are again compared against the applicable GHG glidepath. Additional incremental resources are added as necessary, and the portfolio is repeatedly re-simulated until forecasted annual emissions are projected to satisfy the applicable HB 2021 compliance requirements, including achievement of the 2030 target of 1.62 MMTCO2e.

Through this evaluation, PGE determined that the SEWA hybrid resource represents the most cost-effective option for addressing incremental emissions needs through 2034. Beginning in 2035, emerging technology becomes the lowest-cost resource for reducing emissions and maintaining compliance.

The portfolio adjustment serves as a final refinement step, addressing emissions impacts revealed through detailed hourly operational modeling and ensuring compliance is achieved using the lowest-cost combination of incremental resources. The quantity of incremental resource additions

that are included in the portfolio adjustment for the HB 2021 Preferred Portfolio are shown in Figure 176.

Figure 176. Incremental Resource Additions for Portfolio Adjustment for HB 2021 Preferred Portfolio



H.2.2.6 Non-Firm Transmission Representation in PGE Zone Model

The results of the Transmission Constraints IRP Analysis as outlined in Appendix Section L.5 are incorporated into the PGE Zone Model (PZM) to represent the operational risks associated with non-firm transmission service. The 12×24 transmission constraint heatmap developed from the GridView Production Cost Model provides an hourly representation of the probability that one or more BPA transmission paths or flowgates are constrained under 2035 system conditions.

The heatmap is applied to all resources within the PZM that depend on non-firm transmission service for delivery into the PGE load area. These resources include both existing and candidate resources whose energy output is assumed to utilize non-firm transmission products. The purpose of this adjustment is to reflect the increased risk of transmission curtailment during periods when regional transmission facilities are expected to experience elevated utilization.

For each month and hour of day, the heatmap value represents the percentage of historical simulation hours in which at least one of the analyzed transmission paths was constrained. This percentage is interpreted as a transmission availability adjustment and is applied to the hourly energy profile of affected non-firm resources. As a result, resource energy deliveries are reduced during periods with elevated transmission congestion risk, while periods with low congestion risk experience little or no adjustment.

Within the Proxy Resource Module, the transmission constraint adjustment is applied directly to the hourly generation profile of non-firm candidate resources. The adjusted hourly generation profile is then used to calculate annual energy production, capacity factors, and energy value metrics. By reducing resource output during hours with elevated transmission congestion risk, the

methodology captures the impact that non-firm transmission curtailments may have on the economic value of candidate resources. Consequently, proxy resource energy values reflect not only the underlying market price signals represented in the WECC production cost model, but also the expected availability of transmission required to deliver energy to market.

Within the Portfolio Module, the transmission constraint adjustment affects the quantity of energy available from non-firm resources to serve PGE retail load. Because the Portfolio Module explicitly balances generation, market transactions, and retail load obligations, any reduction in available non-firm resource energy directly affects the load-resource balance. When transmission constraints reduce the effective energy contribution of non-firm resources, the model must either increase dispatch from other available resources or procure additional energy from the wholesale market to maintain reliability and satisfy retail load requirements. As a result, transmission congestion can increase production costs, alter resource dispatch patterns, and affect net wholesale market purchase requirements.

The same transmission constraint adjustment methodology is applied within the Emissions Module. Reductions in non-firm resource deliveries change the mix of resources available to serve retail load and may require increased dispatch of alternative generating resources or increased market purchases. Because emissions are calculated based on the actual dispatch required to meet load, reductions in resource availability arising from non-firm transmission can influence portfolio-level emissions outcomes. Incorporating the transmission constraint adjustment therefore ensures that emissions estimates reflect both resource operating characteristics and the practical limitations associated with future transmission availability.

By consistently applying the transmission constraint heatmap across all PZM configurations, the 2026 IRP captures the improved representation of the economic, reliability, and emissions implications of non-firm transmission risk, providing a more comprehensive representation of resource performance under expected 2035 transmission system conditions.

H.2.2.7 PGE Zone Model and Extended Day Ahead Market

From a planning perspective, the WECC model determines electricity prices across interconnected geographic zones while accounting for transmission constraints, which can create congestion and result in different market prices between regions. The PGE Zonal Model (PZM) uses these WECC-derived prices to represent wholesale market opportunities but does not model system transmission constraints on market transactions. Instead, the PZM assumes market purchases and sales are available without explicit limits, allowing the model to optimize PGE's resource portfolio based on regional market prices rather than available transmission capacity. Non-firm transmission assumptions and transmission limits are applied at the individual or co-located resource level, where appropriate, to represent resource-specific delivery constraints.

EDAM economically dispatches resources across participating balancing authorities while respecting the physical transmission network, transmission rights, and reliability requirements. The market optimization increases access to least-cost generation and can reduce congestion costs, but transactions remain limited by available transmission capacity and other operational constraints. Consequently, EDAM does not eliminate transmission constraints or create unlimited access to regional energy markets.

Because the PZM assumes unconstrained market transactions at WECC-derived prices, it should not be interpreted as a simulation of EDAM operations or as an estimate of EDAM benefits. Instead, the modeling approach represents a simplified planning abstraction that captures the economic value of regional market access while relying on the WECC model to establish market prices that already reflect regional supply-demand conditions and transmission congestion. As a result, the PZM may capture some of the economic effects associated with increased market participation, but it does not explicitly model the operational efficiencies, transmission utilization, or production cost savings that would result from EDAM implementation.

H.3 LUCAS—Levelized Fixed-Cost Revenue Requirement Tool

The Levelized Utility Cost Aggregator System (LUCAS) is an Excel model used to calculate revenue requirements for the fixed costs of PGE-owned and new proxy supply-side resources.

> *Revenue requirement: The change in utility rates (utility revenue) to recover the operating costs, depreciation, taxes, and allowed return on an investment.*

Significant inputs to LUCAS include:

1. Financial assumptions:
    a. PGE's cost of capital (cost of equity, dept, and capital structure),
    b. long-term inflation expectations,
    c. tax rates (federal, state, and property),
    d. federal tax credits, and
    e. tax depreciation rates.
    f. PGE-owned resources:
    g. PGE's book and tax depreciation,
    h. economic life,
    i. deferred tax,
    j. fixed O&M,
    k. scheduled capital additions, and
    l. fixed gas transportation costs.
2. Proxy supply-side resources:
    a. Overnight capital costs,
    b. fixed operations & maintenance (O&M),
    c. economic life,
    d. decommissioning costs, and

e. wheeling.

Information on the proxy supply-side resources is provided in Appendix Section G.5.

For a given resource, the LUCAS model is used to calculate the total fixed revenue requirement for each year the resource is expected to operate. The revenue requirement uses PGE's capital structure.

At a high level, the steps to compute the annual fixed revenue requirement for a resource include:

1. Begin with an overnight capital cost estimate—this is the expected cost to bring a resource online without consideration for financing and other costs incurred during construction. The assumed overnight capital cost may change across different resource cost scenarios.
2. Apply a construction schedule and estimate the financing and other costs incurred during construction—these costs may include the carrying cost as the capital investment is deployed (allowance for funds used during construction or AFUDC) as well as property taxes.
3. After the resource is placed in service, the revenue requirement model assumes that PGE will earn its regulated rate of return on the investment (ratebase).
4. Over the resource's useful life, a portion of the original investment is recovered annually in the revenue requirement—this represents depreciation of the asset. Depreciation rates may differ for book and tax purposes.
5. Property and income taxes are recovered annually.
6. In addition to investment-related items, the fixed revenue requirement includes recovery of fixed-cost expenditures to operate the resource (fixed operational expenditures, fixed operations and maintenance, or fixed O&M). The assumed fixed operational expenditures may change across different resource cost scenarios.

The return on and return of investment and recovery of fixed operating expenditures are summed in each year across the resource's expected useful life and represent the fixed revenue requirement. This is revenue from the utility perspective and cost from the customer's point of view. The net present value of the annual, nominal, revenue requirement is calculated.

> *Net present value – The sum of costs and benefits (from a project or investment) occurring across multiple periods discounted to a common point in time.*

From the net present value, discount rate, and resource useful life, one of the key resource metrics is calculated, the levelized value.

> *Levelized value – The distribution of a present value lump sum in equal periodic payments over a given term (annuitization). The payments can be equal on a "real" basis (before the effects of inflation – "real levelized") or on a "nominal" basis (including expected inflation – "nominal levelized").*

The steps are repeated for each resource option by commercial operation date (COD) and cost scenario. Cost scenarios include Low, Reference, and High.

From LUCAS, the real-levelized fixed costs are passed to ROSE-E for evaluation of proxy resource economics in portfolio construction and determination of the fixed component of portfolio costs. The real-levelized fixed costs for ROSE-E are normalized by the nameplate capacity (or interconnection for co-located resources) investment of each resource and represent the annual revenue requirement of that resource in terms of dollars per kilowatt (kW) investment ($/kW-year).

H.3.1 Long-Term Financial Assumptions

As required by Guideline 1a of Order No. 07-002, PGE's estimated after-tax marginal weighted average cost of capital of 6.91% serves as a proxy for the long-term cost of capital to discount future costs and benefits.

> *Discount rate – The concept of time value of money establishes a general preference for amounts received sooner rather than later in time. The discount rate is a value that creates equivalence between payments received in different time periods; for example, by "discounting" future values to produce a present value. The discount rate used in PGE's financial modeling is the weighted after-tax cost of capital (discount rate) listed above.*

PGE's long-term cost of capital estimate is based on information available as of Q3 2025. Table 78 contains a summary of relevant financial assumptions.

Table 78. 2026 IRP Long-term Financial Assumptions

Component	Percent
Composite Income Tax Rate	27.5%
Incremental Cost of Long-Term Debt	6.2%
Long-Term Debt Share of Capital Structure	50.0%
Common Equity Return	9.3%
Common Equity Share of Capital Structure	50.0%
Weighted Cost of Capital	7.8%
Weighted After-Tax Discount Rate	6.9%
Long-Term General Inflation	2.0%

H.4 GridPath

GridPath is an open-source production cost simulation model designed and maintained by Sylvan Analytics. This model was used in the 2026 CEP/IRP Flexibility Study to assess flexibility adequacy of PGE's system and estimate the flexibility value and integration costs for various resource options. For details on the model reference Appendix Q.

H.5 Sequoia

This section provides an overview of the Sequoia model and focuses on changes made to Sequoia and its inputs as part of the 2026 CEP/IRP. Sequoia inputs are shown in Table 79. Sequoia is PGE's proprietary resource adequacy (RA) model used for reliability assessment and capacity accreditation. These analyses define the seasonal capacity needs of PGE's system and the effective load carrying capabilities (ELCC) of proxy resources used in portfolio expansion. For a review of Capacity Need as estimated in Sequoia for the 2026 CEP/IRP see Section 6.6.1.2. For a review of resource Effective Load Carrying Capabilities as estimated in Sequoia for the 2026 CEP/IRP see Appendix Section G.6. For more detailed information about the Sequoia model, see Appendix K of the 2019 IRP Update.[244]

H.5.1 Summary of Sequoia Inputs

Table 79. Sequoia Key Input Summary

Category	Update	Description & Source
Supply	Virtual Power Plant (VPP) Capacities	Forecasts of flexible load (DR) and Dispatchable Stand-by Generation (DSG) capacity removed from PGE's base portfolio. Year ending 2025 quantities of these VPP resources are assumed to be constant during the planning horizon and incremental additions are modeled in ROSE-E
	Hydro Shapes	Weekly energy limits for major projects and contracts updated to 2024 BPA Load & Resources Study (Whitebook). Minimum and maximum hourly capacity limits are updated to PGE 2024 AUT.[245]
	Intertie Transfers	Revised emergency intertie capacity based on PGE's historical reliability related operations.
	Qualified Facilities (QF) Inputs	Refreshed to fall 2025 PGE QF projects, including 75% realization of contracts in negotiation and 75% renewal of expiring contracts.
	'23 Request for Proposal (RFP) Resources	Projects executed as part of 2023 RFP and additional procurement activities and included in PGE's base portfolio: Biglow Optimization, Wheatridge Expansion, Meadowlark Battery Energy Storage System (BESS), and Nottingham BESS.
	Fuel Limits	Revised natural gas fuel capacity from PGE MONET model
	Wind Shapes	Appended actual generation for Biglow, Tucannon & Wheatridge through 2023.[246]
Demand	May '26 Corporate Load Forecast (CLF)	Updated load forecast as described in C.2.1.2. Includes refreshed binning of load for stochastic matching, as discussed in 2023 CEP/IRP Update - Aug. 2024 Roundtable.[247]

[244] 2019 IRP update with appendix K at p.75
[245] Minimum and maximum hourly dispatch values for Rock Island and Rocky Reach projects reference data provided by Chelan PUD.
[246] Observations for Biglow were limited to dates prior to Jan. 1, 2021. This difference is intended to exclude observations of recent degradation of the Biglow plant which is expected to return to pre 2021 generation levels because of recent contracts to redesign and maintain existing turbines at the plant.
[247]https://assets.ctfassets.net/416ywc1laqmd/2ZmEDrHLM2VJl60Mw3UjJP/60d5cefcc6c917159575c51141e9920f/IRP_Roundtable_August_24-4.pdf

Category	Update	Description & Source
Methodological	1-day-in-10 reliability metric (1-in-10)	Updated PGE reliability metric interpretation to align with best practice and WRAP Business Practice Manual (BPM) 102.

H.5.2 VPP Capacities

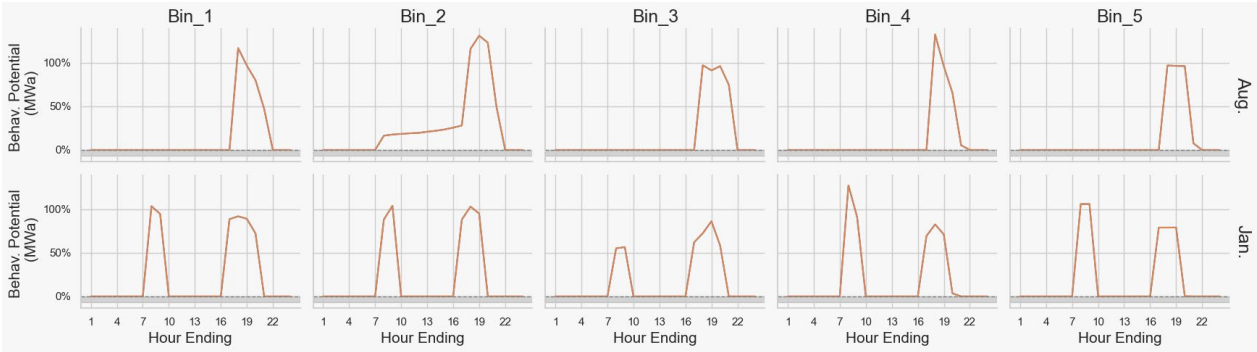
Previous iterations of PGE's IRP included forecasted quantities of VPP capacity as part of the base portfolio used in resource adequacy analysis. Quantities are estimated using PGE's AdopDER model. In contrast, the 2026 CEP/IRP defines five bins of flexible load resources and one group of Dispatchable Stand-by Generation (DSG) resources, as shown in Table 80. Capacity quantities for these six groups of VPP resources are representative of 2025 year ending actuals.

Table 80. Summary of VPP Resource Assumptions in Sequoia

VPP Group	Base Capacity – Summer / Winter (MW)	2030 Cumulative Incremental Potential – Summer / Winter (MW)	Programs
Flexible Load - Bin 1	94 / 47	20 / 11	Residential Smart Thermostat, Energy Partner - Sch. 26
Flexible Load - Bin 2	25 / 15	17 / 5	Peak Time Rebates, Time-of-Use
Flexible Load - Bin 3	11 / 8	6 / 3	Multi-family Water Heater, Energy Partner – Sch. 25, Residential Smart Charging, Non-Residential Smart Charging, Residential Storage, Non-Residential Storage
Flexible Load - Bin 4	5 / 6	12 / 12	Energy Partner – Cold Storage, Multi-Family Ductless Heat Pump, Electrification – Air-Source Heat Pumps, Electrification – Smart Electrical-Resistance Water Heater
Flexible Load - Bin 5	5 / 7	10 / 17	Energy Partner – Agriculture, Microgrids, Fleet Charging, Single-Family Water Heater
Dispatchable Stand-by Generation	154 /154	220 / 220	Schedule 200

PGE simulated capacity contributions of flexible load resources using predetermined flex load shapes. Binned shapes are derived from PGE's AdopDER model and represent the behavioral potential of a related flex load program. This behavioral potential is derived from historical PGE events and weighted by enrolled MW. For example, Figure 177 shows Bin 1's shape, which includes Residential Smart Thermostat and Energy Partner – Schedule 26 programs. During August hour-ending 18:00, the resource provides roughly 110% of the summer program's average MW potential. See Figure 177 for more information.

Figure 177. VPP Bin Shapes in Summer and Winter



Two (2) abstractions are made to capture the call-limited nature of flexible load programs with respect to the modeling limitations of Sequoia. As Sequoia simulates dispatch across a one-week sample (168 hours) with no memory from one week to the next, this modeling framework does not allow for the ability to directly capture call limits of the respective programs. As such, shapes are assumed to only provide value in the months of July and August in Summer and December and January in Winter and the shapes are only present on the days where load is greater than the 80th percentile for a given month.

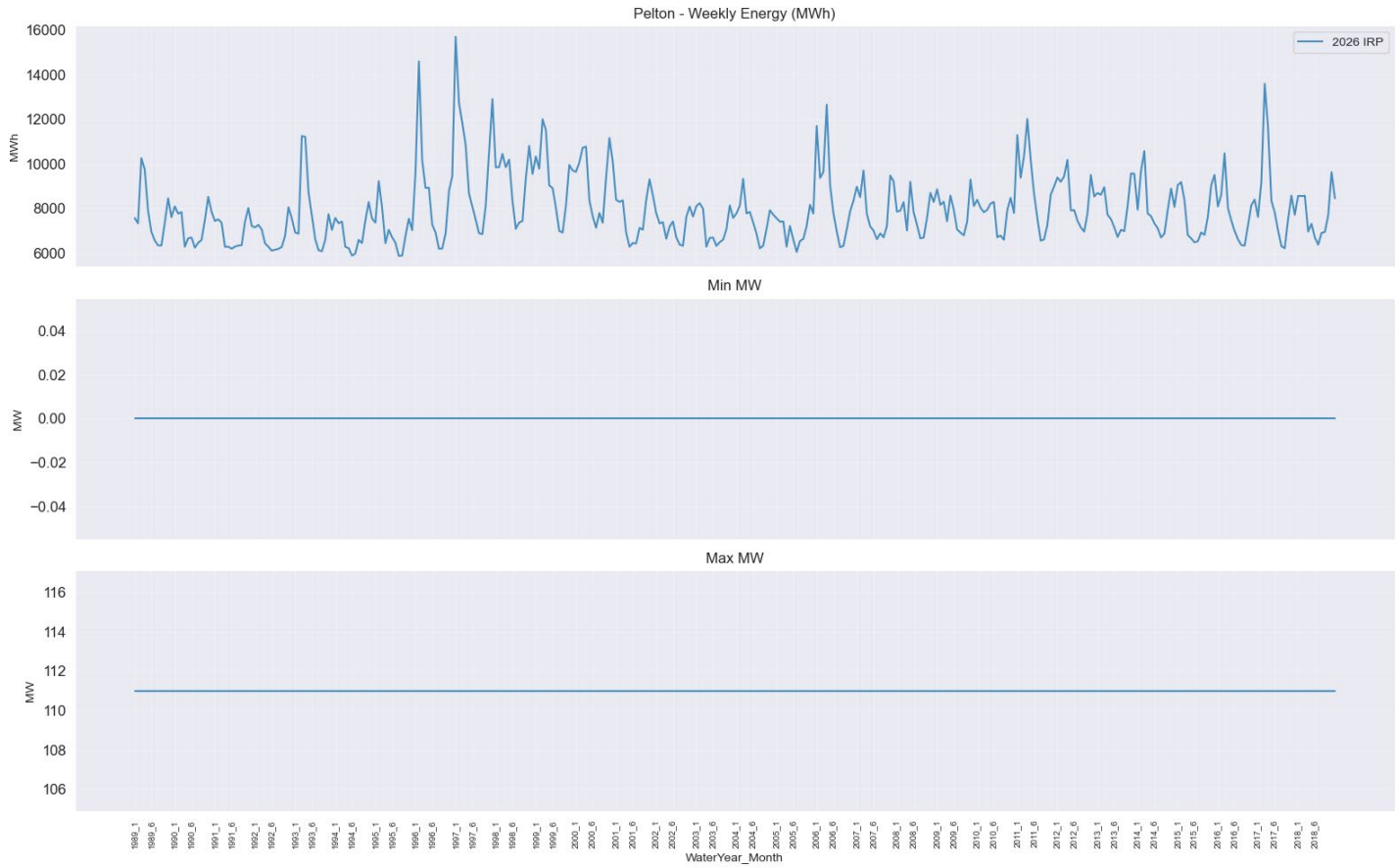
Further, PGE exogenously estimated the ELCC of incremental Schedule 200 Dispatchable Stand-by Generation (DSG) capacity as part of the 2026 CEP/IRP. Given the DSG's unique operating limits, reliability role, and forecasted 220 MW of incremental capacity by 2030, the decision to calculate the ELCC ex-post to Sequoia's constrained optimization dispatch is in effort to explicitly model the 50-hour per year operational constraint of these resources. [248] The DSG as modeled for the 2026 CEP/IRP is comprised solely of reciprocating internal combustion engines (RICE).[249] These resources fall under the United States Environmental Protection Agency (EPA) National Emissions Standards for Hazardous Air Pollutants (NEHAP) regulations, and recent federal interpretation of this rule states that DSG resources can operate up to 50 hours per-year as part of federal initiatives to maintain affordable and reliable power supply considering forecasted load growth from manufacturing and datacenters.[250] To explicitly capture the 50-hour per year operating limits, Sequoia's year 2030 loss-of-load hour (LOLH) curve was adjusted after the constrained optimization dispatch, as if the DSG is the marginal resource operating with perfect foresight. The 50-hour per year limit was divided proportionally between summer and winter given 2030 LOLH observations. Hours of greatest shortfall are reduced by the incremental DSG potential up to assumed operating limits and the resulting capacity need recalculated based on the 1 event-day in 10-years planning standard.

[248] Sequoia's model framework dispatches across 168-hour simulations that are memoryless from one week to the next, inhibiting an endogenous assessment of DSG resources with respect to the 50-hour call limits
[249] 30 MW of Battery Energy Storage Systems are scheduled for operation by 2027 as part of PGE's DSG portfolio. However, given current uncertainty about the operational limitations of these resources they are not included as part of the DSG portfolio. PGE will reevaluate how to include these BESS resources in subsequent IRP iterations.
[250] Trump Administration Announces Regulatory Interpretation of RICE NESHAP.

H.5.3 Hydro Inputs

Hydroelectric projects with storable capacity can help shape supply to meet load. The 2026 CEP/IRP updated assumptions for six hydro projects that provide shaping capacity: Pelton, Pelton ReReg, Round Butte, Priest Rapids, Wanapum and Wells. These projects require three primary parameters for modeling in Sequoia: weekly energy budget (MWh), minimum hourly output (MW), maximum hourly output (MW). Weekly energy budget for the six (6) projects was updated based on Bonneville Power Administration's 2024 Loads and Resources (Whitebook) dataset for regulated projects. This data set forecasts project specific monthly average generation (MWa) for years 2026 through 2035 across 30 historical water years. PGE took the mean of monthly average generation by project for years 2030-2035 multiplied by 168 (hours in a week) to derive weekly energy budgets across all water years. The method for deriving minimum and maximum hourly generation was unique to a projects type (Dispatchable, Mid-Columbia, Run-of-River). Dispatchable projects, Pelton and Round Butte, are owned by PGE and can store energy in ponding. Historical operational data was used to define minimum and maximum hourly limits for dispatchable projects. Hourly limits for Mid-Columbia projects (Priest Rapids, Wanapum, Wells) reflect observed monthly values from PGE's 2026 Annual Update Tariff, scaled based on PGE's share of the project. Hourly limits for the Run-of-River project (Pelton ReReg) use data from the Whitebook, as the maximum of the MWa or MWa scaled by annual percentile across the 30 water years. Figure 178 – Pelton Hydro Parameters below shows an example of the weekly energy (top panel), minimum hourly capacity (middle panel) and maximum hourly capacity (lower panel) constraints for Pelton hydro project. Across all water years the project has an average weekly energy constraint of 7,953 MWh, a minimum hourly capacity of 0 MW, and a maximum hourly capacity of 111 MW.

Figure 178. Pelton Hydro Parameters



H.5.4 Intertie Transfers

Sequoia's supply portfolio includes expectations of intertie transfers into PGE's balancing authority (BA). These transfers are a measure of the diversity benefit in loads and supply across the Western Electrical Coordinating Council (WECC) that PGE could reasonably assume to import into its BA for reliability purposes. Entities in the WECC are undergoing many transformations like those PGE is experiencing. Large load growth, retirement of fossil fuel generation, integration of renewables and grid scale storage, regional resource adequacy programs, and expanded day-ahead markets are influencing demand, supply and coordination across the WECC. While these dynamics make estimating future market surplus challenging, they do not negate the need to derive reasonable estimates of the market's resource adequacy benefits.

In the past two (2) planning cycles, PGE used a regional load-resource balance model to estimate market surplus.[251] This model, initially created by the consultancy Energy and Environmental Economics (E3) for the 2019 IRP, estimated future market surplus through a review of the Bonneville Power Association's (BPA) Loads and Resources Study and the Northwest Power Conservation Council's regional Adequacy Assessment. This model of the region's net capacity position was used

[251] See 2023 CEP/IRP Appendix G

to derive hourly inputs for Sequoia, summarized in Table 81. Overall the model suggested the region would become increasingly constrained in both summer and winter.

Table 81. 2023 CEP/IRP Hourly Intertie Transfer Capability Summary

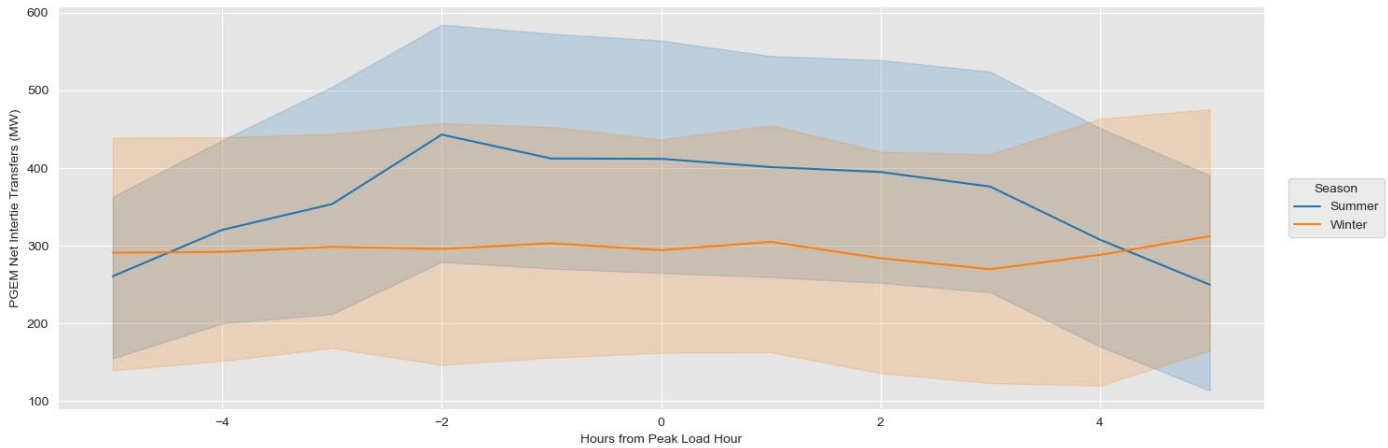
Season	Heavy-Load Hour Intertie Transfer Capability (MW)
Winter	100
Spring	200
Summer	0
Fall	200

In the years following the 2023 CEP/IRP the California Independent System Operator (CAISO) experienced approximately 200% growth in grid-scale storage capacity, from roughly 4GW in 2022 to over 12 GW in 2024.[252] This growth fundamentally altered the WECC resulting in summer surpluses much greater than those assumed in PGE's previous IRP. The highly dynamic nature of western energy markets motivated a change in approach for deriving intertie transfer estimates for the 2026 CEP/IRP.

For the 2026 CEP/IRP, PGE elected to derive hourly estimates of market surplus through an empirical analysis of the company's historical intertie transfers during recent reliability events. Using data from 2021-2024, PGE analyzed hourly intertie transfers during 24 of the heaviest load days. These 12 winter and 12 summer days had daily peaks above the 97th percentile by season. These data included observations from recent weather events that are representative of reliability constrained conditions for the Pacific Northwest, including the 2021 heat-dome summer event and the 2024 January cold snap winter event. Figure 179 displays average hourly intertie transfer during these 24 days, suggesting that PGE imported approximately 400 MW at peak hour during the summer and 300 MW during the winter.[253]

[252] https://www.caiso.com/documents/2024-special-report-on-battery-storage-may-29-2025.pdf
[253] Data excluded intertie transfers from PGE pseudo-tied assets, contracted counterparties, and 12 entities committed to Markets plus as of October, 2025.

Figure 179. Average Hourly Intertie Transfers During Peak Load Days 2021-2024



These averages define seasonal heavy-load hour maximums for available intertie capability during winter and summer during PGE's heaviest load days, as shown in Table 82.

Table 82. 2026 CEP/IRP Hourly Intertie Transfer Capability Summary

Load Percentile	Load Bin	Summer		Winter		Spring			Fall	
		LLH		HLH	LLH	HLH	LLH	HLH	LLH	HLH
0-20th	1	942	942	942	942		942	942	942	942
20th-40th	2		942	942	942	942	942	942	942	942
40th - 60th	3	942	942	942	942		942	942	942	942
60th - 80th	4		942	400	942	300	942	500	942	500
80th - 100th	5	400	400	300	300		942	500	942	500

From these maximum values on heaviest load days, heuristic step changes of increased intertie transfer capability represent decreased risk in shoulder seasons on days with lighter load. On load days less than the 60th percentile it is assumed that the company can utilize all its long-term firm rights (942 MW) to import energy from Pacific Power West and California-Oregon Border.

H.5.5 Qualified Facilities

Sequoia uses monthly estimates of Qualified Facility (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. (QF) capacity estimates align with contracted and online resources and include two assumptions or realization and renewal 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% of the MW will reach operation. Second, a 75% renewal rate of QF

capacity is assumed after contract termination. Estimated MW for January 2030 are listed in Table 83, compared against the 2023 CEP/IRP Update modeling assumptions. More detail on QF assumptions for this planning cycle is further described in Appendix Section F.2.8.

Table 83. 2030 Qualified Facility Capacity by Resource Category

Modeled QF Resource	2030 (MW)
PV East	234.25
PV West	137.22
Biomass	10
Wind	9
Biogas	7.84
Hydro	7.13

H.5.6 2023 Request for Proposal Resources

In 2025 PGE executed agreements for 1015 MW of renewable generation and storage projects as part of the 2023 RFP process and additional procurement activities.[254] These four (4) executed projects are included in Sequoia's base portfolio as part of resource adequacy assessment and are modeled as:

- Biglow Optimization: 125 MW Solar and 125 MW BESS
- Project collocated at PGE's existing Biglow wind facility in Sherman County, Oregon. The BESS resource is modeled with the capability to charge from both wind and solar generation.
- Wheatridge Expansion: 240 MW Solar and 125 MW BESS
- Project collocated at PGE's existing Wheatridge wind, solar, storage facility in Morrow County, Oregon. The BESS resource is modeled with the capability to charge from both wind and solar generation.
- Meadowlark: 200 MW BESS
- Nottingham: 200 MW BESS

These projects are further described in Appendix Section F.2.

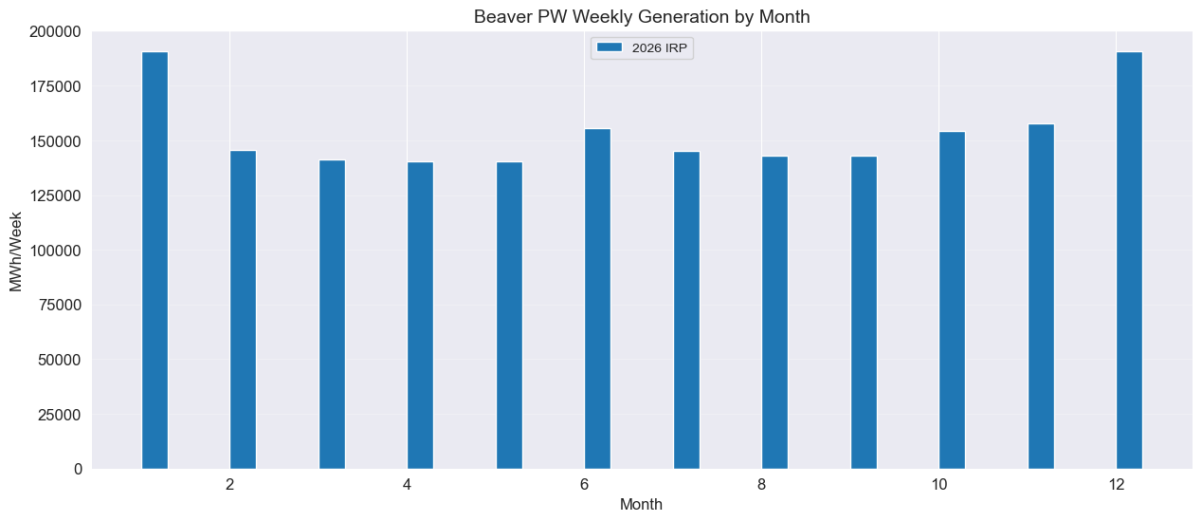
H.5.7 Natural Gas Fuel Limits

Sequoia models weekly fuel limits for two (2) gas zones, Boardman and Port Westward. These limits represent firm fuel constraints for PGE's natural gas generation units east and west of the cascades. No firm fuel constraint for facilities east of the cascades is assumed. PGE updated limits for the Port Westward gas zone to capture firm fuel limits for Beaver and Port Westward gas plants. Updated fuel limits represent constraints along the Northwest Pipeline and Kelso-Beaver Pipeline and

[254] https://investors.portlandgeneral.com/static-files/7f623247-f81f-4075-8f7b-a73268a8fbcf

account for PGE's ability to store and withdraw fuel from the North Mist natural gas storage facility. Resulting weekly limits in MWh/week are shown in Figure 180.

Figure 180. Beaver PW Weekly Generation by Month



Weekly fuel budgets reflect PGE's current firm fuel limits and storage capacity. Values are adjusted to assume a shift of summer withdraws to winter withdraws, reflecting increasing winter energy constraints across in PGE's system and the greater Pacific Northwest.[255, 256] Using 2026 AUT values for fuel consumption at plants west of the cascade, 2026 CEP/IRP Fuel limits are defined as the maximum of: 1) the floor of availability in any month as the firm transfer capacity on Kelso-Beaver pipeline, 2) an adjusted floor reflecting insertion/withdraw from North Mist estimated through historical fuel consumption, including summer withdraws shifted to winter months, 3) a reliability planning quantity which captures the ability to switch from planned injection activities to support operations with a 33% inventory level able to support 16 hours of capacity needs.

H.5.8 Wind Shapes

The 2026 CEP/IRP updated generation shapes for PGE's existing wind facilities, Biglow, Tucannon, and Wheatridge. Observed generation data from 2019 through 2024 are appended to or replace Sequoia's existing generation shapes for wind resources. Biglow observed data from 2019 through 2020 are appended to existing data, creating a data set of hourly data from 2012 through 2020. Data after 2020 are omitted from the sample for Biglow as a reflection of the planned maintenance and redesign of existing assets assumed to return generation to levels like those prior to the declines observed beginning in 2021. Generation data for Tucannon was appended in full, while actual generation data for Wheatridge from 2021-2024 replaced modeled generation data that was used in the past IRP.

[255] 2023 CEP/IRP Update – Section 6.2.3.1 Energy sensitivity adequacy assessment of Preferred Portfolio. p 154
[256] Resource Adequacy and the Energy Transition in the Pacific Northwest. Energy and Environmental Economics. 2026

H.5.9 Load Forecast

The May 2026 Corporate Load Forecast, as described in Appendix Section H.8, is used for capacity assessment. The 2030 version of this same forecast is used to define Day-types used to match load and variable energy resources for plausible sample weeks. A Day-type is a categorical bucket (1–5) that groups days by their percentile-ranked average daily load relative to other days in the same month and weekday, with 1 representing lower-load days and 5 representing higher-load days. Day-types are described in the 2019 IRP Update – Appendix K.1.1.

H.5.10 One-day-in-10 Reliability Metric

PGE updated its interpretation of the "1-day-in-10-years" resource adequacy reliability standard to better align with regional planning conventions and industry guidance. In prior resource adequacy assessments, beginning with PGE's 2016 IRP's RECAP model, the standard allowed 24 cumulative hours of loss-of-load expectation (LOLE) over a ten-year study horizon.[257] This interpretation was transitioned to Sequoia as part of the 2019 IRP Update.[258] More recent interpretations adopted by regional entities, including the Western Resource Adequacy Program (WRAP) and Regional Organization of Western Energy (ROWE), define the standard in terms of the probability of experiencing at least one loss-of-load event day within a ten-year period.[259, 260] In an effort to align PGE's resource adequacy assessment with these regional entities, the capacity need for the 1-day-in-10 years standard is determined by integrating the observed loss of load hours from a simulation up to:

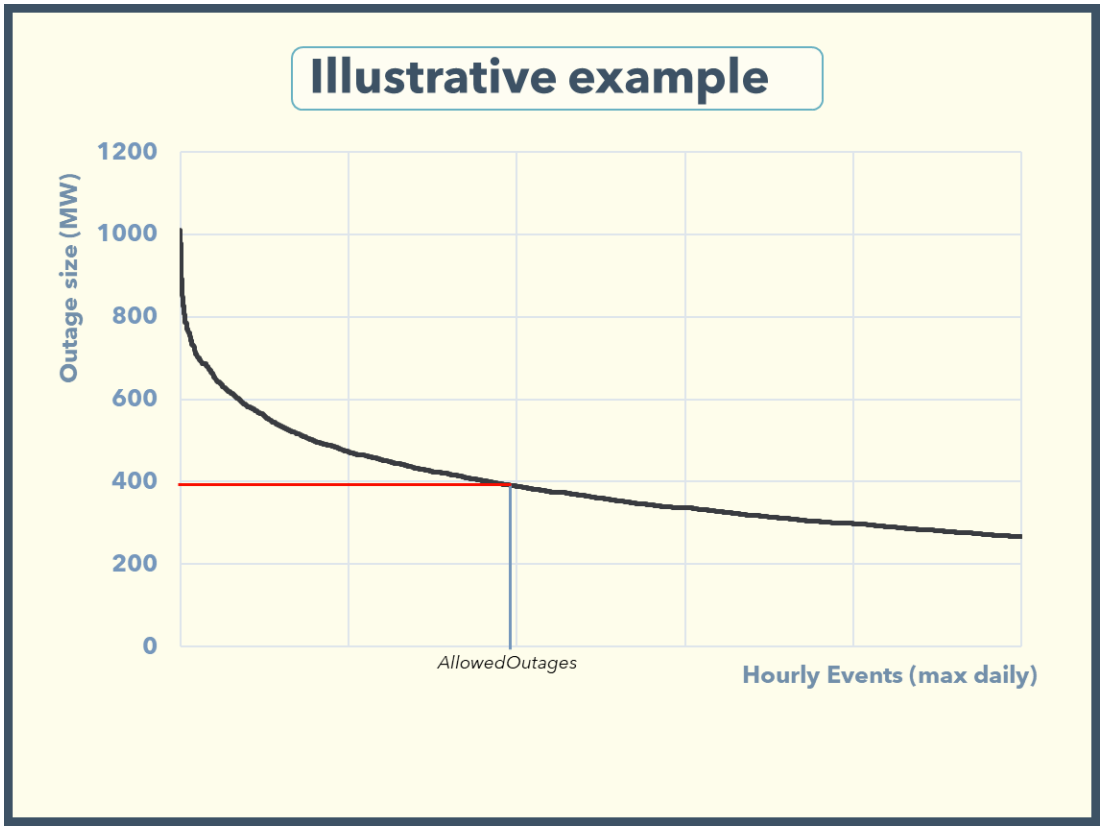
Equation 2. One-day-in-10 Years Capacity Need

$$AllowedOutages = \frac{.1}{365} * SimulatedDays$$

Where AllowedOutages represents the index of the unserved energy observation on the rank sorted loss of load curve resulting from a standard RA simulation in Sequoia where SimulatedDays is equal to 350,000, or 50,000 weeklong simulations. Figure 181 shows an illustrative example of a loss of load curve used to define capacity need, where the capacity need associated with the allowed number of outages is approximately 400 MW.

[257] PGE 2016 Integrated Resource Plan. p 116
[258] PGE 2019 IRP Update. p 81
[259] Clarifying the Interpretation and Use of the LOLE Resource Adequacy Metric. Gord Stephen, et. al. 2024,
[260] WRAP Business Practice Manual 102 – Forward Reliability Metrics

Figure 181. One-day-in-10 years illustrative example



H.5.11 Contingency Reserve Obligations

Sequoia models withholding 3% of load and 3% of generation for contingency reserve obligations in accordance with NERC Regional Reliability Standard BAL-002-WECC-3.[261] On April 14, 2026, FERC approved the retirement of this WECC specific reliability standard, finding that it requires BA's in the WECC to "maintain reserves at levels that exceed those required under the continent-wide Reliability Standard BAL-002-3 Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event."[262] This change is expected to reduce the quantity of contingency reserves PGE's balancing authority is required to maintain. Due to the timing of this change, contingency reserves obligations modeled for the 2026 CEP/IRP are in accordance with NERC Regional Reliability Standard BAL-002-WECC-3.

H.6 ROSE-E

ROSE-E is PGE's constrained-optimization capacity expansion model. ROSE-E is used to model the optimal timing, quantity, and mix of resource additions to meet PGE's forecasted load across a wide range of potential future conditions over a 20-year planning horizon. The ROSE-E model consists of

[261] https://www.nerc.com/globalassets/standards/reliability-standards/bal/bal-002-wecc-3.pdf
[262] https://elibrary.ferc.gov/eLibrary/filelist?accession_num=20260414-3054

a series of equations and constraints written in GAMS, many .txt input files, and an objective function that drives the model to a solution using the GUROBI solver.

Constraints in ROSE-E drive resource additions. Portfolios must meet energy and capacity needs while complying with relevant regulatory drivers of resource need. Portfolio's produced in ROSE-E must satisfy all constraints through the addition of new proxy resources while minimizing the net present value of the revenue requirement (NPVRR) over a 20-year planning horizon. In the proceeding sections ROSE-E's key constraints, inputs, outputs, and assumptions are described in detail.

H.6.1 Energy Constraint

All portfolios produced in ROSE-E are subject to monthly energy constraints. The energy constraint requires that the sum of energy produced by PGE's existing portfolio of owned and contracted resources plus the energy from new resources be greater than or equal to forecasted load, on a monthly basis. Energy need is PGE's forecasted load minus energy generation from existing owned and contracted resources in PGE's portfolio. ROSE-E's energy need input is defined in terms of average megawatts (MWa) for each month of the 20-year analysis time-horizon.

ROSE-E relies on an energy need input that identifies the remaining energy need after accounting for the contribution of all existing non-emitting resources in PGE's portfolios. This is calculated as the forecasted load minus energy generation from existing non-emitting generation. Non-dispatchable resources in PGE's portfolio are modeled using fixed monthly generation shapes for each resource.

The remaining energy need must be met using a combination of available energy from existing dispatchable emitting sources and new resource additions. Energy from existing dispatchable emitting resources in PGE's portfolio goes into ROSE-E as an annual amount of energy available from each emitting facility, which is then distributed across the months of each year in a co-optimized manner with the addition of new resources within the ROSE-E optimization. The quantity of energy that can be allocated in each month is limited by maximum output by plant. ROSE-E allocates the energy across months in the manner that compliments the fixed generation shapes of new resource additions to meet the energy need in each month in a way that minimizes the cost of adding new resources. The amount of emitting energy available to meet energy needs varies across scenarios depending on assumptions about PGE's base portfolio and regulatory constructs.

Proxy resource options are defined in ROSE-E with monthly capacity factors. In order to minimize costs, ROSE-E is incentivized to select resources with monthly generation shapes that align with the seasonality in monthly energy need that results from the shape of PGE's load and existing portfolio of resources. PGE's energy position is described in Appendix Section H.9.2.

H.6.2 Capacity Constraint

All portfolios produced in ROSE-E are subject to seasonal capacity constraints. Capacity needs must be met for both summer and winter of each year. ROSE-E meets capacity needs through the Effective Load Carrying Capability (ELCC) of new resource additions. See Section 6.5 and Appendix Section G.6 for more detail on ELCCs. Each proxy resource option is defined in ROSE-E with distinct

summer and winter ELCC curves. ELCC curves are defined to capture the declining marginal capacity contribution of each resource.

Most portfolios in ROSE-E rely on capacity needs and proxy resource ELCCs that are produced in the Sequoia model. Proxy resource ELCCs are described in Section 6.5 New Resource Capacity Contributions and PGE's capacity position is described in Section 6.6.1.2 Capacity Needs. The State Reliability Metrics scenario relies on alternative capacity need and ELCCs that are produced using alternative methods described in Appendix Section H.10.

H.6.3 RPS Constraint

All portfolios in ROSE-E are subject to an annual renewable portfolio standard (RPS) constraint. PGE's forecasted RPS obligation is calculated as a percent of retail sales in each year and is represented in MWa. In each year of the analysis, RPS obligations must be met using a combination of retirement of renewable energy certificates (RECs) from PGE's existing REC bank, forecasted REC generation from PGE's existing portfolio, and RECs generated from new non-emitting proxy resources added in ROSE-E. New non-emitting resources added in ROSE-E generate 1 MWa of RECs for each MWa of energy produced. PGE's REC bank contains a mixture of infinite-life and 5-year RECs, while all future RECs generated by new and existing resources are 5-year RECs. Infinite life RECs have no expiration date, while 5-year RECs have a 5-year window in which they can be used for compliance before they expire. PGE's forecasted RPS obligation is shown in Section 6.6.1.3.

H.6.4 Emissions Constraint

Portfolios modeled to comply with HB 2021's GHG emissions targets are subject to emissions constraints in ROSE-E. Emissions in HB 2021 GHG reduction portfolios are constrained by the GHG glidepath to meet HB 2021 targets in 2030, 2035, and 2040, and decline linearly in the intervening years. The quantity of energy retained from emitting sources to serve PGE's retail load is limited to the amount defined in the GHG glidepath. The GHG glidepath is described in Appendix Section I.2 and resulting quantities of emitting energy serving load are summarized in Section 6.6.1.1. In emissions-constrained portfolios, no additional new emitting resources are available for selection. Portfolios that model a Reliability Only regulatory structure are not subject to GHG emissions constraints. For these portfolios, ROSE-E has access to the full output of PGE's existing emitting energy facilities to serve load and has access to a limited quantity of additional natural gas contracts.

H.6.5 Cost Cap Expenditures Constraint

The cost cap expenditures constraint is applied in select portfolios that are modeled under the Continued Progress regulatory structure. Scenarios that model the Continued Progress regulatory environment are designed to test portfolio outcomes in situations where spending on resources to decarbonize results in the triggering of the HB 2021 cost cap provision.

In ROSE-E, the HB 2021 cost cap provision is modeled using a minimum expenditures constraint that requires the model to add non-emitting resources beyond the quantity needed for reliability and RPS requirements. Using the technique, portfolios are produced that make additional progress

toward decarbonization compared to the Reliability Only regulatory environment without the imposition of a GHG-reduction glidepath.

The cost cap minimum expenditures constraint is implemented in ROSE-E by first estimating the cost cap spending budget. The cost cap budget is 106% of the forecasted base revenue requirement, including the cost of incremental resource additions from the Reliability Only portfolio. The HB 2021 cost cap provision and calculation of the cost cap budget are described Appendix Section I.3. Continued Progress portfolios are run with identical assumptions to the Reliability Only scenario, plus a minimum cost cap spending constraint. The cost cap spending constraint requires that expenditures on fixed costs of new non-emitting resources be greater than or equal to the cost cap budget in each year beginning in 2030. Because Continued Progress portfolios have the same energy and capacity needs as Reliability Only portfolios are constrained to have higher expenditures, larger quantities of new non-emitting resources are added. Continued Progress portfolios are subject to the cost minimization objective function as other portfolios.

H.6.6 Transmission Constraints

Off-system resources require transmission to PGE's service territory to be selected in ROSE-E. A limited quantity of resources can be added using quantities of existing available firm and non-firm transmission rights. The quantity of transmission available in ROSE-E is split into firm and non-firm transmission product categories. Resources accessed via non-firm transmission have reduced capacity factors compared to those accessed with firm transmission and do not provide capacity value. The modeling of resources accessed with non-firm transmission is described in Appendix Section H.2.2.6 Non-Firm Transmission Representation in PGE Zone Model. The quantity of firm and non-firm transmission available in ROSE-E is shown in Table 84.

As described in Section 5.1, additional transmission rights within BPA's existing system are significantly constrained. However, PGE has informed ROSE-E assumptions with transmission market intelligence gained in PGE's 2025 All-Source RFP. Bids included in PGE's RFP initial shortlist identified 1570 MW of incremental long-term transmission available transfer capacity (ATC) to deliver energy to PGE's service territory without expansion investments required from PGE.[263] In addition, ROSE-E incorporates an additional 270 MW of transmission from Colstrip. Each MW of firm transmission ATC allows access to 1.33 MW of resources, requiring that 75% of new resources have firm transmission rights. With the 75% transmission requirement, the 1840 MW of firm transmission ATC provides access to 2453 MW of off-system renewables. The quantity of non-firm transmission available in ROSE-E is based on analysis of the average headroom for the North of Pearl Flowgate in 2035. This analysis identified 1380 MW of non-firm transmission and is described in Appendix . Each MW of non-firm ATC provides access to 1 MW of off-system resources. Firm and non-firm quantities of transmission available in portfolio analysis are summarized in . The available transmission is allocated across proxy resource zones, with multiple resources within each zone

[263] See PGE's 2025 RFP Final Shortlist filing, p8: https://edocs.puc.state.or.us/efdocs/HAH/um2371hah345181028.pdf

sharing access to the zone's ATC. Proxy resource zones and the resources contained within each are shown in Table 84.

Table 84. Transmission Available by Resource Zone

Transmission Zone Name	Firm Transmission ATC	Non-Firm Transmission ATC	MW of Resources Available
Christmas Valley	-	-	-
Gorge	750	-	1000
McMinnville	-	-	-
Montana[1]	490	-	653
SE Washington	600	-	800
Non-Firm	-	1380	1380
Total	1840	1380	3833

[1] 270 MW of the MT ATC becomes available in 2035.

Table 85. Proxy Resources by Transmission Zones

Transmission Zone Name	Proxy Resource
Christmas Valley	Christmas Valley Solar
	Christmas Valley Hybrid
Gorge	Gorge Wind
	Wasco Solar
	Gorge Hybrid
McMinnville	McMinnville Solar
	McMinnville Hybrid
Montana	Montana Wind
	Montana Hybrid
SE Washington	SEWA Hybrid
	SEWA Wind
Non-Firm	Gorge Wind_NF
	SEWA Wind_NF
	Christmas Valley Solar_NF
	McMinnville Solar_NF
	Wasco Solar_NF
	Christmas Valley Hybrid_NF
	McMinnville Hybrid_NF
	Gorge Hybrid_NF

Transmission Zone Name	Proxy Resource
	SEWA Hybrid_NF

H.6.7 New Proxy Resource Options

ROSE-E relies on proxy resources that represent generalized versions of the variety of resources reasonably expected to be available for acquisition by PGE. Proxy resources do not capture project-specific costs or characteristics. The proxy resources included were selected to span a range of resource types and locations to capture a wide variety of options. When ROSE-E was first introduced in PGE's 2019 IRP it included 16 proxy resources options. In the 2026 CEP/IRP, the number of proxy resources represented in ROSE-E has grown substantially to 83 options, allowing consideration of wider variety of resource types and locations. Each proxy resource type available for selection in ROSE-E is described in the proceeding sections.

ROSE-E selects an optimal combination of timing and quantity of resources additions from the available proxy resources for meeting energy and capacity needs based on the combination of characteristics that define the costs and benefits of each resource option. To define these characteristics for each resource, ROSE-E relies on the inputs shown in Table 86.

Table 86. Proxy Resource Characteristics

Characteristic	Units	Upstream Model	Temporal Granularity
Capacity Factor	Percent	Aurora PZM	Monthly
Energy Value	$/MWh	Aurora PZM	Annual
Variable Cost	$/MWh	Aurora PZM	Annual
Fixed Costs	Real-levelized $/kW-year	LUCAS	Annual
ELCC	MW of accredited capacity	Sequoia	Seasonal
Availability	MW/yr & total MW	None	Annual

The timing and quantity of availability of resources is defined through a combination of multiple inputs. Availability of each resource is defined in terms of the total potential MWs available throughout the planning horizon and the annual maximum MWs in each year. Most resources can be added in 1 MW increments but a limited numbers of resources have unit size constraints that dictate that additions be made in a larger incremental amount.

Many of the characteristics that define proxy resources flow into ROSE-E from other models that are upstream in PGE's IRP modeling environment. Energy value, variable cost, and capacity factor are estimated in the Aurora PZM, which is described in Appendix Section H.2.2. Proxy resource ELCCs are estimated in Sequoia (Appendix Section H.5).

Fixed costs of proxy resources are estimated in PGE's LUCAS model (Appendix Section H.3). Tax credits are accounted for in the fixed costs of a limited quantity of renewable resources. PGE's assumptions about tax credits for new resources are described in detail in Appendix Section G.7.4.

The quantity of renewable resources that include tax credits is limited in ROSE-E to the expected procurement amounts from the final shortlist of PGE's 2025 RFP. Project development of resources beyond the quantity being sought in the 2025 RFP final shortlist are not expected to occur on timeliness consistent with qualifying for tax credits. In line with this assumption,1000 MW of Gorge Hybrid is available with tax credits in 2029 and 2030. Amongst the proxy resource options in ROSE-E, the location and combination of resources accessed using the Gorge Hybrid proxy resource provides the best approximation of the resources in the 2025 RFP final shortlist. This 1000 MW of hybrid resource contains 2340 MW of total resources (1000 MW of wind, 667 MW of solar, and 667 MW of 4-hr storage) behind 1000 MW of interconnection.[264] Flexibility value and integration costs, as described in Appendix Q, are also accounted for in new resource fixed costs.

H.6.7.1 Utility-scale Renewable Resources

ROSE-E has access to utility-scale renewable energy resources in a variety of geographic locations in the PNW and across the West. The variety of locations provides ROSE-E with access to a range of generation profiles from which to match shapes of energy and capacity benefits with timing of needs. Utility-scale renewable energy options are available as standalone wind or solar resources and as hybrid configurations paired with storage. Standalone renewable options in ROSE-E are:

- Gorge wind
- Montana wind
- SE Washinton wind
- Wyoming wind
- North Dakota wind
- Offshore wind
- Wind repower[265]
- McMinnville solar
- Christmas Valley solar
- Wasco solar
- Nevada solar

[264] Resource availability is ROSE-E is described in terms of the number interconnection MWs. For standalone renewables and storage, there is 1 MW of resource behind each MW of interconnection, so the quantity of resources is equal to the interconnection MW. For hybrid resources, there are multiple MWs of resources behind each MW of interconnection, so the quantity of resources ultimately reported in portfolio summaries is larger than the quantity of MWs in ROSE-E terms. For each MW of solar hybrid (Christmas Valley and McMinnville hybrids) available in ROSE-E, 2 MWs of resources can be added to the portfolio because there is 1 MW of solar and 1 MW of storage behind a 1 MW interconnection. For all other hybrids (Gorge, SEWA, MT, and ND), there are 2.34 MWs of resources for each 1 MW of availability in ROSE-E because behind each MW of interconnection there is 1 MW of wind, 0.67 MW of solar and 0.67 MW of storage.
[265] The wind repower resource represents the incremental costs and benefits of repowering an existing wind facility. Wind repower is assumed to rely on existing transmission from the facility and does not require incremental transmission. The wind repower option has a unit size constraint that requires that it be added at full size of 267 MW.

H.6.7.2 Standalone Storage

Four standalone proxy storage resource options are included in ROSE-E.

- 4-hr battery
- 6-hr battery
- 10-hr pumped hydro storage
- 100-hour storage

4-hour, 6-hour and 100-hour standalone storage resources are assumed to be on-system and do not require transmission. Pumped hydro facilities rely on specific geographic locations that have the necessary topography and water resources. Because of the geographic specificity of pumped hydro facilities, the pumped hydro proxy resource is assumed to be off-system and requires transmission to PGE's service territory in order to be added in ROSE-E. In ROSE-E, pumped hydro can be accessed via the Blueprint South transmission option. In order to approximate a reasonable procurement schedule for other standalone storage resources, the following maximum annual procurement limits are set.

- 4-hour battery: Availability in the near-term is aligned with the 2025 RFP final shortlist. Starting in 2032, 500 MW/yr of 4-hr storage is available for selection. This approximates a reasonable procurement schedule but is not tied to specific procurement targets from the RFP.
- 6-hour battery: Based on evidence gleaned from bids received in the 2025 RPF, 4-hr battery storage appears to be the preferred configuration in the market today. Consistent with this observation, 6-hour storage is generally not made available for selection in portfolios in this planning cycle.
- Pumped hydro storage: Pumped hydro is available beginning in the same year that transmission access becomes available. Because of procurement limitations created by transmission requirements, there is no annual procurement limit on pumped hydro.
- 100-hour storage: 100 MW/yr is available for selection starting in 2030. This approximates a reasonable procurement schedule but is not tied to specific procurement targets from the RFP. Because long duration storage does not currently exist in large amounts on the grid, PGE believes smaller annual quantities than are assumed for 4-hour storage appropriately capture a reasonable procurement cadence.

H.6.7.3 Hybrid Resources

ROSE-E has access to several configurations of renewables plus storage hybrid resources. Hybrid resources are off-system and require transmission. Solar plus storage proxy hybrids contain a 1:1 ratio of solar to storage, with 1 MW of solar and 1 MW of storage behind each 1 MW of interconnection. Solar plus storage hybrids are available in three locations.

- Christmas Valley hybrid
- McMinnville hybrid

- Wind optimization[266] – 179 MW

Triple hybrids pair wind, solar, and storage behind a common point of interconnection. For each MW of these resources added to the portfolio, behind the interconnection there is 1 MW of wind, 0.67 MW of solar, and 0.67 MW of storage. Triple hybrids are available in four locations.

- Gorge hybrid
- SE Washington hybrid
- Montana hybrid
- North Dakota hybrid

H.6.7.4 Community-Based Renewable Energy

Community-based renewable energy resources (CBREs) in ROSE-E are represented by a single on-system proxy resource representing hybrid solar plus storage microgrid. The cost and quantity of CBREs available is informed by PGE's CBRE RFO. ROSE-E has access to a total of 110MW of CBREs throughout the planning horizon. In the years 2027-2030, 66 MW of CBREs are available for selection at a cost consistent with bids received in the RFO. From 2031-3035, an additional 44 MW of CBREs are made available at a lower cost that contemplates the rCBI benefits that would be required to bring the cost of CBREs in line with the cost of traditional utility-scale resources. The details underlying these assumptions are described in Appendix Section G.3.

H.6.7.5 Virtual Power Plant

Virtual Power Plant (VPP) resources are available for selection in ROSE-E for the first time in the 2026 CEP/IRP. There are two (2) types of VPP resources available for selection.

Distributed generation resources (DSG) available for selection in ROSE-E represent diesel-powered backup generators that provide capacity-only (no energy benefit) in ROSE-E. The characteristics of DSG resources are described in Appendix Section G.2. All scenarios except those that include Core Growth Only have access to 219 MW of DSG resources. DSG is not available for selection in Core Growth Only scenarios because the DSG forecasted growth is associated with new Schedule 96 customers.

In past IRPs, forecasted cost-effective quantities of demand response (DR) were assumed to part of PGE's base portfolio, reducing the capacity need that must be met with new resource additions in ROSE-E. In the 2026 CEP/IRP, forecasted cost-effective DR has been removed from PGE's base portfolio and are made available for selection, along with additional quantities of non-cost-effective DR, in ROSE-E. DR resources are sorted into 5 bins for selection in ROSE-E. Each bin is divided into a summer and winter resource that provide either summer or winter capacity, making 10 individual

266 The wind optimization proxy resource represents the incremental costs and benefits of adding solar and storage to an existing wind facility. Wind optimization is assumed to rely on existing transmission from the facility and does not require incremental transmission. The wind optimization option has a unit size constraint that requires that it be added at full size of 179 MW.

resources in ROSE-E. DR characteristics and binning methods are described in Appendix Section G.2.3.

H.6.7.6 Energy Efficiency

Cost-effective quantities of energy efficiency (EE) are accounted for in PGE's load forecast, reducing the energy and capacity need that must be met with new resource additions in ROSE-E. Additional quantities of non-cost-effective (NCE) EE are made available for selection in ROSE-E. The 45 MWa of EE resources in ROSE-E are binned into five proxy resources that provide both energy and capacity benefits. The characteristics and binning methods of NCE EE are described in detail in Appendix Section G.1.

H.6.7.7 Emerging Non-Emitting Resource

ROSE-E has access to an emerging resource that is a generic representation of the variety of dispatchable non-emitting resources that are not yet commercially available to PGE but which may become available in the future, such as small modular nuclear reactors (SMR) and geothermal facilities. While the emerging resource is conceptually representative of a variety of resource types, for modeling purposes, the cost and performance characteristics are based on SMR. These characteristics are described in Appendix Section G.5.5.1 Nuclear. The emerging resource does not require transmission. All scenarios in the 2026 CEP/IRP have access to 500 MW/yr of the emerging resource beginning in 2035.

H.6.7.8 Transmission Expansion and Upgrades

Transmission expansion and upgrade options allow access to off-system resources and market capacity in the form of front-office transactions (FOTs). The transmission options available for selection in ROSE-E are described in Section 5.3. Each transmission option is available for selection within a 5-year window beginning in the year of earliest COD. Transmission options are unit-size constrained and can only be added in the full project size. Resources accessed via a transmission expansion or upgrade option can be added in 1 MW increments at any time beginning in the year the transmission option is added to the portfolio. There is no requirement that the full capacity of the transmission line be utilized through resource additions.

Off-system resources accessed via transmission expansion and upgrades are subject to the same 75% transmission requirement as resources added via existing transmission ATC. As a result, each MW of transmission capacity added through upgrades or expansion allows access to 1.33 MW of off-system resources.

The selection of certain transmission options is dependent on the addition of other transmission options. Transmission dependencies are designed to ensure transmission expansion options are paired with necessary infrastructure for delivery to PGE. Transmission dependencies are:

- WSPP2 is dependent on WSPP1
- Colstrip is dependent on WSPP2
- Blueprint is dependent on WSPP2
- B2H is dependent on WSPP2

- Greenlink is dependent on Blueprint
- SWIPN and Gateway are dependent on B2H
- Only one of either SWIPN or Gateway can be selected

The off-system resources accessed by each transmission option are defined in the following way:

WSPP, Trojan-Harborton, and Cascade Renewables allow access to resources in the Gorge, SE Washinton, Christmas Valley, and McMinnville transmission zones, as shown in Table 85.

- NPC allows access to North Dakota and Montana resources.
- Colstrip allows access to Montana resources.
- Gateway allows access to Wyoming resources.
- Greenlink and SWIPN allow access to Nevada resources.
- Blueprint allows access to pumped hydro storage.

Some transmission expansion and upgrade options provide access to capacity products in the form of bilateral contracts or front-office transactions with peer utilities (FOTs). Transmission options that provide access to market capacity can provide access to market capacity in summer, winter, or both seasons.[267] FOTs resources provide perfect capacity (100% ELCC) and do not supply energy.

Market capacity available through a given transmission option is available in quantities up to the headroom remaining after the maximum available quantity of off-system renewable or hybrid resource has been added. The accredited capacity of the associated renewable or hybrid plus the FOT capacity cannot exceed the capacity of the transmission option. Because the associated renewable and hybrid resources accessed by transmission expansion provide different summer and winter ELCC, the headroom varies by season. The quantity of FOTs available on a transmission line in each season is equal to the size of the line minus the capacity contribution in that season of the maximum quantity of renewable or hybrid accessed.

Once a transmission option has been added to the portfolio, the model can add the FOTs in any subsequent year. Market capacity is available at the annual fixed cost of a 6-hr battery. For market capacity products that provide benefits in only one season, half of the annual cost of the 6-hr battery is incurred. The quantity of available market capacity for each transmission option is shown by season in Table 87.

Table 87. Front-Office Transaction Capacity by Season

	Summer Capacity	Winter Capacity
WSPP	0	327
NPC	40	43
Colstrip	230	116
SWIPN	0	295

[267] Assumptions about transmission market access were informed by a study conducted by consultants at Energy GPS, which were presented at PGE's November 2024 roundtable meeting.

	Summer Capacity	Winter Capacity
Blueprint South	0	304
Clearwater	101	101

H.6.7.9 Capacity and Energy Fill

ROSE-E has access to energy and capacity fill as resources of last resort to meet needs when insufficient access to proxy resources exists due to limitations in resource availability created by assumptions about procurement timelines or transmission constraints. Unlike proxy resource options that remain in the portfolio for the remainder of the study period once they have been added, fill resources are available on an intermittent basis with costs and benefits that can come and go from the portfolio each year. Capacity fill is available to be utilized on a seasonal basis and is reported on an annual basis as the maximum of winter and summer amounts used in each year. Energy fill is available on a monthly basis and is reported on an annual MWa basis as the average of the monthly MWa used across the months of the year. Fill resources are viewed in the cost minimization equation as exceedingly expensive relative to proxy resource options in order to restrict their use to last resort. For cost accounting purposes in the calculation of system costs, fill resources are assigned the cost of a 6-hr battery.

H.6.8 Existing Portfolio Resources

PGE's existing portfolio of resources are accounted for in ROSE-E in several ways. The energy and capacity contributions of existing resources are captured in the energy and capacity need inputs. The existing fixed costs and financial costs and benefits associated with the operation of the existing portfolio are accounted for in the calculation of the NPVRR of each portfolio produced. Existing portfolio costs do not influence resource selection decisions within ROSE-E.

H.6.9 Implementation and Outputs

ROSE-E produces an optimal buildout of resources across the 20-year analysis timeline subject to the constraints and assumptions of each scenario. Each scenario analyzed in ROSE-E is run across multiple futures in order to capture and quantify uncertainty in potential future conditions of key planning variables. In the 2026 CEP/IRP, portfolios are analyzed across 333 different futures that are described in Section 6.6. For each of the 333 futures analyzed a unique set of results is produced, each with a different optimal resource buildout and associated estimate of portfolio costs. For each scenario analyzed, ROSE-E produces outputs describing the timing and quantity of resource additions, the energy and capacity contribution of each resource added, annual streams of costs and benefit (on a levelized basis), REC generation, and portfolio NPVRR. Portfolios produced in ROSE-E are passed for analysis in other models in PGE's modeling environment to test emissions outcomes (Aurora PZM), resource adequacy (Sequoia), and detailed annual cost and risk analysis (ARIA).

H.6.10 Resource Structures

Section 7.3 Scenarios Analyzed characterizes the scenarios analyzed in ROSE-E in terms of variations in key planning structures. Scenarios can vary across a range of assumptions about resource

structure with regards to PGE's existing portfolio and proxy resources available for selection. Key resource structure components and their descriptions are provided in Table 88.

Table 88. Resource Structures

Resource Structure	Description
Base Case	All demand and supply side resource options, except for single and combined-cycle combustion turbines available for selection
Hydro	To evaluate the impacts of additional hydro availability, certain scenarios include a proxy hydro storage resource with cost and performance comparable to hydro transactions executed by PGE in the last five years. Scenarios that include the hydro contract resource include a total cumulative amount of 100 MW in 2027 – 2029 and 200 MW in 2030 – 2046.
Natural Gas	Certain portfolios can select a new contract with an existing natural gas facility, in limited quantities, in addition to the already existing natural gas fleet. The volumes available are estimated based on the assumed availability of existing IPP owned natural gas resources in the region. New natural gas resource builds are recognized as limited in the PNW due to policy, permitting, construction timelines, and the lack of interstate pipeline capacity to support additional gas delivery. Scenarios that include additional natural gas availability have access to 200 MW starting in 2027 and an additional 400 MW starting in 2035. Natural gas contracts are modeled using cost and performance characteristics of the IRP combined-cycle natural gas proxy resource.
Colstrip	Unless otherwise noted, all scenarios have the default assumption of Colstrip exiting PGE's portfolio at the end of 2029 In line with Senate Bill 1547, Colstrip scenarios evaluate the impact of extending Colstrip through the end of 2034.

H.7 ARIA

H.7.1 Introduction

The Analysis of Risk in Investments & Assets (ARIA) model is a new analytical framework being introduced as part of the 2026 Integrated Resource Plan (IRP). ARIA replaces and significantly expands upon the Asset Risk Tool (ART), which PGE previously used to translate the 20-year Net Present Value Revenue Requirement (NVPRR) produced by ROSE-E into annual cost impacts.[268]

While cost translation remains a core function, ARIA extends the analysis beyond annual cost estimation to provide a comprehensive assessment of portfolio financial risk. The model evaluates how each candidate portfolio performs across the broad range of future conditions considered in the IRP, including variations in market prices, load growth, resource performance, policy outcomes, and other key uncertainties.

This expanded capability allows PGE to evaluate portfolios not only on their expected cost, but also on the distribution and magnitude of risks they may face. Rather than focusing exclusively on average outcomes, ARIA provides visibility into the full range of potential portfolio performance,

[268] See PGE's 2023 IRP page 257 and 523 for more details on the prior methodology.

including the likelihood and severity of adverse outcomes. This enables a more robust comparison of portfolios and supports more informed decision-making regarding the tradeoffs between expected cost, cost volatility, and overall portfolio resilience.

By combining annual cost analysis with risk evaluation, ARIA serves as a bridge between portfolio optimization in ROSE-E and portfolio selection in the IRP planning process.

H.7.2 Annual Costs

Portfolio optimization within ROSE-E is performed on a 20-year Net Present Value Revenue Requirement basis. Evaluating portfolios on a present-value basis ensures that investment decisions appropriately account for the time value of money and allow for portfolios with differing investment schedules and resource mixes to be compared on a consistent economic basis.

While NVPRR is appropriate for identifying least-cost portfolios, it does not provide sufficient insight into the timing of costs, or the year-to-year risks associated with portfolio implementation. Understanding these annual cost patterns is important for evaluating customer impacts, assessing exposure to future uncertainties, and identifying periods of elevated financial risk.

To address this need, ARIA reconstructs portfolio costs on an annual basis by recalculating the costs and benefits associated with each portfolio for every year of the study horizon. Resource additions and retirements are held constant with the portfolio selected by ROSE-E; however, ARIA replaces the real levelized cost assumptions used within ROSE-E with nominal annual cash flows that reflect the actual timing of expenditures and benefits.

This distinction is particularly important for resources whose costs and benefits occur in different years. For example, energy efficiency investments often incur most of their costs at the time measures are installed, while the associated energy and capacity benefits are realized over many subsequent years. Within ROSE-E, these impacts are represented through levelized costs, which are appropriate for optimization purposes but do not capture the concentration of expenditures in the year of investment. ARIA preserves the timing of these cash flows, allowing annual cost impacts to be accurately represented and assessed.

For each portfolio and future, ARIA calculates annual revenue requirement impacts by combining:

- Capital costs associated with new resource development and acquisition.
- Costs associated with the existing PGE resource portfolio.
- Fixed and variable operation and maintenance expenses.
- Fuel costs and other operating expenses.
- Energy and capacity market purchases.
- Market sales revenues.
- Flexibility and operational benefits provided by portfolio resources.
- Capacity replacement or fill requirements when portfolios are resource deficient.
- Other portfolio-specific costs and revenues represented within the IRP analysis framework.

The resulting annual cost streams provide a detailed view of when portfolio costs occur, how costs evolve over time, and which components contribute most significantly to portfolio risk. These annual costs serve as the foundation for ARIA's subsequent risk analysis, enabling the model to evaluate not only the expected cost of a portfolio, but also how that cost may vary across a wide range of possible future conditions.

H.7.3 Portfolio Performance

Once annual costs have been calculated, ARIA evaluates the performance of each portfolio across the full range of futures considered in the IRP. While ROSE-E constructs portfolios based on a specific set of assumptions regarding future loads, market prices, and technology costs, actual future conditions are uncertain. A portfolio that performs well under one set of assumptions may perform very differently if those assumptions do not materialize.

To evaluate this uncertainty, ARIA tests each portfolio against all combinations of modeled futures. The future dimensions considered in the analysis include:

- High, Reference, and Low Load forecasts.
- High, Reference, and Low Technology Cost forecasts.
- Thirty-seven distinct market price futures.

Taken together, these inputs create a wide set of possible future conditions under which each portfolio is evaluated. Rather than assessing portfolio performance under a single expected future, ARIA measures how portfolio costs change across the full range of plausible outcomes considered in the IRP.

For each portfolio-future combination, ARIA calculates a 20-year Net Present Value Revenue Requirement (NPVRR) using the annual cost modeling framework. This produces a distribution of possible NVPRR outcomes for every portfolio. All future combinations are weighted equally within the analysis, reflecting the objective of evaluating portfolio resilience across the entire future space rather than emphasizing any single forecast.

Portfolio performance is then summarized using two (2) primary metrics:

- Mean NPVRR, representing the average cost of the portfolio across all future combinations.
- Standard Deviation of NPVRR, representing the variability of those outcomes and serving as a measure of portfolio risk.

Together, these metrics characterize the fundamental cost-risk tradeoff associated with each portfolio. The mean NPVRR measures expected customer cost, while the standard deviation captures the uncertainty surrounding that expectation. A portfolio with a lower standard deviation is expected to produce more consistent outcomes across a wide range of future conditions, while a portfolio with a higher standard deviation may expose customers to greater variability in future costs.

This evaluation framework allows ARIA to move beyond identifying portfolios that perform well under a single forecast and instead identify portfolios that demonstrate strong performance across

many different potential futures. The resulting cost and risk metrics form the basis for portfolio comparison and selection.

H.7.4 Portfolio Optimization and Selection

Although portfolio performance is evaluated across all future combinations, portfolio selection is focused on portfolios that were originally constructed by ROSE-E to meet the Reference Load forecast.

This approach reflects the objective of developing a resource plan that is appropriately sized to meet expected customer demand. Portfolios developed specifically for High Load futures may include resource additions that are unnecessary under expected conditions, while portfolios built for Low Load futures may not provide sufficient resources if demand develops as forecasted. Restricting the candidate set to Reference Load portfolios provides a consistent basis for comparing resource strategies designed to meet expected needs.

ARIA considers both metrics simultaneously when identifying the preferred portfolio. The framework recognizes that portfolios with the lowest expected cost may also exhibit substantial exposure to unfavorable future conditions, while portfolios that reduce risk may require additional investment and therefore have higher expected costs. As a result, portfolio selection is based on identifying portfolios that achieve an effective balance between these competing objectives.

Within ARIA, this balance is evaluated using a combined cost and risk objective in which mean NPVRR and standard deviation are weighted equally. Conceptually, the model seeks to minimize:

$$\textit{Mean NPVRR} + \textit{Standard Deviation of NPVRR}$$

This formulation reflects an implied one-to-one tradeoff between expected cost and risk. Under this framework, a reduction in portfolio risk is valued equally to an equivalent reduction in expected cost, allowing portfolios to be evaluated on their overall cost-risk performance rather than on cost alone.

It is important to note that this one-to-one weighting is not intended to represent a financial valuation of risk or an estimate of customers' willingness to pay for risk reduction. Rather, it serves as a planning heuristic that allows expected cost and uncertainty to be considered simultaneously within a single evaluation metric. The weighting provides a transparent and consistent framework for screening and comparing portfolios, while the ultimate assessment of portfolio performance also considers the broader cost-risk tradeoffs illustrated by the portfolio frontier and other planning considerations.

In addition to the quantitative objective, portfolio selection is informed through visual examination of the cost-risk frontier. The cost-risk frontier illustrates the relationship between expected cost and risk across the set of candidate portfolios and highlights portfolios that are dominated by alternatives with both lower cost and lower risk. Reviewing the frontier provides additional insight

into the tradeoffs associated with different resource strategies and helps identify portfolios that offer the most favorable balance of cost, risk, and resilience.

By combining comprehensive future evaluation with an explicit cost-risk objective, ARIA supports the selection of portfolios that not only minimize expected costs but also maintains robust performance across the wide range of future conditions considered in the IRP.

H.7.5 Interpretation of Portfolio Risk Metrics

ARIA evaluates portfolios using two (2) primary metrics: mean NPVRR and the standard deviation of NPVRR across all evaluated futures. Together, these metrics provide a concise representation of the expected cost and uncertainty associated with each portfolio.

Mean NPVRR represents the average long-term cost of a portfolio across all future combinations considered within the analysis. This metric reflects the expected customer cost if all modeled futures are considered equally plausible.

Standard deviation measures how much portfolio costs vary across futures and serves as ARIA's primary measure of portfolio risk. Portfolios with higher standard deviations experience larger swings in cost as future conditions change, while portfolios with lower standard deviations tend to produce more consistent outcomes.

Standard deviation was selected as the primary risk metric because it provides a transparent and easily understood measure of uncertainty. It allows all portfolios to be evaluated using a common methodology and directly quantifies the degree to which portfolio costs depend on future market conditions, technology developments, and load growth outcomes.

While alternative risk metrics exist, including worst-case outcomes, percentile-based metrics, and various tail-risk measures, standard deviation provides a practical balance between simplicity and analytical rigor. It captures the overall volatility of portfolio outcomes and enables direct comparison among many candidate portfolios.

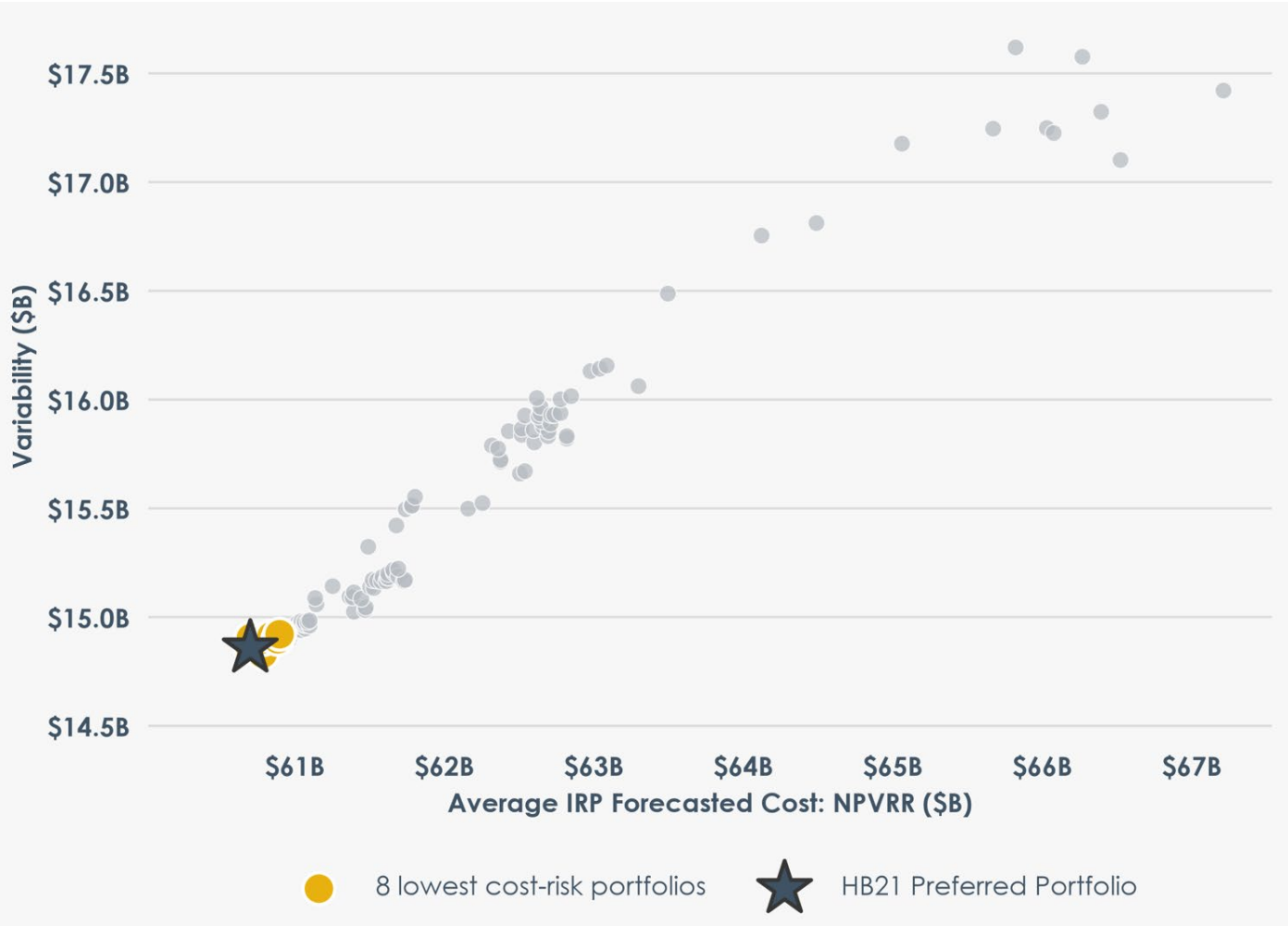
It is important to note that the risk metrics reported by ARIA represent uncertainty in portfolio costs rather than reliability risk. Portfolio reliability is addressed separately through the resource adequacy requirements and reliability constraints incorporated within the portfolio development process. As a result, a portfolio exhibiting lower cost risk is not necessarily more reliable, nor is a portfolio with higher cost risk necessarily less reliable. Rather, the risk metrics described by ARIA should be interpreted as measures of financial exposure to future uncertainty.

H.7.6 Cost-Risk Frontier and Portfolio Comparison

The outputs of ARIA can be visualized using a cost-risk frontier, shown in Figure 182, which provides a graphical representation of the tradeoffs between expected cost and portfolio risk.

Each candidate portfolio can be represented as a point on the frontier, with mean NPVRR plotted on one axis and standard deviation plotted on the other. This allows direct comparison of portfolio performance across both dimensions simultaneously.

Figure 182. Cost & Variability of all 111 GHG Glidepath Portfolios



The frontier highlights portfolios that provide the most efficient balance of cost and risk. Portfolios located on the efficient frontier cannot reduce expected cost without increasing risk, nor can they reduce risk without increasing expected cost, these are the yellow dots on the chart. These portfolios represent the set of best available alternatives available to decision makers.

Conversely, portfolios that exhibit both higher cost and higher risk than another available portfolio are the grey dots up to the top right of the chart. Such portfolios provide neither an economic nor risk-management advantage and are generally excluded from further consideration.

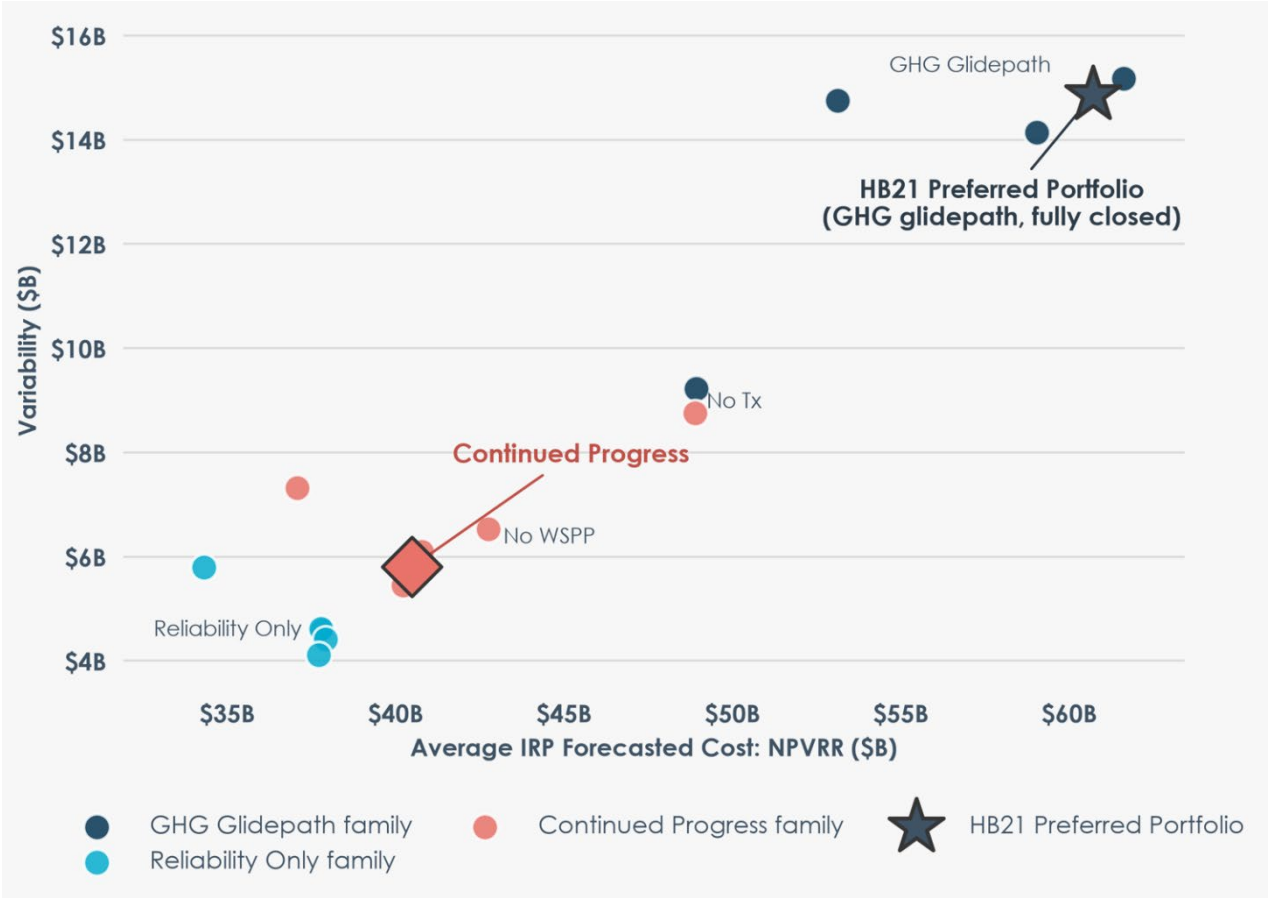
The cost-risk frontier serves as a useful complement to the quantitative portfolio ranking methodology. While the combined cost-risk objective provides a consistent approach for screening portfolios, visual inspection of the frontier provides additional insight into the magnitude of tradeoffs among candidate portfolios.

In some cases, a modest increase in expected cost may result in a significant reduction in risk. In other cases, substantial increases in expected cost may provide only minimal reductions in risk. Examining the frontier helps identify these relationships and supports informed portfolio selection.

The frontier therefore serves not only as a portfolio ranking tool, but also as a means of understanding the value of diversification, risk mitigation, and resilience within the planning process.

This also allows for a more robust comparison of the costs and risks associated with different planning scenarios, shown in Figure 183.

Figure 183. Cost & Variability Across Planning Scenarios



H.7.7 Sources of Portfolio Risk

Portfolio risk arises when future conditions differ from the assumptions under which a portfolio was originally developed. ARIA evaluates this uncertainty by testing each portfolio across a wide range of future combinations, allowing the model to quantify how sensitive a portfolio is to changing conditions.

Several key sources of uncertainty contribute to variations in portfolio costs, including:

- Load and Supply uncertainty.
- Market price uncertainty.
- Technology cost uncertainty.
- Resource development and deployment timing.

- Interactions among multiple uncertain variables.

Load uncertainty affects both the quantity of resources required to serve customers and the amount of energy that must be purchased or generated. Portfolios developed under one set of load assumptions may experience significantly different cost outcomes if actual customer demand evolves differently over time.

Market price uncertainty influences the value of market purchases and sales. Portfolios with greater exposure to wholesale markets may realize substantial benefits when prices move favorably but may also experience higher costs under adverse market conditions.

Technology cost uncertainty affects the long-term economics of new resource additions. Changes in capital costs can alter the relative competitiveness of different resource types and influence the overall cost profile of a portfolio.

These uncertainties do not operate independently. The interaction between load growth, market prices, and technology costs can produce outcomes that are substantially different from the effects of any individual variable considered in isolation. By evaluating all combinations of futures, ARIA captures these interactions and provides a more comprehensive assessment of portfolio risk.

In addition to quantifying overall risk, the ARIA framework can help identify which types of resources provide natural hedges against specific sources of uncertainty. This information can be valuable when comparing portfolios with similar expected costs but different risk profiles.

H.7.8 Limitations and Considerations

ARIA provides a structured and transparent framework for evaluating portfolio cost and risk; however, the results should be interpreted within the context of the model's assumptions and limitations.

The analysis is dependent on the futures included within the study. While the modeled future combinations are intended to represent a broad and diverse range of plausible outcomes, they cannot encompass every possible future condition. Actual market, load, policy, and technology developments may differ from those represented in the analysis.

Similarly, ARIA does not assign probabilities to individual futures. All future combinations are weighted equally within the evaluation framework. This approach avoids introducing subjective estimates regarding the likelihood of specific future conditions, but it also means that the reported results should be interpreted as measures of performance across the modeled future space.

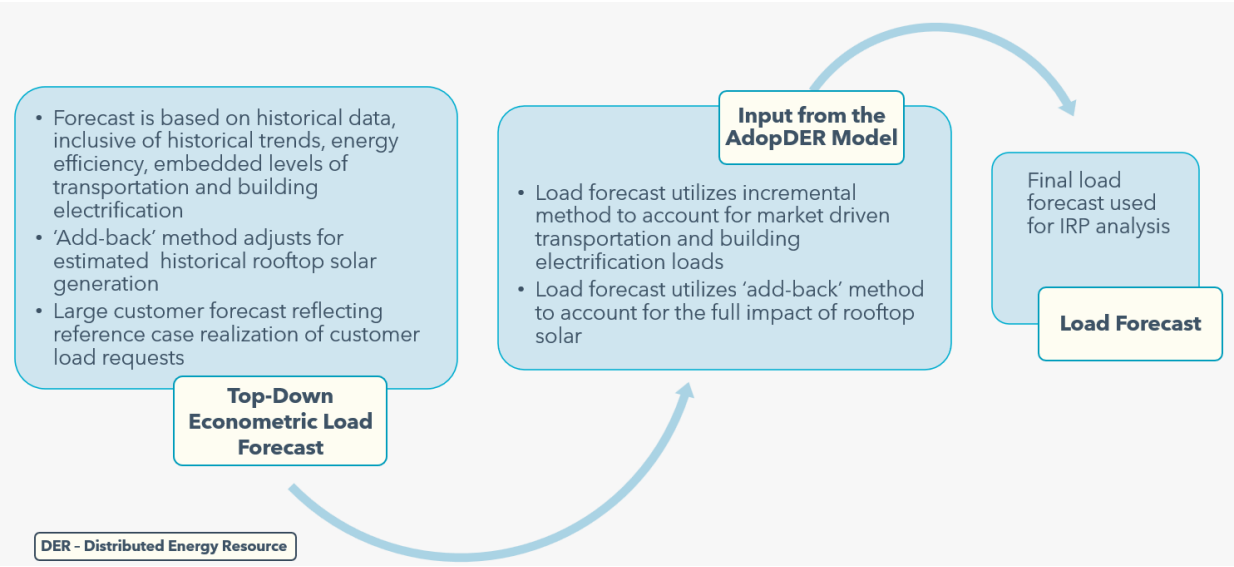
In addition, ARIA focuses specifically on uncertainty in portfolio costs. Other planning considerations—including reliability, resource diversity, operational flexibility, environmental objectives, regulatory requirements, and implementation feasibility—remain important factors in the overall resource planning process and should be considered alongside ARIA results.

For these reasons, ARIA should be viewed as a decision-support tool rather than a standalone portfolio selection mechanism. The model provides valuable insight into the cost-risk characteristics of alternative portfolios, but final planning decisions incorporate both the quantitative results produced by ARIA and broader strategic considerations relevant to PGE's long-term planning objectives.

H.8 Load Forecast Methodology

PGE's load forecast is a compilation of several model outputs. The econometric load forecast is the focus of this appendix. This is a set of models aiming to capture the relationships between PGE's energy deliveries and various structural trends, energy efficiency, and economic drivers. The forecasts of DERs—rooftop solar, and transportation and building electrification—are modeled outside the econometric framework, using the AdopDER model described above in Appendix Section H.1. The impact of rooftop solar on historical energy deliveries is added back to historical data for model estimation and the forecasted impact is removed from the resulting forecast. Electrification impacts are accounted for utilizing an incremental method.

Figure 184. PGE Load Forecast



H.8.1 Refinements Since Last IRP

PGE is continuously refining the load forecast methodology. Model updates included in the 2023 CEP/IRP Update and presented at CEP/IRP Roundtable 24-3 on July 11, 2024:

1. Creation of hourly model specifications which are used alongside the monthly energy deliveries models to estimate expected monthly and seasonal peak demand, create weather year simulations to support resource adequacy analysis, and typical year load shapes to support reference case planning. These models are described below in the Peak Model section.
2. Removal of long-term models and extension of short-term regression models to span full 20-year horizon to allow for integration of large customer load information that spans more than 5 years

Model updates included in the 2026 CEP/IRP and presented in IRP Roundtable 25-7 on October 25, 2025 and IRP Roundtable 26-5 on June 10, 2026:

3. Refinement of the approach taken to account for rooftop solar. This methodological change has also changed the way PGE presents its load forecast in summary materials. In the 2023 CEP/IRP

cycle, the top-down economic regression results were presented independently from the DER forecasts. The integration of rooftop solar to be considered within the econometric model necessitates presenting the final resulting forecast rather than an incremental view.

4. Consideration of recent trends in average residential usage per customer

H.8.1.1 Rooftop Solar Adjustment Methodology

PGE has transitioned to an add back methodology to account for rooftop solar generation in the load forecast. This approach reconstitutes historical energy deliveries to reflect gross customer load prior to the offset from behind-the-meter rooftop solar generation, shown in Equation 3.

Equation 3. Add-back Method

$$(Y_i + E_i) = \beta_0 + \beta_1 X_i$$

Previously, PGE estimated the impact of rooftop solar using an incremental method, which captured only the forward-looking change in rooftop solar generation. Since the 2023 CEP/IRP Update, PGE has developed an enhanced methodology to support an add-back approach. This methodology combines internal data on installed capacity by rate schedule, the pvlib-python photovoltaic performance modeling framework,[269] and hourly local solar irradiance data to estimate historical rooftop solar generation. Table 89 Add Back Rooftop Solar Capacity and Table 90 Add Back Rooftop Solar Energy show rooftop solar estimates which are added back to observed customer usage to create a historical gross-load time series suitable for regression estimation. Forecasts of future rooftop solar adoption and load impacts are derived from PGE's AdopDER model and added to the forecasted gross customer load.

Table 89. Add Back Rooftop Solar Capacity (end of year values, in MW)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Residential	10	16	21	28	36	43	51	60	71	81	100	139	185	223	267
Commercial	13	17	18	20	23	28	32	36	41	45	51	58	64	73	81
Total	23	33	40	47	59	71	83	96	112	126	151	197	249	295	348

[269] Anderson, K., Hansen, C., Holmgren, W., Jensen, A., Mikofski, M., and Driesse, A. (2023), pvlib python: 2023 project update, Journal of Open Source Software, Vol. 8, No. 92, 5994. DOI: 10.21105/joss.05994

Table 90. Add Back Rooftop Solar Energy (Annual MWh, estimated)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Residential	7,356	13,135	19,523	27,232	36,464	41,798	51,323	63,429	71,290	84,688	100,424	131,511	189,244	218,548	275,712
Commercial	10,609	15,062	18,397	21,350	24,835	26,991	32,452	37,077	41,948	47,670	53,683	60,491	70,052	72,939	87,802
Total	17,966	28,197	37,919	48,582	61,299	68,790	83,775	100,506	113,238	132,358	154,108	192,002	259,296	291,487	363,515

This approach is more appropriate than the more limited incremental method given the unique seasonal shape of rooftop solar generation. The "add-back" method is also more appropriate than the explanatory variable method because it does not rely on a statistical estimation of the relationship between the solar generation time series and usage data. The "add-back" approach assumes that the relationship is known, which is true. Rooftop solar generation offsets electricity usage at the customer meter. The "add-back" method then adjusts to account for the volume of rooftop generation directly. Capturing the entirety of rooftop solar generation, rather than just the incremental solar from prior period, allows for a more robust reflection of the seasonal and diurnal shape of rooftop solar on PGE's load. In addition, the 'add-back' approach, which adjusts the historical usage to account for demand that was offset by rooftop solar generation, allows more accurate estimation of relationships between usage and other model drivers such as heating and cooling degree days and energy efficiency.

The add-back methodology provides a more accurate representation of rooftop solar impacts than the incremental approach in two (2) ways. Using the reconstituted historical gross load provides more robust estimation of underlying relationships between electricity usage and other forecast drivers, such as heating and cooling degree days, energy efficiency, and economic factors. In the forecast period, including the full magnitude of load associated with rooftop solar generation enables the forecast to capture the seasonal and diurnal generation profile of rooftop solar resources.

H.8.1.2 Residential Model Specifications

Residential UPC shifted dramatically in 2025 for both the cooling and heating seasons as compared to prior periods. Weather adjusted UPC for July-September of 2025 increased by 3.6% year-over-year. In the following months, October-December, weather adjusted UPC decreased by 3.7% year-over-year. This trend of decreased winter usage continued into 2026, with weather adjusted January-March usage decreasing by 4.7%.

Model residuals represent the difference between the predicted values, given actual values of historical input drivers, and the observed historical data, and are frequently used to assess model fit and normality. Figure 185, Figure 186, and Figure 187 below show the model residuals associated with the September 2025 load forecast specifications presented as a percentage of observed value. Recent months show clear divergence from the prior model structure, as indicated by the large percentages deviation between predicted and observed data.

Figure 185. Single Family UPC Model Residual, September 2025 Specifications

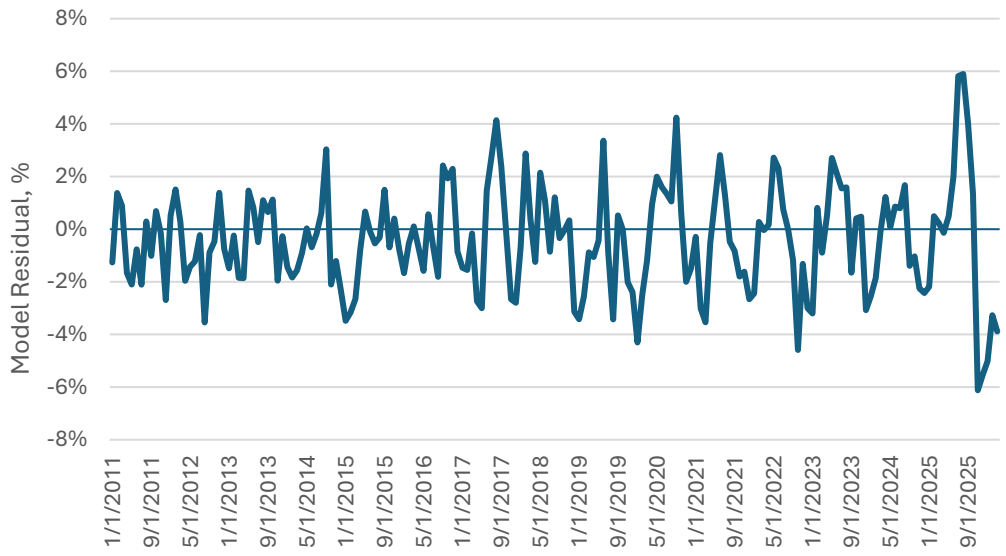


Figure 186. Multi Family UPC Model Residual, September 2025 Specifications

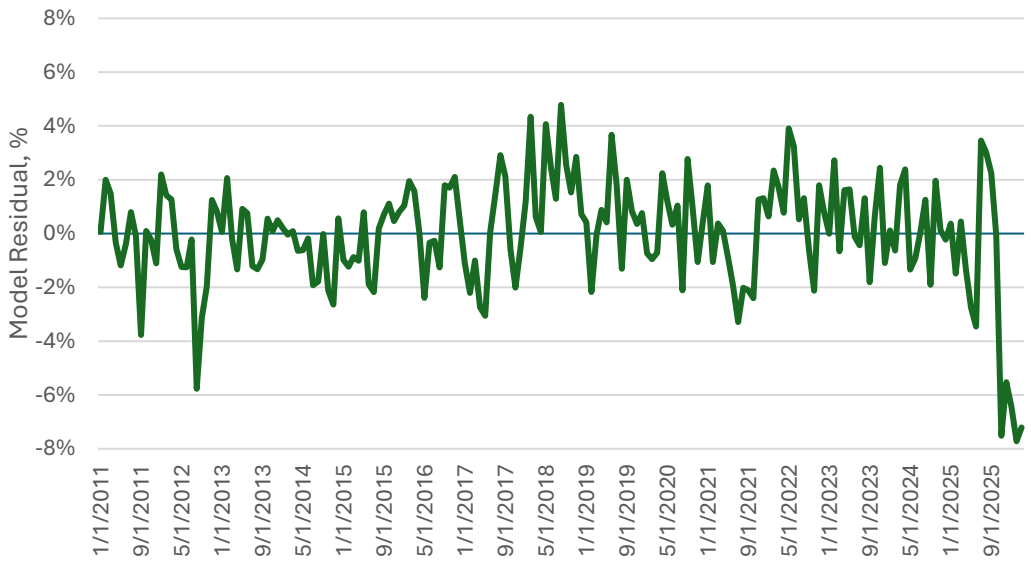
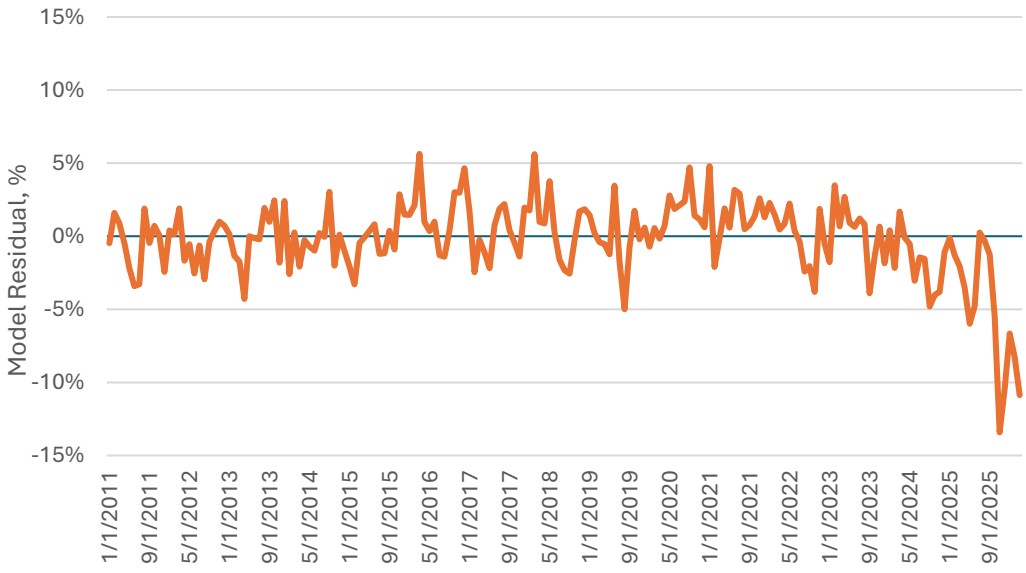


Figure 187. Manufactured Home UPC Model Residual, September 2025 Specifications



Although seasonal fluctuations were present across all dwelling types, when looking at the data by dwelling type, it appears single-family customers (Figure 185) were the primary drivers of the increase during the cooling season, while multi-family and manufactured home customers Figure 186 and Figure 187) drove the decrease during the heating season.

When developing the regression models, a full review of residuals and model fit is performed with each forecast update. As shown above, when actual usage and temperature data through March 2026 was added to the estimation period for the prior model specifications, the fit of all residential models deteriorated. Summer usage was underestimated while winter usage was overestimated. Given the magnitude and persistence of shift in the historical data and the decreased model performance, PGE chose to update residential model specifications to ensure the load forecast captures these trends. Three updates were made:

1. The time frame used to estimate the residential models was shortened from fifteen years to ten years, or beginning in 2016, to focus on more recent usage patterns.
2. A trend indicator variable was added to the single-family model to account for increased AC penetration. This variable is only considered in the cooling season.
3. The multifamily and manufactured homes models were adjusted to account for decreased heating demand. The mechanism for this adjustment was to add a control variable, or step change, interacted with Heating Degree Days beginning in February of 2025 and April of 2025 respectively.

These methodology updates do not result in the entirety of the recent changes in usage being carried forward throughout the rest of 2026 and into 2027, as illustrated below. This is considered a conservative approach given the uncertainty in the persistence of these changes.

H.8.2 Energy Model

H.8.2.1 Residential Model

To forecast residential usage, PGE creates three sets of use-per-customer (UPC) and customer new connect models by dwelling type, (single family, multifamily and manufactured homes) as well as one model for the other category. Dwelling type forecast are created by combing UPC and new connects forecast, as presented in Equation 4, Equation 5, and Equation 6 present variable options for use-per-customer and new connect models.

Equation 4. Residential Energy Deliveries

$$kWh_{res} = UPC_{res} * CC_{res}$$

Where:

UPC = Use-per-customer

CC = Customer count

Equation 5. Residential Use-Per-Customer

$$UPC_{dwelling,t} = fn\,(HDD, CDD, wind, energy\ efficiency, month, COVID\ indicator, Control\ Indicators\,) + \varepsilon_t$$

Where:

HDD = Heating degree day

CDD= Cooling degree day

Wind = Average monthly wind speed

Energy Efficiency = Residential energy efficiency saving provided by the Energy Trust of Oregon

COVID Indicator = Indicator variable between 0 and 1

Control Indicators = Steps and spikes to adjust for changes in data trends, Indicator variable between 0 and 1

Month = Monthly Indicators

ε_t= error term

Equation 6. Residential New Connects

$$New\ Connects_{dwelling,t} = fn\left(\begin{matrix}Building\ Permits, month, Oregon\ Construction\ Employment,\\ control\ indicators\end{matrix}\right) + \varepsilon_t$$

Where:

Building Permits dwelling = Oregon building permits dwelling

Oregon Construction Employment = Employment of Oregon construction

Control Indicators = Steps and spikes to adjust for changes in data trends, Indicator variable between 0 and 1

Month = Monthly Indicators

ε_t= error term

H.8.2.2 Commercial and Industrial Model

To forecast commercial and non-large customers industrial usage, PGE's regression models' energy deliveries are grouped into five rate schedule-based models: Schedule 32, Schedule 38, Schedule 83, Schedule 85, and Schedule 89. These regression models exclude those customers that are forecasted individually in the individual large customer forecast which includes several Schedule 89 customers, all Schedule 90 and Schedule 96 customers.

The commercial energy deliveries model, shown in Equation 7, present variable options for commercial models.

Equation 7. Commercial Energy Deliveries

$$kWh_{rate\ schedule,t} = fn\ (HDD, CDD, energy\ efficiency, employment, month,\\ control\ indicators) + \varepsilon_t$$

Where:

HDD = Heating degree day

CDD= Cooling degree day

Energy Efficiency = Residential energy efficiency saving provided by the Energy Trust of Oregon

Employment = Oregon nonfarm employment

Month = Monthly Indicators

Control Indicators = Steps and spikes to adjust for changes in data trends, Indicator variable between 0 and 1

ε_t = error term

H.8.2.3 Model Development and Evaluation

A series of testing steps are used to develop long-term forecast models. This testing includes a univariate review of the underlying structure of the energy deliveries time series; an examination of

the relationship between energy deliveries to drivers, including weather variables; and the testing of alternative model structures, including naïve and "automatic" ARMA. The model fit statistics, coefficients, and residuals are reviewed to compare and select alternate models.

Univariate analysis. Univariate analysis of historical sector-level time series is conducted to identify trends, seasonality, cycles, breaks, and outliers. The first step is to inspect the data series visually. Then the autocorrelation of the series is reviewed, and statistical tests such as the Augmented Dickey Fuller (ADF) and Kwiatkowski, Phillips, Schmidt, and Shin (KPSS) tests are used to assess the underlying structure of the data.

Automated ARMA selection: An automated process is used to select ARMA model parameters instead of manually reviewing model output including the model correlogram and Durbin-Watson statistic. PGE utilizes SAS software automated selection of ARMA[270] parameters and SAS software to estimate forecasts and compile results. PGE utilizes the PROC ARIMA: IDENTIFY and SCAN function to select ARMA parameters and the models are then run using PROC ARIMA.

Weather responsiveness. Scatter plots and testing in the regression models are used to determine the appropriate HDD and CDD variables for inclusion in each model. Figure 188, Figure 189, Figure 190, and Figure 191 show the weather responsiveness for four examples including, single family use-per-customer solar adjusted, multifamily use-per-customer, rate schedule 32 solar adjusted, and rate schedule 89.

Figure 188. Weather Scatter Plot Examples A

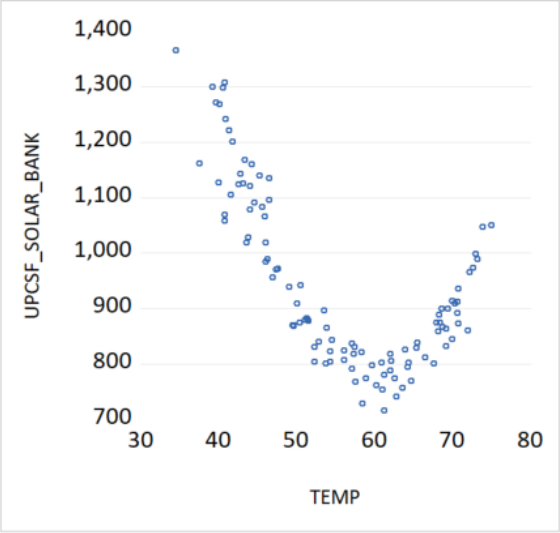
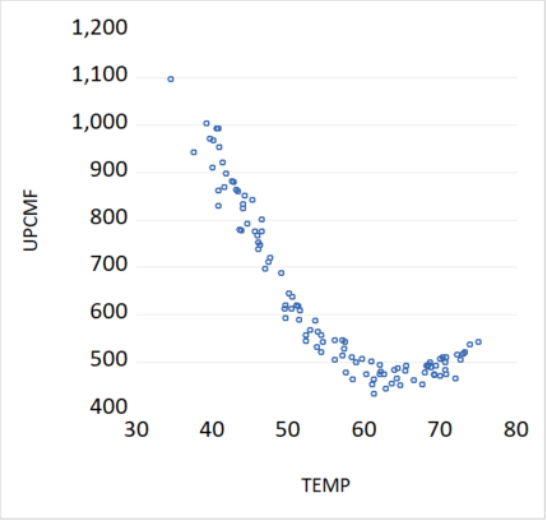


Figure 189. Weather Scatter Plot Examples B



[270] PGE does not utilize differencing within the ARIMA function. The SAS procedure used is PROC.ARIMA, however the model options are defined such that only ARMA terms are considered.

Figure 190. Weather Scatter Plot Examples C

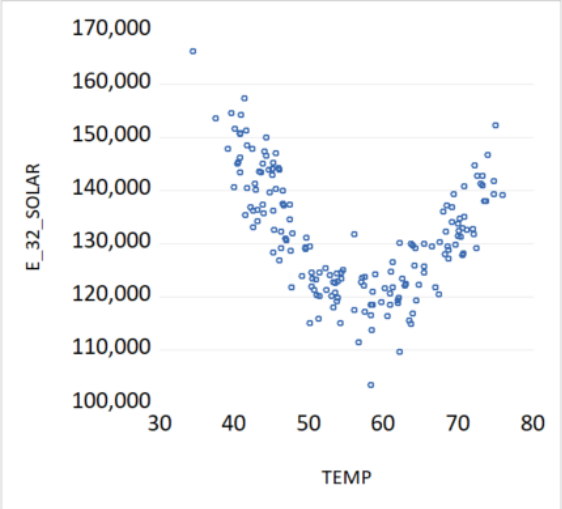
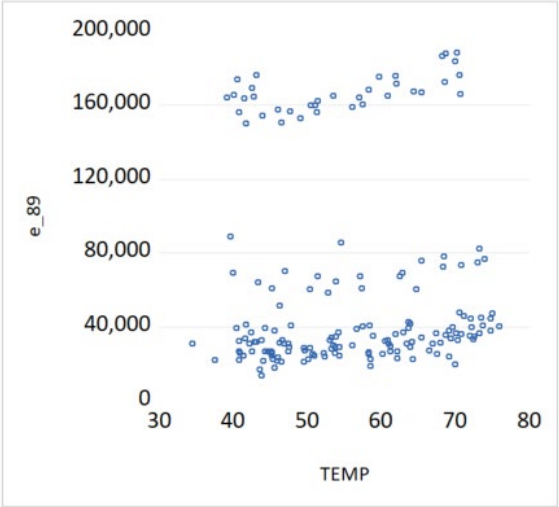


Figure 191. Weather Scatter Plot Examples D



The scatter in (a) follows a relatively tight "U" shape, indicating that single family residential energy usage increases as the average temperature falls under 55˚F and as the average temperature is higher than 65˚F, additionally there is a chance in slope when temperature is above 70˚F. This implies using an HDD variable calculated from a 55 base and a CDD variable with a 65˚F base and an additional CDD variable with a 70 base. In (b), multifamily increase as the average temperature falls under 60˚F, additionally there is a chance in slope when temperature is below 50˚F and when the average temperature is higher than 60˚F. In (c), rate schedule 32 increase as the average temperature falls under 55˚F and when the average temperature is higher than 60˚F. In (d) the broad scatter implies that energy deliveries to rate schedule 89 have no significant weather dependence.

1. Residual review. PGE reviews the autocorrelation and normality of residuals in the models for any alternative model structures considered. Ideally, residuals are white noise, meaning they are uncorrelated, have a mean of 0, have constant variance, and are normally distributed. The extent to which residuals of a regression statistically differ from white noise indicates the potential to improve the model specification. Residuals that are meaningfully correlated might lead to the addition of autoregressive or moving average terms to the model or re-visiting the regression model specification.

2. Alternate forecasts and out-of-sample testing. PGE reviews a variety of alternate model specifications for each of the forecast groups. Testing includes: 1) models using a variety of economic drivers, as well as those with no economic driver; 2) models with and without monthly indicator variables; and 3) models using a variety of data transformations. As part of the standardization of the model evaluation and to benchmark against the most simplistic models, PGE also tests naïve and seasonally naïve forecasts. Out-of-sample testing, which uses a training period to estimate the model and a testing period to evaluate model performance, was included as a part of PGE's testing process in the 2019 IRP Load Forecasting Appendix. PGE did not perform out-of-sample testing because of the dramatic but short-lived period of impact for

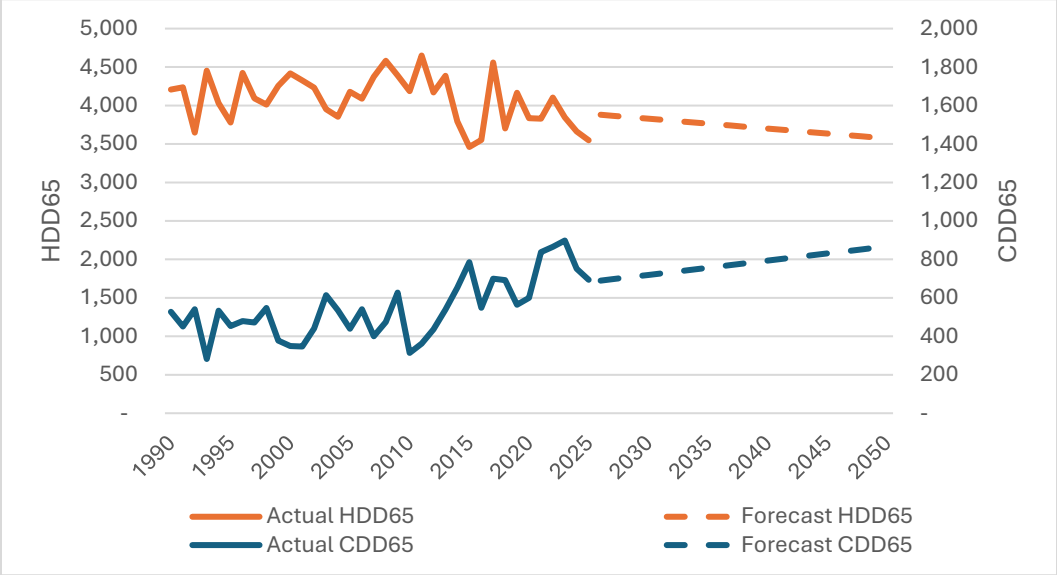
the COVID-19 indicator variable did not allow for a long enough period to reflect useful testing and the inclusion of the heating degree step interaction used for multifamily and manufactured home models.

H.8.3 Energy Model Inputs

H.8.3.1 Normal Weather Assumption

A "normal" weather year is assumed as an input to the load forecast rather than a weather forecast. Weather variability that differs from the normal weather assumption is expected. The intention is to use an unbiased weather assumption such that the actual weather is warmer or cooler than normal 50% of the time. PGE uses a trend to create the forward-looking normal weather assumption that reflects the gradually warming climate. The methodological approach continues the trend observed since 1975, using data since 1941 to "hinge" the initial point of that trend.[271] Figure 192 shows historical actual and forward-looking normal for heating and cooling degree days (HDD and CDD)[272] using this methodology.

Figure 192. Normal Weather Expectations in Terms of Heating Degree Days and Cooling Degree Days



H.8.3.2 Energy Efficiency

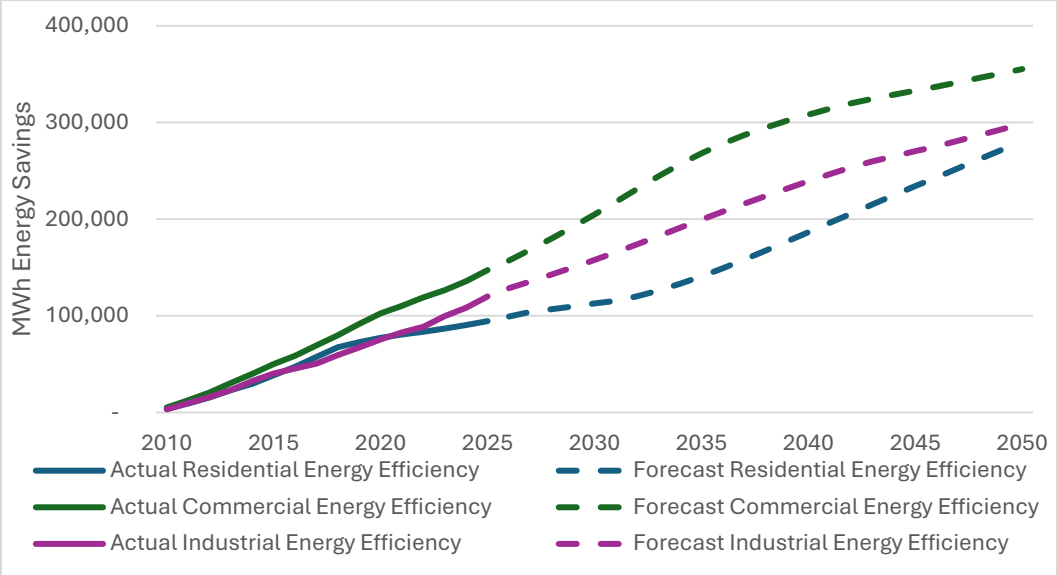
To account for energy efficiency programs, implemented by Energy Trust of Oregon, estimated savings are included as a righthand side variable in the residential and commercial rate schedule regression models. PGE uses the Energy Trust of Oregon's forecast of future savings as an input assumption. The projected energy savings from 2026 to 2050 are 4.5%, 3.6%, and 3.7% for

[271] Livezey, Robert E., et al. "Estimation and extrapolation of climate normals and climatic trends." Journal of Applied Meteorology and Climatology 46.11 (2007): 1759-1776. https://journals.ametsoc.org/doi/pdf/10.1175/2007JAMC1666.1

[272] Heating and cooling degree days (HDD and CDD) are the number of degrees that a day's temperature deviates from the temperature set point. For heating degree days, the measurement represents the extent to which a building would need to be heated to reach the temperature set point, and for cooling degree days, the measurement represents the extent to which a building would need to be cooled to reach the temperature set point. For these regressions with monthly data, HDD and CDD are summed for all days in the month. As an example, on a day with an average temperature of 75° F, HDD65 = 0 and CDD65 = 75 - 65 = 10.

residential, commercial and industrial respectively. Figure 193 shows the historical actual and forecasted levels of savings by class.

Figure 193. Energy Efficiency by Customer Class

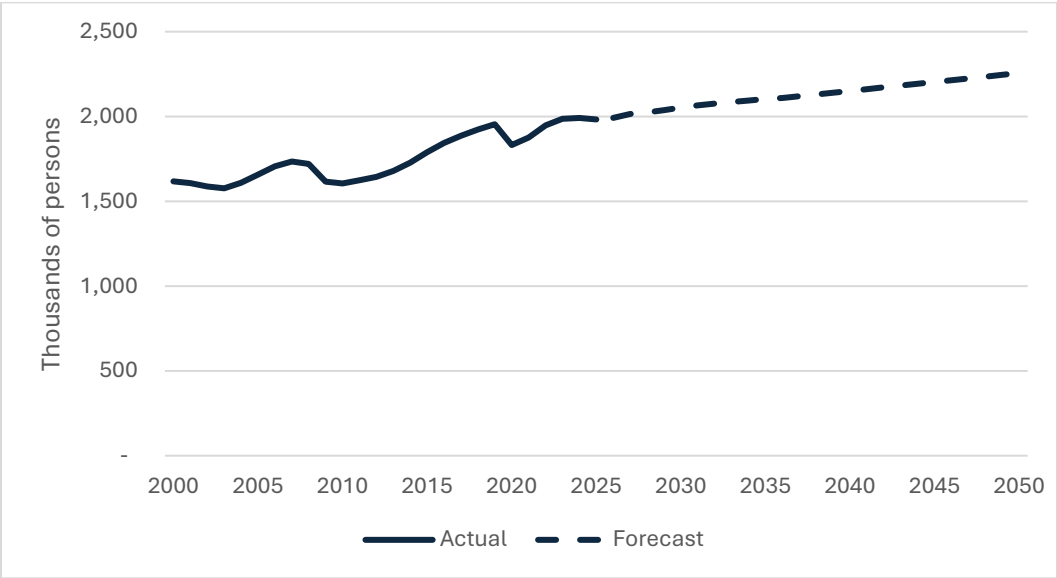


H.8.4 Macroeconomic Drivers

H.8.4.1 Oregon Total Non-Farm Employment

The level of employment in Oregon is the economic driver of PGE's commercial and industrial energy deliveries forecast. PGE uses the Oregon Office of Economic Analysis's forecast of total non-farm employment, extended to 2050. The projected average annual growth rate from 2026 to 2050 is 0.5%. Figure 194 shows the historical and forecasted levels of Total Non-Farm Employment.

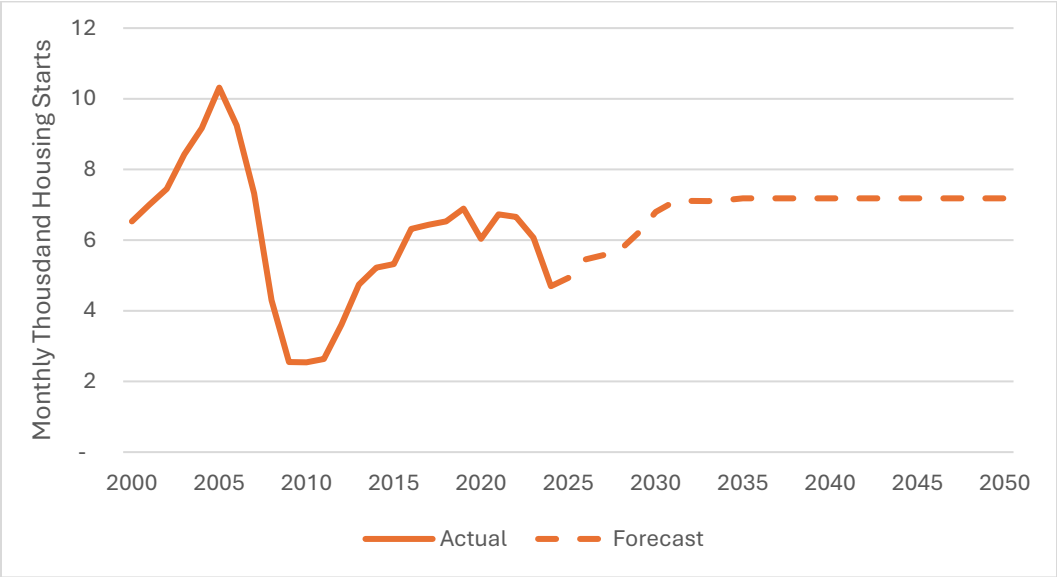
Figure 194. Oregon's Total Non-Farm Employment



H.8.4.2 Housing Starts

To forecast new connects PGE utilizes building permits. As there is no state level building permit forecast, PGE utilizes Oregon housing starts to forecast building permits. PGE uses the Oregon Office of Economic Analysis's forecast of housing starts, extended to 2050. The projected average annual growth rate from 2026 to 2050 is 1.6%. Figure 195 shows the historical and forecasted levels of Oregon Housing Starts.

Figure 195. Oregon's Housing Starts



H.8.4.3 Large Customer Forecast

PGE's energy deliveries forecast includes individual customer forecasts for a subset of about 30 of its largest customers. These customers tend to be large or rapidly growing; however, smaller customers may be included simply based on legacy of historical loads that fit these criteria. PGE's process for developing its large customer forecast is based on review of monthly historical data, forecasted economic conditions, quarterly meetings with PGE's key account managers, and assessment of risks associated with load ramping cadence and total anticipated loading which includes considerations of relevant contracts with customers.

H.8.5 Peak Model

In 2024, PGE developed an hourly methodology for use in the 2023 CEP/IRP Update. The hourly models use load research data from the most recent five years available, in this case 2021-2025, as training data to create three sets of 24 hourly models that describe load behavior for the three aggregated customer groups: residential, commercial, and industrial. To be consistent with the monthly energy model, the "add-back" method is used to account for rooftop solar generation; the historical series is reconstituted to reflect gross load and the load impact of rooftop solar generation is subtracted from the forecast.

The hourly models include independent variables to capture weather, monthly indicator variables, extreme events, trends, and day of the week. The variable selection for each of the 72 models is automated using SAS function proc glmselect. Equation 8 presents variables included in the selection process.

To estimate a 1-in-2 peak, PGE relies on the hourly framework in conjunction with weather year simulations. The hourly model is run using 15 years of historical weather data (2011-2025). To capture the impact of day of week, each weather year is paired with each possible day-of-week start configuration, resulting in a total of 105 simulations for each forecast year.

The hourly model is intended to complement, rather than replace, the monthly energy deliveries model. Each simulation is scaled by customer class to align with the corresponding monthly energy forecast ensuring consistency with the growth drivers captured in the monthly econometric models.

For each simulation, the maximum hourly load is identified within each month. Monthly peak demand is then calculated as the average of these monthly maximum loads across all 105 simulations. This approach produces a weather-normalized estimate of monthly peak demand that is consistent with the underlying energy forecast.

Equation 8. Peak Demand

$$MW_{class,h,date} = \beta_1 + \beta_2 CDD + \beta_3 CDD\ build\ up + \beta_4 HDD\ WC + \beta_5 HDD\ build\ up + \beta_6 CDD * Season + \beta_6 HDD\ WC * Season + \beta_7 Season + \beta_7 Daylight + \beta_7 wind + \beta_7 Daylight + \beta_7 Trend + \sum_{k=0}^{11} \beta_k\ Month_k + \sum_{k=0}^{6} \beta_k\ Day\ of\ Week_k + \beta_{26} ice\ event + \beta_{27} heat\ dome + \beta_{27} smoke\ event + \beta_{27} holidays + \varepsilon_t$$

Where:

MW = Hourly usage data by customer class with rooftop solar added back

CDD = CDD with multiple set points for each hour

CDD build up = CDD with multiple set points, average multiple lagged CDD to account for heat build up

HDD WC = HDD including wind chill with multiple set points for each hour

HDD build up = HDD with multiple set points, average multiple lagged CDD to account for heat build up

WIND = Average hourly wind speed

Trend = Monthly trend to account for customer growth and energy efficiency

Month = Monthly Indicators

Day of Week = Weekday indicators

Ice event = indicator variable to account for large scale ice storm

Heat dome = indicator variable to account for 2021 heat dome

ε_t = error term

H.8.6 Load Scenarios

H.8.6.1 High and Low Scenarios

High and low load forecasts are created to account for different economic futures. The health of Oregon's economy impacts PGE's load growth, with residential driven by customer growth and commercial driven by employment. In addition to the customer growth and employment scenarios, PGE accounted for different large customer growth futures. Table 91 presents high and low assumptions and 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.

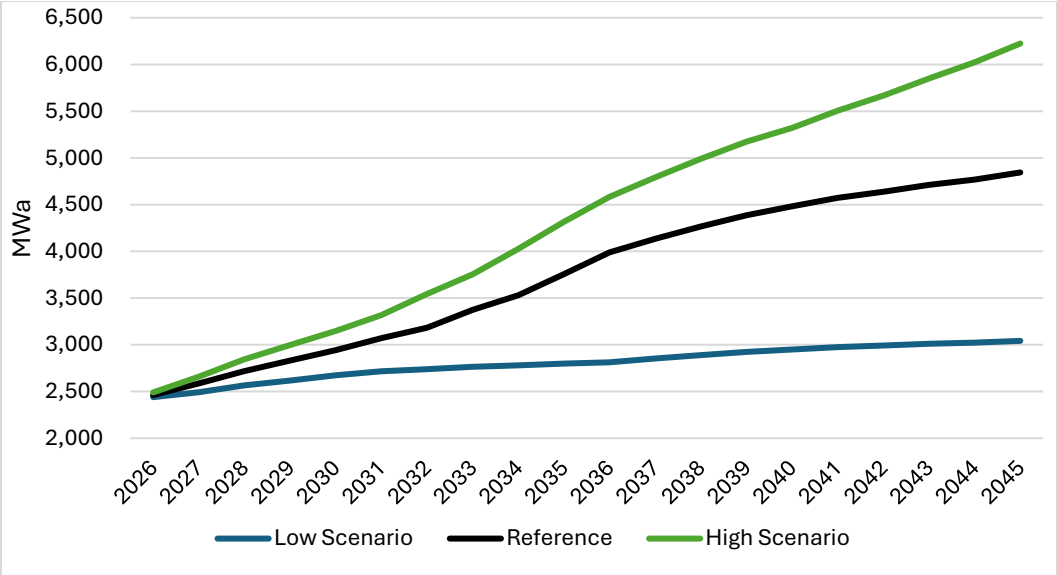
Strong demand for industrial load service increases the inherent uncertainty of the load forecast. PGE has received service requests from many large industrial customers whose requested load service is not included in the Reference Case load forecast. Exclusion of these industrial requests is supported by judgement on the maturity of projects. The use of scenario analysis allows for consideration of large customer projects that vary from the reference case.

Adoption of distributed energy resources (DERs) are a large driver of energy futures. To account for adoption scenarios, AdopDER scenarios are layered on top of the high and low scenarios, as presented in Table 91. High solar adoption is used for the low scenario and vice versa as rooftop solar installation reduces usage. Resulting forecasts are presented in Figure 196.

Table 91. High, Low, and Reference Scenario Assumption

	Low	Reference	High
Customer Count (AAGR)	0.4%	1.0%	1.7%
Oregon Nonfarm Employment (AAGR)	0.4%	0.55%	0.9%
Large Customer Assumptions	Datacenter of 600 MW in 2030 and 800 MW by 2041. Modest growth in semiconductor.	Datacenter 400 MW doubles by 2030 and is 2 GW by 2037. Modest growth in semiconductor.	Datacenter to 2.0 GW by 2035 and growth cycle continues into the 2040s. Semiconductor grows at a moderate pace, adding 100 MW by 2030.
Rooftop Solar (AdopDER Scenario)	High adoption	Reference adoption	Low adoption
Building Electrification (AdopDER Scenario)	Low adoption	Reference adoption	High adoption
Transportation Electrification (AdopDER Scenario)	Low adoption	Low adoption	Reference adoption
Total Growth Rate	**1.1%**	**3.6%**	**4.9%**

Figure 196. High, Low, and Reference Forecast



Previously, PGE presented uncertainty using the output statistics of the regression models described previously, based on model uncertainty and coefficient uncertainty. Since the 2023 CEP/IRP, a high and low scenario-based approach was deemed to be a better representation given the high uncertainty around forecast futures, specifically due to the uncertainty around large load which is not forecasted using regression models.

H.8.6.2 Core Load Growth Only Scenario

To provide transparency into the drivers of PGE's resource need, analysis was performed to disaggregate large industrial load from PGE's forecast. As described in Section 3.1.2, semiconductor and datacenter loads are responsible for significant increases in PGE's forecast. To isolate the impact of growth from large industrial load, PGE focuses on the large customer forecast, holding all customers expected to receive service on PGE's Tariff Schedule 96 - Datacenter Standard Service at current load levels. 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 datacenter customer projects thereafter based on PGE's May 2026 Reference case Load Forecast.

H.8.6.3 Weather Simulation

The single most important driver of load variability is the weather. Residential and small commercial loads are particularly sensitive to the weather due to heating and cooling needs. Weather is known to be highly variable from one year to the next. PGE addresses the stochastic risk in the load forecast associated with weather, analyzing 30 years of weather variability run through the hourly model discussed above.

H.8.7 Results

H.8.7.1 Energy Load Forecast

Forecasts for average energy, presented in MWa, including the impacts of Distributed Energy Resources (DERs) are presented below in Table 92 though Table 95. These load forecasts do not include long-term direct access loads, consistent with Guideline 9.[273] This section provides load forecasts for scenarios: low, reference, high and core growth only load presented by customer class: residential, commercial, and industrial.

[273] Order No. 07-002 at 19, see Guideline 9, as amended by Order No. 07-047 at Appendix A, p.6

Table 92. PGE Load With Reference Growth Conditions, MWa

Year	Residential	Commercial	Industrial	Total
2027	925	771	834	2,530
2028	935	772	951	2,659
2029	949	769	1,052	2,770
2030	965	767	1,147	2,880
2031	985	765	1,254	3,004
2032	1,006	762	1,345	3,113
2033	1,027	760	1,515	3,301
2034	1,048	759	1,647	3,454
2035	1,070	758	1,846	3,675
2036	1,092	759	2,052	3,903
2037	1,113	761	2,170	4,045
2038	1,134	764	2,275	4,174
2039	1,154	768	2,370	4,292
2040	1,174	772	2,440	4,385
2041	1,192	776	2,506	4,474
2042	1,210	781	2,547	4,538
2043	1,226	786	2,598	4,610
2044	1,242	791	2,632	4,665
2045	1,255	796	2,690	4,740
Average annual growth rate	**1.7%**	**0.2%**	**6.8%**	**3.6%**

Table 93. PGE System Load With Low Growth Conditions, MWa

Year	Residential	Commercial	Industrial	Total
2027	919	731	789	2,439
2028	924	730	857	2,511
2029	931	736	893	2,560
2030	941	747	928	2,616
2031	952	748	956	2,657
2032	964	742	974	2,680
2033	975	737	992	2,704
2034	987	732	1,001	2,720
2035	999	729	1,010	2,739
2036	1,010	727	1,014	2,751
2037	1,021	725	1,046	2,792
2038	1,030	725	1,073	2,828
2039	1,039	725	1,097	2,861
2040	1,046	725	1,114	2,885
2041	1,053	725	1,133	2,911
2042	1,058	726	1,144	2,928
2043	1,062	728	1,157	2,946
2044	1,064	729	1,165	2,958
2045	1,064	730	1,182	2,976
Average annual growth rate	**0.8%**	**0.0%**	**2.3%**	**1.1%**

Table 94. PGE System Load With High Growth Conditions, MWa

Year	Residential	Commercial	Industrial	Total
2027	936	780	884	2,600
2028	957	785	1,041	2,783
2029	981	786	1,166	2,933
2030	1,010	788	1,282	3,081
2031	1,045	789	1,411	3,246
2032	1,082	791	1,594	3,467
2033	1,120	795	1,758	3,673
2034	1,160	800	1,980	3,940
2035	1,200	807	2,216	4,222
2036	1,239	814	2,430	4,484
2037	1,278	823	2,588	4,689
2038	1,316	834	2,735	4,884
2039	1,353	845	2,864	5,062
2040	1,390	854	2,963	5,207
2041	1,426	865	3,096	5,387
2042	1,461	876	3,209	5,546
2043	1,496	886	3,344	5,725
2044	1,529	895	3,470	5,894
2045	1,561	904	3,626	6,091
Average annual growth rate	**2.9%**	**0.8%**	**8.2%**	**4.9%**

Table 95. PGE System Load With Core Growth Only Load Conditions, MWa

Year	Residential	Commercial	Industrial	Total
2027	925	771	808	2,504
2028	935	772	851	2,558
2029	949	769	869	2,587
2030	965	767	876	2,608
2031	985	764	894	2,644
2032	1,006	762	893	2,660
2033	1,027	759	899	2,685
2034	1,048	758	900	2,706
2035	1,070	758	900	2,728
2036	1,092	758	898	2,748
2037	1,113	760	903	2,777
2038	1,134	764	908	2,805
2039	1,154	767	911	2,832
2040	1,174	771	912	2,857
2041	1,192	775	919	2,887
2042	1,210	780	924	2,913
2043	1,226	785	929	2,940
2044	1,242	790	931	2,963
2045	1,255	794	938	2,988
Average annual growth rate	**1.8%**	**0.2%**	**1.9%**	**1.1%**

H.8.7.2 Peak Load Forecast

Table 96 provides the seasonal peak loads for each year and Need Future.[274]

[274] As mentioned previously, the load forecasts in the section do not include long-term direct access loads.

Table 96. Peak Load Forecast by Need Future and Season, MW

Year	Low Need		Reference Need		High Need		Core Growth Only Load	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
2026	4,162	3,551	4,192	3,571	4,233	3,599	4,192	3,571
2027	4,199	3,605	4,329	3,708	4,444	3,795	4,279	3,688
2028	4,280	3,662	4,484	3,831	4,676	3,981	4,356	3,729
2029	4,347	3,726	4,625	3,959	4,872	4,151	4,403	3,775
2030	4,422	3,789	4,763	4,079	5,078	4,320	4,443	3,808
2031	4,474	3,842	4,928	4,217	5,292	4,529	4,505	3,857
2032	4,505	3,864	5,057	4,350	5,581	4,755	4,540	3,882
2033	4,531	3,912	5,293	4,546	5,847	5,019	4,581	3,934
2034	4,554	3,938	5,489	4,736	6,171	5,320	4,617	3,975
2035	4,578	3,972	5,748	4,982	6,516	5,636	4,655	4,020
2036	4,596	3,993	6,023	5,235	6,836	5,930	4,692	4,060
2037	4,642	4,062	6,190	5,413	7,085	6,187	4,735	4,121
2038	4,692	4,120	6,359	5,577	7,343	6,429	4,788	4,178
2039	4,732	4,174	6,508	5,728	7,575	6,652	4,834	4,234
2040	4,770	4,213	6,637	5,853	7,783	6,839	4,880	4,283
2041	4,801	4,270	6,747	5,977	8,014	7,068	4,927	4,348
2042	4,824	4,314	6,835	6,078	8,226	7,279	4,974	4,409
2043	4,854	4,359	6,935	6,185	8,467	7,505	5,022	4,468
2044	4,881	4,393	7,024	6,275	8,707	7,719	5,070	4,519
2045	4,911	4,440	7,121	6,380	8,957	7,954	5,115	4,576
Annual average growth rate	**0.9%**	**1.2%**	**2.8%**	**3.1%**	**4.0%**	**4.3%**	**1.1%**	**1.3%**

H.8.7.3 Net System Load

Net System Load includes both cost-of-service supply customers and direct access customers. While Net System Load is not used in the IRP need assessments or portfolio analysis, the information in this section is provided for reference as it reflects the level of disaggregation at which the load forecast analysis occurs.

Table 97, Table 98, Table 99, and Table 100 provide the reference, low, high, and core load growth only econometric load forecasts for Net System Load in MWa by class.

Table 97. Net System Load with Reference Growth Conditions, MWa

Year	Residential	Commercial	Industrial	Total
2027	925	814	1,066	2,804
2028	935	809	1,158	2,902
2029	949	806	1,263	3,017
2030	965	803	1,360	3,128
2031	985	801	1,471	3,257
2032	1,006	798	1,564	3,367
2033	1,027	795	1,736	3,557
2034	1,048	794	1,870	3,711
2035	1,070	793	2,070	3,933
2036	1,092	794	2,275	4,161
2037	1,113	796	2,394	4,303
2038	1,134	799	2,499	4,432
2039	1,154	803	2,594	4,551
2040	1,174	806	2,664	4,644
2041	1,192	811	2,732	4,735
2042	1,210	815	2,774	4,799
2043	1,226	820	2,825	4,872
2044	1,242	825	2,860	4,927
2045	1,255	830	2,919	5,004
Average annual growth rate	**1.7%**	**0.1%**	**5.8%**	**3.3%**

Table 98. Net System Load with Low Growth Conditions, MWa

Year	Residential	Commercial	Industrial	Total
2027	919	772	1,020	2,710
2028	924	766	1,062	2,751
2029	931	771	1,102	2,805
2030	941	783	1,140	2,863
2031	952	784	1,172	2,908
2032	964	777	1,192	2,933
2033	975	771	1,213	2,959
2034	987	767	1,222	2,975
2035	999	763	1,232	2,994
2036	1,010	760	1,235	3,006
2037	1,021	759	1,267	3,047
2038	1,030	758	1,295	3,083
2039	1,039	758	1,320	3,116
2040	1,046	758	1,337	3,141
2041	1,053	758	1,357	3,167
2042	1,058	759	1,368	3,185
2043	1,062	760	1,382	3,204
2044	1,064	761	1,391	3,216
2045	1,064	762	1,409	3,235
Average annual growth rate	**0.8%**	**-0.1%**	**1.8%**	**1.0%**

Table 99. Net System Load with High Growth Conditions, MWa

Year	Residential	Commercial	Industrial	Total
2027	936	823	1,117	2,876
2028	957	823	1,248	3,027
2029	981	823	1,377	3,181
2030	1,010	825	1,495	3,331
2031	1,045	826	1,628	3,500
2032	1,082	828	1,813	3,723
2033	1,120	832	1,980	3,932
2034	1,160	836	2,204	4,200
2035	1,200	844	2,441	4,485
2036	1,239	851	2,656	4,746
2037	1,278	860	2,815	4,952
2038	1,316	871	2,962	5,148
2039	1,353	882	3,093	5,328
2040	1,390	892	3,192	5,473
2041	1,426	903	3,326	5,655
2042	1,461	913	3,440	5,815
2043	1,496	924	3,577	5,996
2044	1,529	933	3,703	6,166
2045	1,561	943	3,861	6,364
Average annual growth rate	**2.9%**	**0.8%**	**7.2%**	**4.5%**

Table 100. Net System Load with Core Load Growth Only Conditions, MWa

Year	Residential	Commercial	Industrial	Total
2027	925	814	1,043	2,782
2028	935	809	1,059	2,803
2029	949	806	1,080	2,835
2030	965	803	1,088	2,857
2031	985	800	1,108	2,893
2032	1,006	797	1,108	2,910
2033	1,027	795	1,115	2,936
2034	1,048	793	1,115	2,956
2035	1,070	793	1,115	2,978
2036	1,092	793	1,113	2,998
2037	1,113	795	1,119	3,027
2038	1,134	798	1,124	3,056
2039	1,154	802	1,128	3,083
2040	1,174	805	1,129	3,107
2041	1,192	810	1,138	3,139
2042	1,210	814	1,143	3,167
2043	1,226	819	1,149	3,194
2044	1,242	824	1,152	3,218
2045	1,255	829	1,160	3,244
Average annual growth rate	**1.7%**	**0.1%**	**0.6%**	**1.0%**

H.9 Load-Resource Balance

This appendix includes information on projected capacity and energy needs before portfolio analysis is conducted in ROSE-E. In alignment with OAR 860-090-0060(6), the needs assessments are conducted using the most recently available load forecast described in Appendix Section H.8[275] and do not include any incremental actions beyond known commitments at the time of the analysis, with the base existing portfolio described in Appendix Section H.6.8.[276]

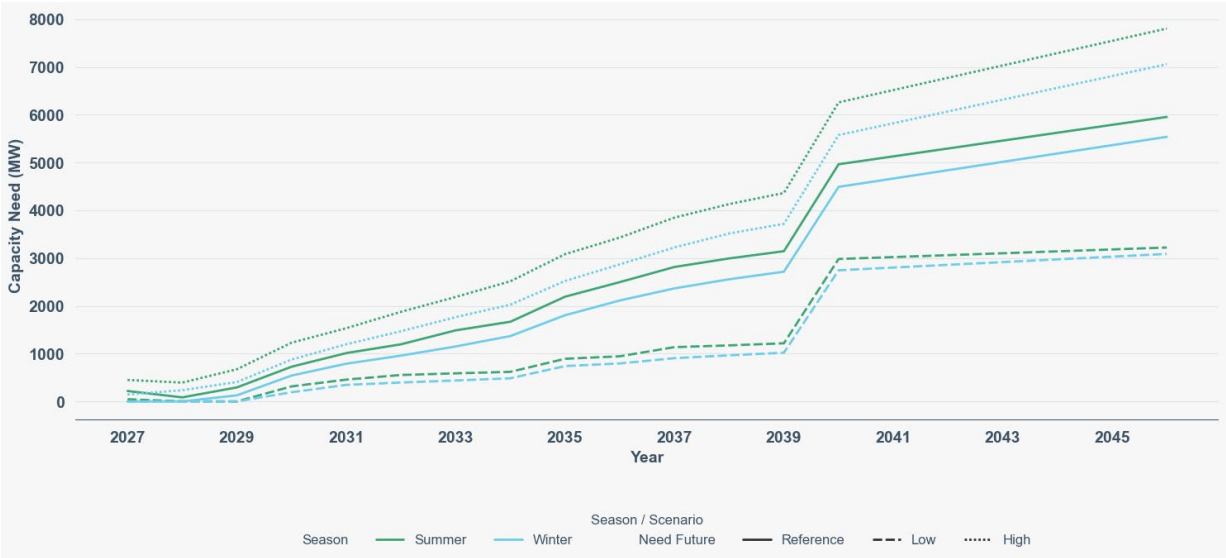
[275] Cost-effective energy efficiency and distributed energy resources are incorporated into PGE's load forecast as a reduction in future loads used in the needs assessments.
[276] As directed by OPUC in Docket No. LC 80, Order 24-096, Section VII.B.5, the base existing portfolio and needs assessment assume a 75% QF renewable success rate.

H.9.1 Capacity Need

Capacity need is the quantity of perfect capacity required to achieve a resource adequate portfolio. Capacity need is estimated in PGE's resource adequacy model, Sequoia, using a 1-event-day-in-10-years reliability metric. The reliability metric, or Loss of Load Expectation (LOLE) is set at 0.1, interpreted as 0.1 event days per year. An event day is measured as a 24-hour period where at least one loss of load hour occurs.[277] PGE first developed Sequoia during the 2019 IRP Update and used the model for the 2023 CEP/IRP, 2023 RFP, 2023 CEP/IRP Update, and 2025 RFP.[278]

Sequoia is used to estimate capacity need seasonally for the HB 2021 80% Emissions Reductions Regulatory Environment (HB 2021) (See Section 7.4.1.3) for Low, Reference, and High need futures across the 20-year planning horizon.[279] The various need futures represent changes in future load forecasts. Sequoia is also used to estimate Reference capacity needs for the Core Growth Only sensitivity. These 4 sets of estimates vary by load forecast only. The 2026 CEP/IRP includes a State Based RA sensitivity for which Sequoia is not used to derive capacity needs. For detail of the derivation of capacity needs for the State Based RA sensitivity see Appendix Section H.10. Figure 197 and Table 101 detail the Low, Reference, and High-capacity needs for the HB 2021 Regulatory Environment.

Figure 197. Seasonal Capacity Needs Across Planning Horizon



[277] G. Stephen et al., "Clarifying the Interpretation and Use of the LOLE Resource Adequacy Metric," 2022 17th International Conference on Probabilistic Methods Applied to Power Systems (PMAPS), Manchester, United Kingdom, 2022, pp. 1-4.
[278] Sequoia Overview. 2019 IRP Update, Appendix K. p. 75
[279] Seasons are defined as Summer (April – September) and Winter (October – March).

Table 101. Seasonal Capacity Needs Across Planning Horizon - HB 2021

	Need Future - Season					
	Low		Reference		High	
Year	Summer	Winter	Summer	Winter	Summer	Winter
2027	47	1	220	1	451	146
2028	4	1	86	1	395	236
2029	1	3	295	129	675	408
2030	316	194	728	543	1231	878
2031	458	348	1013	791	1534	1197
2032	555	397	1197	960	1877	1471
2033	589	440	1489	1152	2187	1765
2034	621	486	1669	1369	2516	2026
2035	894	742	2193	1805	3083	2522
2036	946	796	2498	2114	3431	2870
2037	1138	907	2815	2367	3848	3224
2038	1174	966	2994	2558	4131	3516
2039	1218	1021	3145	2716	4363	3718
2040	2982	2746	4964	4491	6259	5575
2041	3022	2803	5129	4666	6516	5822
2042	3062	2860	5294	4840	6774	6069
2043	3102	2917	5459	5014	7032	6316
2044	3142	2974	5624	5189	7289	6563
2045	3182	3031	5789	5364	7546	6810
2046	3222	3088	5954	5538	7804	7057

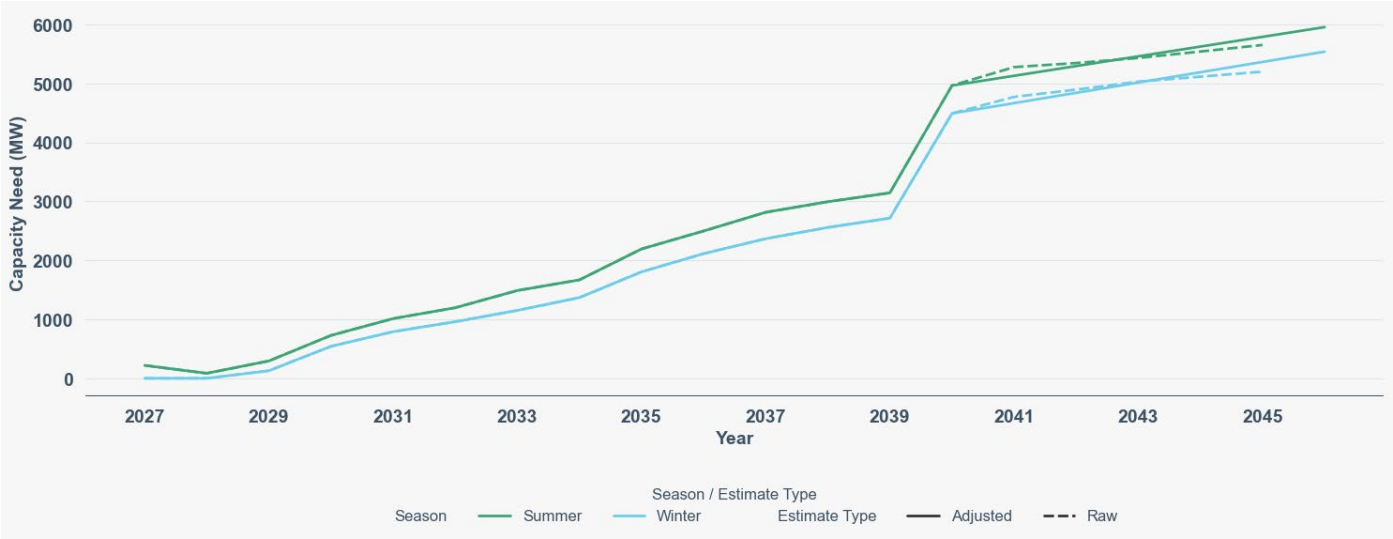
Capacity need estimates for each season in a forecast year are the result of approximately 1000 years of hourly stochastic load and supply simulations. For each simulation the system is optimized in discrete weeks with the objective of minimizing the greatest capacity shortfall and average energy shortfall.[280] This optimization does not include economic dispatch. The maximum daily unserved energy observations which result from the simulations are sorted in descending order to

[280] Although capacity need is defined seasonally using the 0.1 LOLE metric, this does not imply that the metric is additive and results in planning to a 0.2 LOLE. Seasonals are simulated independently, and the resulting capacity needs are unique constraints in portfolio expansion. This topic was previous discussed are part of LC 80 Round 1 Comments: https://edocs.puc.state.or.us/efdocs/HAC/lc80hac131341.pdf , during the 2023 CEP/IRP process.

derive the loss of load curve, where the 96th observation defines the capacity need.[281] Figure 181 in Appendix Section H.5.10 shows an illustrative example of how capacity need is defined.

One adjustment is made to the raw capacity needs as estimated in Sequoia. Many simulated weeks for years in 2040-2047 in the optimization problem are infeasible due to high loads relative to supply caused by the assumed exit of thermal resources in 2040. Such infeasibility reduces the sample size in the loss of load curve, biasing the calculated capacity need. This bias results in relatively flat growth in capacity needs in years beyond 2040. As such, seasonal needs for years 2041-2047 are extrapolated from year 2040 given the 2038-2039 growth rate. Figure 198 depicts the raw values for the reference case compared against the adjusted values used in portfolio expansion.

Figure 198. Reference Seasonal Capacity Need Adjustment Post 2040



Capacity needs for the Reliability Only Regulatory Environment (RO) are derived from those estimated for the HB 2021. Low, Reference, and High RO needs estimates are the same as the HB 2021 estimates, but do not include a step change in needs in the year 2040 caused by the assumed exit of thermal resources. Instead, the RO needs assume the growth rate from 2038-2039 is projected across the remainder of the planning horizon. Figure 199 displays the two (2) scenarios discussed above showing the resulting Reliability Only needs estimates. Table 102 details the Low, Reference, and High Capacity Needs for the Reliability Only scenario.

[281] The equation used to define the observation which defines capacity need is: $\frac{0.1}{365} \times 50{,}000 \times 7$. Where the 0.1 event-days per year (365 days) are allowed for the 350,000 days simulated per season.

Figure 199. Derivation of Reliability Only Seasonal Capacity Needs - Reference

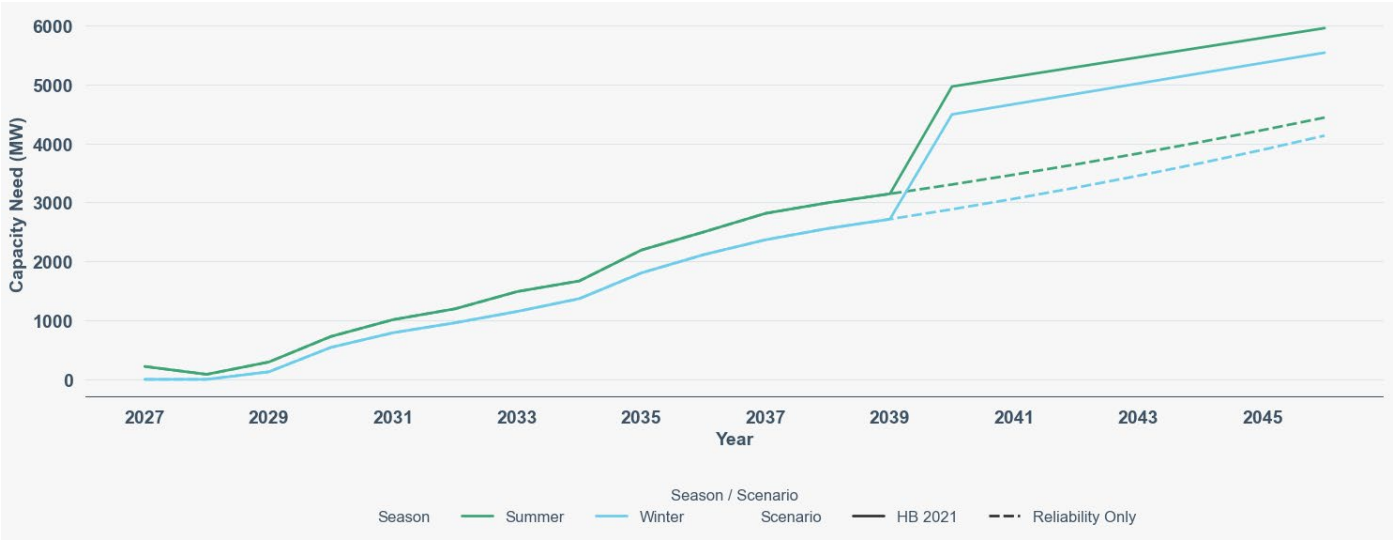


Table 102. Seasonal Capacity Needs Across Planning Horizon–Reliability Only

	Need Future - Season					
Year	Summer	Winter	Summer	Winter	Summer	Winter
2027	47	1	220	1	451	146
2028	4	1	86	1	395	236
2029	1	3	295	129	675	408
2030	316	194	728	543	1231	878
2031	458	348	1013	791	1534	1197
2032	555	397	1197	960	1877	1471
2033	589	440	1489	1152	2187	1765
2034	621	486	1669	1369	2516	2026
2035	894	742	2193	1805	3083	2522
2036	946	796	2498	2114	3431	2870
2037	1138	907	2815	2367	3848	3224
2038	1174	966	2994	2558	4131	3516
2039	1218	1021	3145	2716	4363	3718
2040	1264	1079	3304	2884	4608	3932
2041	1311	1141	3470	3062	4867	4157

	Need Future - Season					
2042	1360	1206	3645	3251	5140	4396
2043	1411	1274	3829	3452	5429	4649
2044	1464	1347	4022	3665	5734	4916
2045	1519	1423	4225	3891	6056	5198
2046	1576	1504	4438	4132	6396	5497

Sequoia is used to estimate Reference capacity need for the Core Growth Only Sensitivity. These needs represent a future with no growth from Schedule 96 customers as described in Section 6.1.3. Low and High need estimates for this alternative portfolio sensitivity are derived using the percentage difference from Reference to Low or High need futures as estimated in the HB 2021 80% Emissions Reduction scenario. Appendix Section details the capacity needs for the Core Growth Only scenario.

Figure 200. Comparison of Seasonal Capacity Needs–HB 2021 vs. Core Growth Only

Table 103. Seasonal Capacity Needs Across Planning Horizon–Core Growth Only

	Need Future - Season					
	Low		Reference		High	
Year	Summer	Winter	Summer	Winter	Summer	Winter
2027	37	1	174	1	357	146
2028	0	1	1	1	5	236
2029	0	0	69	1	158	3
2030	170	89	391	249	661	403
2031	244	175	539	397	816	601

	Need Future - Season					
2032	295	184	636	445	997	682
2033	269	186	681	486	1000	745
2034	271	194	727	547	1096	810
2035	413	338	1012	823	1423	1150
2036	413	329	1090	874	1497	1187
2037	515	381	1274	994	1742	1354
2038	518	404	1320	1070	1821	1471
2039	526	421	1358	1121	1884	1535
2040	1890	1746	3147	2855	3968	3544
2041	1879	1753	3189	2918	4052	3642
2042	1869	1762	3231	2982	4134	3739
2043	1860	1772	3273	3046	4216	3836
2044	1852	1782	3315	3109	4296	3932
2045	1845	1793	3357	3172	4376	4028
2046	1839	1804	3399	3236	4455	4124

H.9.2 Energy Need

An energy-load resource balance estimates the difference between PGE's forecasted customer load (demand) and the expected energy forecasted to be available to serve load (supply).

The forecasted amount of energy available annually in average megawatts (MWa) from owned and contracted non-dispatchable and non-emitting sources is calculated by multiplying the nameplate capacity of each facility by the forecast capacity factor in each year.

For Reliability Only and Continued Progress scenarios, the availability of energy from thermal resources with associated GHG emissions is calculated assuming the availability of the total capacity of PGE's thermal resources to serve load, with adjustments for seasonal temperature influences on operational capabilities.

For the GHG Glidepath scenario that complies with HB 2021 GHG emissions targets, the calculation of energy available annually from resources with associated GHG emissions uses a different methodology. As described in Appendix Section H.2.2.5, the total generation levels from PGE's dispatchable thermal plants are determined through economic dispatch from the PZM simulation for a given scenario. For these simulations, only a portion of the total energy produced by those plants through economic dispatch is retained to serve Oregon retail load. The amount of energy

that can be retained from market purchases and contracts with associated GHG emissions intensity is also accounted for in the PZM simulations.

When combined, the energy retained from GHG-emitting sources and the total energy from non-emitting sources determines the amount of energy allowed to serve Oregon retail load, summarized in Section 6.6.1.1.

H.10 Inputs for State Reliability Metrics Portfolio

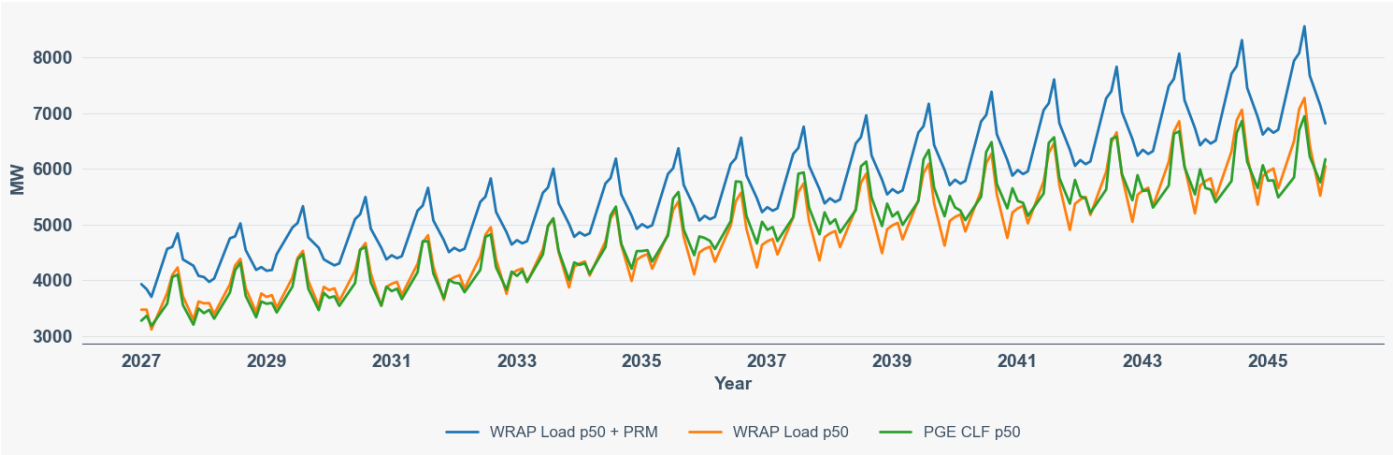
PGE used the Western Resource Adequacy Program (WRAP) to analyze the adequacy of PGE's system across the planning horizon. These methods provide the primary metrics needed to derive capacity need and ELCCs for portfolio modeling based on State reliability metrics, which currently rely on WRAP methodology. WRAP metrics for Summer 2027 and Winter 2026-2027 in the MID-C subregion, and WRAP's 2025 qualifying capacity contribution (QCC) estimates for PGE resources are the primary inputs for this exercise.[282, 283]

H.10.1 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 were 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.[284] A PGE specific annual growth rate of 3% was used to scale peak loads across the planning horizon.[285] 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.[286] Figure 201 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 shown. The figure shows there is close alignment in estimated 1:2 peak loads from PGE estimates and WRAP based estimates.

[282] https://www.westernpowerpool.org/private-media/documents/2024-12-12_Webinar_Summer_2026_and_2029_Data_final.pdf
[283] https://www.westernpowerpool.org/private-media/documents/2024-06-13_Webinar_Winter_2025-2026_and_2028-2029_Data.pdf
[284] https://pgn4.sharepoint.com/sites/2022IRPWritingProject/Shared%20Documents/IRP%20Update/BACKUP/V1.0_BPM_Forward_Showing_103_Forward_Showing_Capacity_Requirements
[285] WRAP's established growth rate is 1.1%, as defined in https://www.westernpowerpool.org/private-media/documents/V1.0_BPM_Forward_Showing_103_Forward_Showing_Capacity_Requirements.pdf. 1.1% was defined through and informal survey process, as described in the WRAP's https://www.westernpowerpool.org/private-media/documents/2023-03-10_WRAP_Draft_Design_Document_FINAL.pdf. Rather than use the establish growth rate for this exercise, PGE elected to estimate a growth rate specific its system.
[286] Preliminary values published 3-31-2024 used for winter season months.

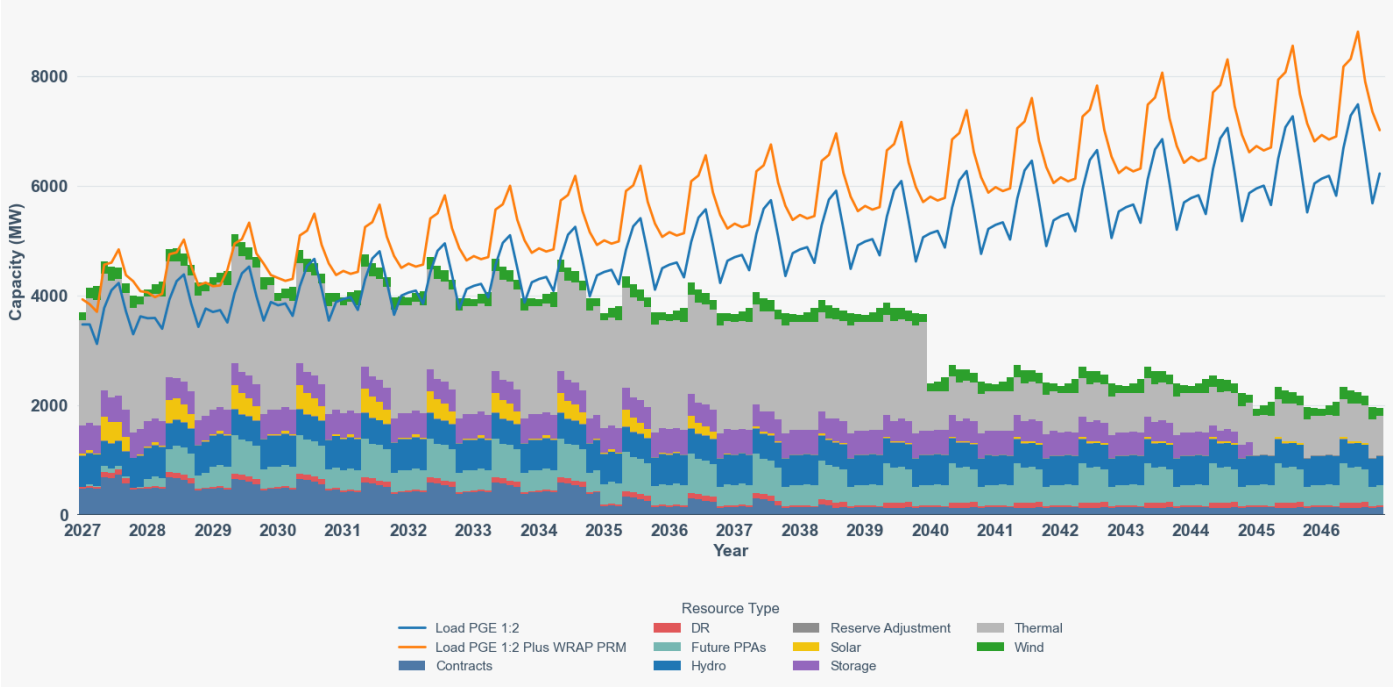
Figure 201. WRAP Based PGE 1:2 Peak Load and Planning Reserve Margin



H.10.2 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 26-27 Forward showing (FS) and Summer 2026 FS qualifying capacity values were used as 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. Figure 202 displays the supply assumptions that resulted from this WRAP based forecast compared against the WRAP based load forecast and planning reserve margin (PRM).

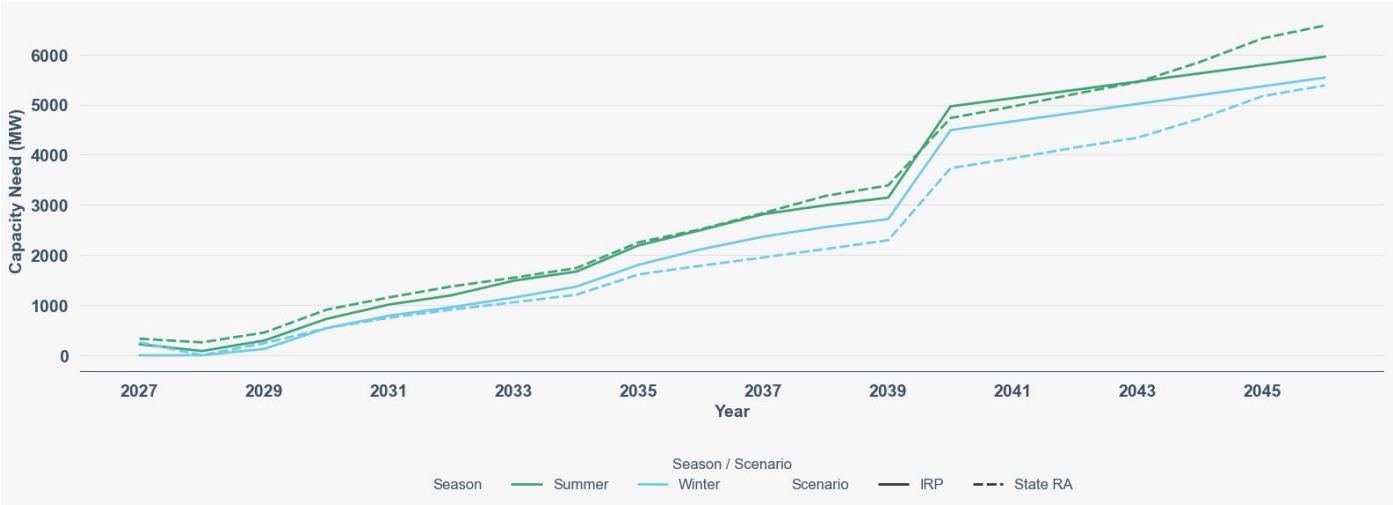
Figure 202. WRAP Based PGE Load Resource Balance



H.10.3 WRAP Based Capacity Need

Seasonal capacity need was calculated as the maximum monthly difference between WRAP based forecasts of load requirements and supply, as detailed above. Figure 203 shows the resulting capacity need as compared to the IRP-derived capacity need values as estimated in Sequoia. 2032 capacity need is approximately 175 MW more in Summer and 48 MW less in Winter using the WRAP based methods, compared against the IRP estimates from Sequoia.

Figure 203. IRP-WRAP Capacity Need Comparison

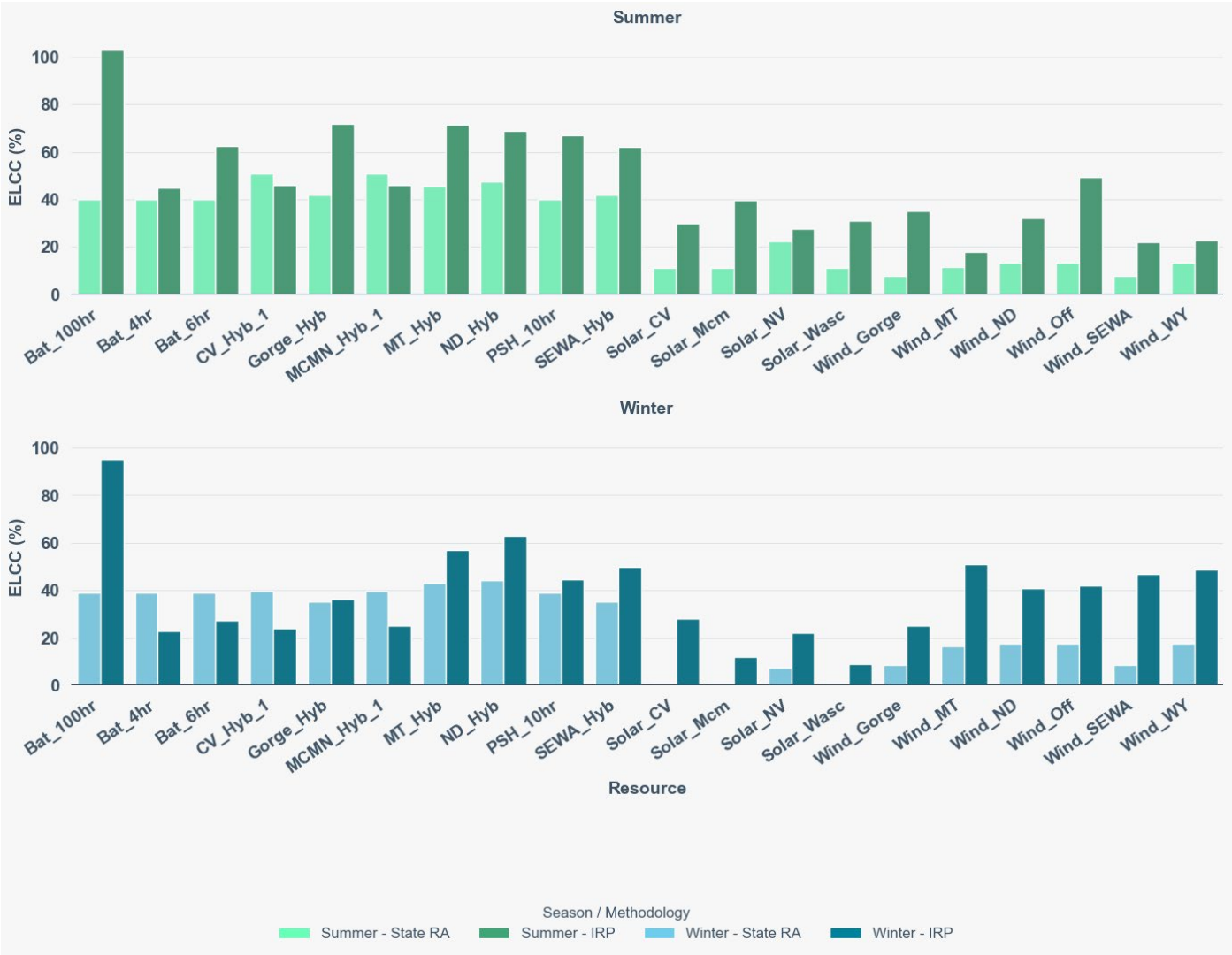


H.10.4 WRAP Based ELCCs

PGE used ELCC estimates from WRAP's summer 2027 and winter 2026-2027 adequacy assessment for the valuation of Proxy Resources in portfolio expansion modeling. The company used marginal ELCC values from the +9 GW entry scenarios provided by WRAP.[287] Figure 204 shows a comparison of WRAP marginal +9 GW ELCCs against those estimated in Sequoia. In general, WRAP ELCCs are less than IRP estimates for resources within the same WRAP zones. The primary divergence from this trend is for 4-hour storage resources in winter, where WRAP estimates are roughly twice that of the IRP. This difference contributes to greater WRAP solar plus storage hybrid estimates for the Christmas Valley 1:1 hybrid (CV_Hyb_1) and the McMinnville 1:1 hybrid.

[287] Marginal ELCCs derived from average ELCCs published at: https://www.westernpowerpool.org/resources/wrap_metrics/

Figure 204. IRP-WRAP ELCC Comparison



For PGE's Proxy Resources without a direct overlap with WRAP ELCCs, the following is assumed: 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, other smaller resources (e.g., EE, DERs, CBREs) maintain ELCCs as estimated in Sequoia.

Appendix I Scenario Descriptions

This appendix describes the policy context for select scenarios investigated in this CEP/IRP and describes certain model inputs and assumptions that aim to reflect the given policy for planning purposes. How the policy assumptions are then reflected in select models are further described in Appendix H on IRP modeling details and specific subsections where reference below. All scenarios analyzed meet renewable portfolio standards (RPS) policy requirements, as described in Section 6.6.1.3. A summary of scenarios analyzed is described in Table 23.

I.1 Reliability Only

The Reliability Only scenario focuses on a planning environment that meets reliability needs only within the IRP's portfolio analysis framework of cost-optimization. This scenario does not include enforcement of HB 2021 GHG emissions targets to understand the minimum system needs, absent additional decarbonization policy drivers. Drivers of system needs in the Reliability Only scenario include load growth, retirement/exit from the portfolio of existing resources, and compliance with RPS. In addition to the ability to retain the full output of PGE's existing natural thermal fleet, the Reliability Only scenario includes access to new contracts with existing natural gas facilities are available, in limited quantities. Natural gas contracts are available for selection in portfolio analysis in the amount of 200 MW starting in 2027, and an additional 400 MW starting in 2035.

I.2 HB 2021 Emissions Compliance

HB 2021 sets GHG emissions targets for PGE to meet. PGE must reduce GHG emissions associated with Oregon retail load reported under ORS 468A.280 to 1.62 million metric tons (MT) of carbon dioxide equivalent (CO2e) by 2030, 0.81 million metric tons by 2035 and zero metric tons by 2040 and every year after. These targets align with 80%, 90%, and 100% reductions, respectively, from a baseline set by ODEQ, informed by average 2010-2012 reported emissions. The baseline of 8.1 million MT CO2e and the forward-looking reduction targets are shown in Figure 10.

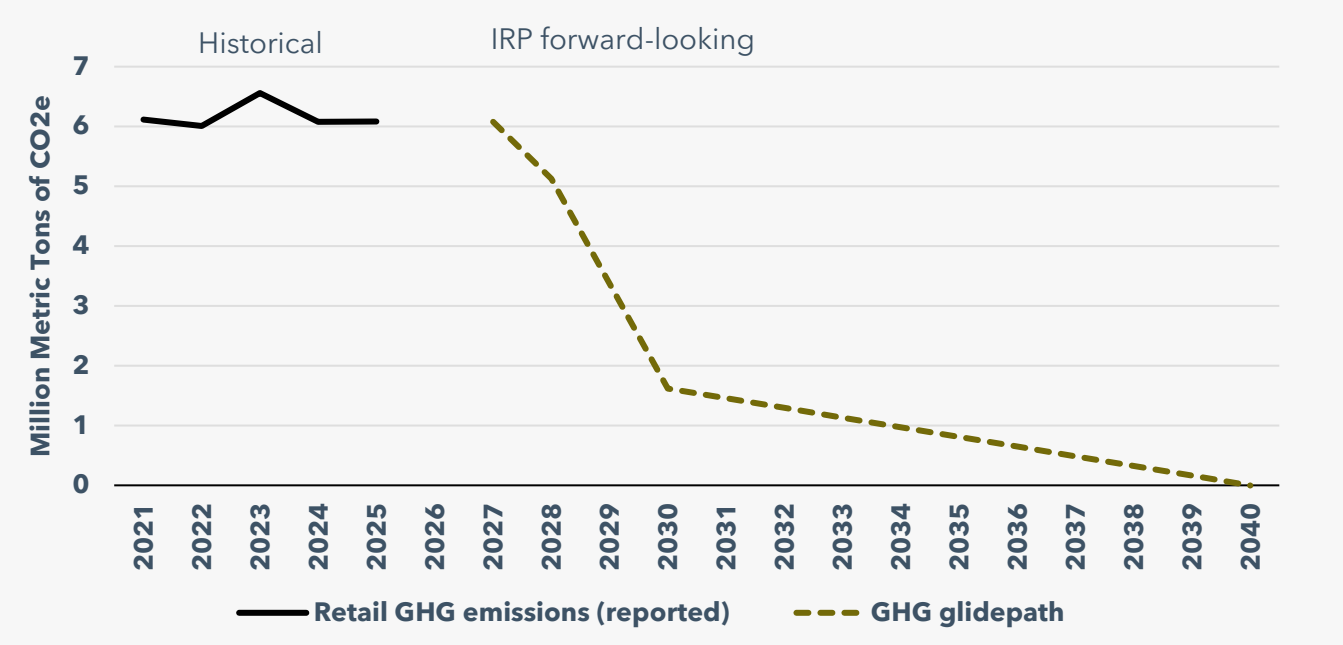
Regulated entities will continue to report annual GHG emissions to ODEQ, as they do today. In compliance years 2030, 2035 and 2040 and every year thereafter, the OPUC will use the data reported to ODEQ for that compliance year to determine whether the emissions targets are met. Due to annual variations as exampled in Section 1.2.1, the OPUC has stated that utilities should "achieve the 2030 and 2035 clean energy targets under typical or expected weather and hydro conditions…"[288] This implies that emissions may be higher or lower than the HB 2021 targets due to variability, but under average conditions meet the targets. PGE analyzes meeting the targets for planning purposes assuming average conditions. In accordance with OAR 860-090-100(8), the Preferred Portfolio is compliant with the HB 2021 emissions targets, as further presented in Section 7.6.

[288] 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.

The 2023 CEP/IRP was the first resource plan published by PGE that addressed the requirements of HB 2021. At that time, robust analysis was conducted to analyze different GHG emissions reduction glidepaths, or pace of progress, especially leading up to the first target in 2030.[289] A linear emissions glidepath, for planning purposes, was found to represent the best balance of costs, risks, and rate of emissions reduction and has since been relied on as the primary planning glidepath to the HB 2021 targets.

More recently, time, procurement activities, and federal policy changes have evolved to more realistically inform the pre-2030 GHG emissions glidepath, for planning purposes, for this IRP. Figure 205 shows the GHG glidepath assumed in scenarios that are compliant with the HB 2021 emissions targets.

Figure 205. GHG Emissions and Glidepath Associated with Serving Oregon Retail Load



This IRP begins with forward-looking year 2027. As Chapters 1, 3, and 6 describe, PGE is anticipating meaningful load growth and limited clean energy procurement options in the immediate-term. These conflicting factors limit PGE's ability to replace existing fossil fuel resources with clean in order to reduce emissions pre-2030, informing the non-linear progress assumed in these early years. GHG emissions limits for modeling start in 2027 at similar levels to recent actual reported emissions to reflect this immediate-term challenge, with non-linear decline to 2030 from there to ensure HB 2021 scenarios reflect meeting the first target.

[289] PGE's 2023 CEP/IRP, Appendix I, C-level Analysis and Appendix O, Thermal Operations/Output, https://downloads.ctfassets.net/416ywc1laqmd/6B6HLox3jBzYLXOBqskor5/63f5c6a615c6f2bc9e5df78ca27472bd/PGE_2023_CEP-IRP_REVISED_2023-06-30.pdf.

The modeling of the glidepath results in a limit of the thermal generation and market purchases with associated emissions retained for retail load through time. See Appendix Section H.2.2 for more information on how the GHG glidepath emissions limits are modeled in this IRP.

I.3 Continued Progress

HB 2021 includes provisions to pause compliance with the emissions targets, based on specific cost and/or reliability conditions. Section 10 of the bill describes cost cap conditions, with subsection (4) detailing "[u]pon a determination that the actual or anticipated cumulative rate impact calculated under subsection (3) of this section exceeds 6% of the annual revenue requirement for a year, the commission shall provide an exemption from further compliance with the requirements of sections 1 to 15 of this 2021 Act."[290]

PGE utilized the affordability offramp under HB 2021 Section 10 to inform select scenario analysis. Scenarios analyzed under these assumptions in portfolio analysis are referred to as "Continued Progress" scenarios because they allow for continued progress toward HB 2021 GHG emissions reduction targets, without being constrained to a specific GHG-reduction glidepath. This scenario does not intend to presuppose the outcome of any potential HB 2021 Section 10 investigation, which would be fact-specific, and does not yet have finalized rules.[291] The way the cost cap is represented in modeling is different than how the policy may be applied in reality and is further based in PGE-defined assumptions to work within the current IRP's portfolio analysis framework and model capabilities. Importantly, the scope of IRP cost analysis has never included total system revenue requirement nor rate impact estimates due to the uncertain nature of 20-year forecasts and detailed decision-making specific to individual rate cases. A high-level total system revenue requirement forecast is included and described here, only for the purposes of the cost cap scenario and should not be used outside the context of this CEP/IRP. In accordance with OAR 860-090-0060(7), any cost estimates used or presented in the CEP/IRP, should only be used for evaluation within the CEP/IRP context. Per the above, any future Section 10 investigation, should one be opened, would rely on known cost data to assess "actual or anticipated" revenue requirement impacts, rather than be based mostly in proxy modeling assumptions for IRP long-term planning purposes. Further, any IRP annual cost estimates are not equivalent to customer rate impacts, which are determined through different regulatory pathways, but IRP results can be used to shed light on the planning implications of cost-related impacts. This Continued Progress scenario is an illustrative IRP scenario that allows PGE to make comparisons based on model results and further directionally inform planning efforts based on more robust reflection in data analysis of policy considerations that may impact real-world decision-making.

The Continued Progress scenario applies a spending limit in portfolio analysis, over and above 'base' spending necessary for reflecting forecasted reliability only conditions. The base forecast first ensures the system is resource adequate in the reliability only scenario by adding new resources to meet load growth, after accounting for the existing resource mix and associated changes to it over

[290] https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB 2021/Enrolled.
[291] Details pending any relevant section 10 filings, of which none have yet been opened, in alignment with rules to be established through current OPUC open rulemaking in Docket No. AR 685.

time. For planning purposes, incremental spending beyond the additions for reliability may represent costs more associated with additional clean energy added to offset existing fossil fuels and enable decarbonization. Therefore, the Continued Progress scenario spending budget is calculated as 6% of the estimated revenue requirement of the base reliability only scenario to reflect additional spending that could occur over and above reliability needs, to then enable emissions reductions. Figure 206 shows the cost elements underlying the input cost assumptions for the Continued Progress scenario for application in portfolio analysis.

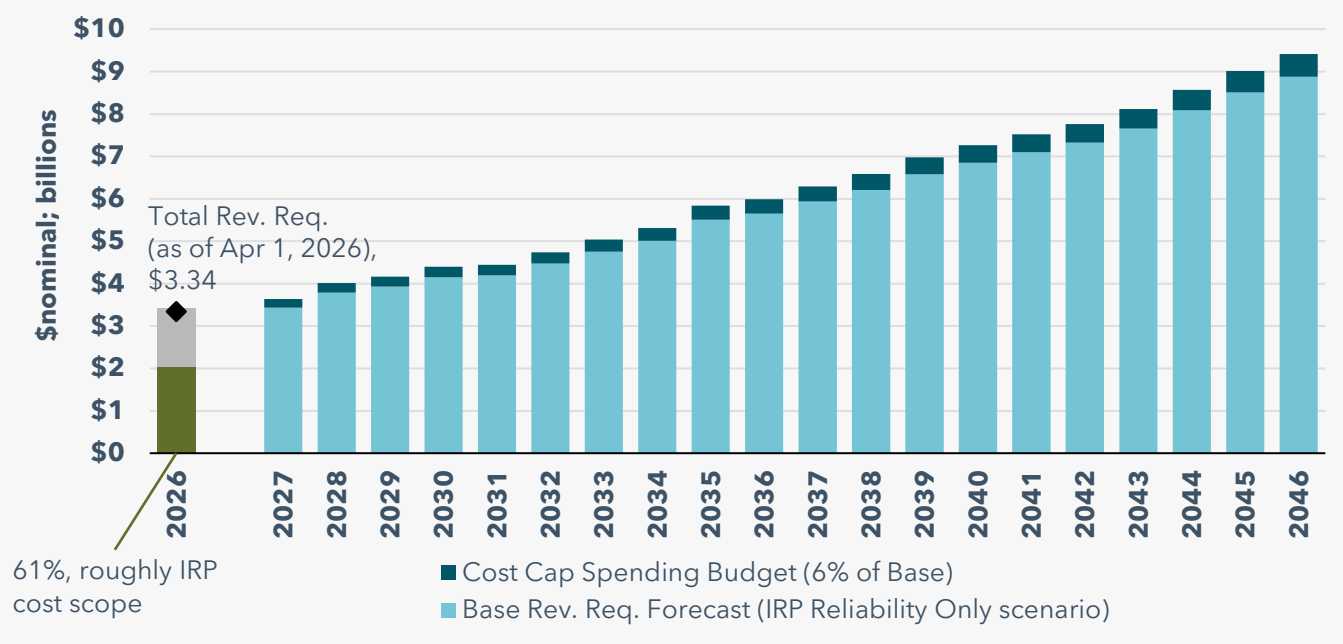
PGE uses a known "on the books" starting total system revenue requirement of $3.34 billion, set as of April 1, 2026.[292] For context, based on proxy existing resource costs assumed in IRP modeling, the scope of costs generally captured in IRP may represent roughly 60% of the total system revenue requirement. IRP costs typically reflect changes in generation and transmission costs only, and do not attempt to contemplate all utility-relevant spending nor revenues.

The total system revenue requirement for the year 2026 is first grown at the rate of inflation assumed in this IRP (roughly 2% per year as reported in Table 78) as a starting point for a 20-year forward view. Then, the revenue requirement is forecast over time to account for model results of the reliability only scenario's portfolio analysis results. This incorporates changes in fixed and variable costs (compared to today) of dispatching the changing existing portfolio under reference conditions and adds net costs in the future for new resource additions to meet reliability in the scenario.

This base revenue requirement forecast reflecting reliability only is then used to estimate the cost cap spending budget for application in the Continued Progress scenario. Per the HB 2021 Section 10 policy provisions, the cost cap is 6% of revenue requirement, thus 6% of the base revenue requirement forecast is estimated for each year to reflect the available spending amount toward more clean energy over and above meeting reliability only that could enable decarbonization. This cost cap spending budget is shown in Figure 206 as the dark stacked bars on top of the base revenue requirement forecast for the reliability only scenario. The figure also indicates that in general on a planning-basis, meeting Reliability Only will meaningfully increase costs and revenue requirement in the coming years as shown as the light bars compared to actual 2026 revenue requirement.

[292] This revenue requirement is inclusive of the ETO spending budget for energy efficiency deployment.

Figure 206. Revenue Requirement Input Development for Cost Cap Scenario



See Appendix Section H.6.5 for how this cost cap spending budget is applied in the ROSE-E model for cost cap scenarios in portfolio analysis for this IRP.

I.4 Core Load Growth Only

PGE has been refining load forecasting methodologies to differentiate between core load growth, and additional growth driven by new datacenters, often referred to as large load. See Appendix Section H.8.6.2 for more detail on assumptions and Appendix Section H.8.7 for forecasted load results. Portfolio analysis contemplates a range of scenarios that exclude this large customer load growth to focus on core load growth only. The relevant scenarios are described in Table 23 with results in Section 7.4.2.

I.5 Alternative Market GHG Emission Factor

PGE is required to estimate GHG emissions for forward-looking planning purposes in accordance with ODEQ's GHG reporting methodology defined in OAR Chapter 340, Division 215, and using assigned emission factors for CEP, as published on DEQ's website.[293] Current regulations require GHG emissions to be estimating using an Unspecified emission factor when the underlying source of generation for energy is purchased from the market (including from CAISO's Energy Imbalance Market), is unknown, or not otherwise specified in a contract.

In PGE planning, the market is represented as one zone in PZM economic dispatch simulations. Therefore, to align with ODEQ rules, the modeled market is assigned the Unspecified emission factor of 0.428 MT CO2e/MWh. This emission factor is roughly in-line with historical WECC-wide

[293] https://www.oregon.gov/deq/ghgp/Pages/Clean-Energy-Targets.aspx.

analyses using annual-level data and assumes the marginal unit most likely to support market purchases is a natural gas-fired power plant.

This Unspecified rate and ODEQ GHG emissions reporting rules do not capture the diversity of emitting and non-emitting resources that may be available on the market in any given year. Further, these current regulations, along with HB 2021's declining emissions targets, would eventually prohibit electric utilities from participating in centralized markets unless energy was acquired from generating resources known to be non-emitting. Current Oregon regulations do not account for evolving market resource mixes in the region. As such, these regulations do not provide viable options for Oregon utilities seeking to leverage the benefits of regional diversification on the market while delivering reliable power and complying with statutory clean energy targets.

PGE's 2023 CEP/IRP Update included scenarios that assumed a non-emitting market to be available, informed by a study conducted by the Brattle Group to forecast non-emitting energy available to PGE as clean energy surplus from a WECC-wide market in 2030.[294] For this 2026 CEP/IRP, PGE evolved the prior work to project an alternative Western market emission factor for each year of the planning horizon. These alternative (to ODEQ's Unspecified) annual emission factors incorporate future market resource mixes.

To project a market, PGE used forecasted state load and generation data by resource type from hourly Aurora simulations, similar to the data used in the Brattle Group study. The emissions accounting policy proposed in 2025 by stakeholders and CAISO's GHG Coordination working group was used by PGE as the basis for estimating annual market emission factors.[295] This policy is designed to be flexible for different reporting entity's needs in estimating post-market emissions for use in support of differing GHG reporting obligations. This CAISO policy mainly differs from how the Unspecified emission factor was developed because it relies on more detailed hourly-level data, rather than annual totals. On a high-level, the CAISO policy approach aims to estimate residual resources available in a market mix, both emitting and non-emitting, on an hourly level after balancing load The result is greater accuracy and precision for a residual market mix, even when the data is subsequently rolled up to an annual level.

For forward-looking analysis and given model data limitations, PGE made simplifying assumptions described in Table 104 for how the policy is deployed here with model data, compared to its potential real-world use by reporting entities using post-market actuals.

[294] "Estimating Hourly Clean Energy Surplus Available in the WECC Market", The Brattle Group, January 31, 2025, https://assets.ctfassets.net/416ywc1laqmd/7mZDwnJnvwNczJQ78fAk4m/a0a5516ee737ccd7f1aed5b09285ea1a/Brattle_PGE_Estimating_Hourly_Clean_Energy_Surplus_Available_in_the_WECC_Market__Appendix_F._Market_for_non-emitting_energy_.pdf.
[295] "Greenhouse Gas: Accounting and Reporting, Final Proposal", California ISO, October 15, 2025, https://stakeholdercenter.caiso.com/InitiativeDocuments/Accounting-and-Reporting-Final-Proposal-Greenhouse-Gas-Coordination-Working-Group-Oct-15-2025.pdf.

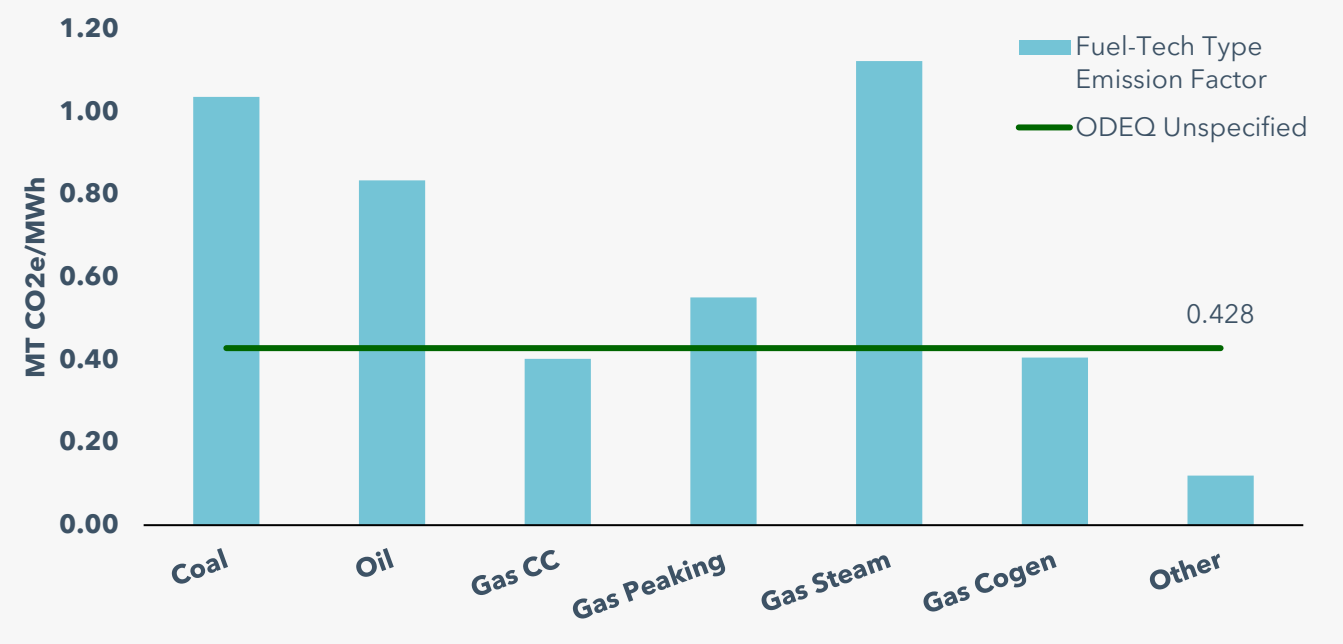
Table 104. Key Simplifying Assumptions to Represent CAISO Policy Approach with Model Data

Anticipated Real-World CAISO Policy Implementation	Simplification for PGE Planning with Model Data
Post-market actuals with data direct from reporting entities	Forecasted load and generation data, assuming all state clean goals on the books are met
Reporting entity-level load balancing	State-level data and load balancing
Owned generation, contractual agreements, and other entity-specific dispatch and details accounted for in load balancing	State-level generation mix informs state-level load balancing
Facility-specific emissions factors and analysis	Fuel-tech level emissions analysis
Reporting entity (i.e., utility) territory data	Western market assumed to include totals for the following 9 states: California, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Wyoming
Reporting entity selects residual mix methodology	CAISO policy "weighted average" methodology assumed for load balancing and residual mix

PGE applied the CAISO methodology to PGE model data, first by balancing each state's load at an hourly level with available state generating resources, assuming emitting and non-emitting resources proportionally served load based on their available generation in the given hour. If total generation exceeded load for the hour, then excess or residual energy was assumed to be available to the market at the same proportion of emitting and non-emitting used to serve load, in alignment with CAISO's "weighted average" approach to identifying a residual market mix. GHG emissions were estimated at the hourly level for the residual market mix, based on the amount of emitting generation, and resource fuel-tech type emission factors shown in Figure 207. GHG emission factors are facility-specific, based on fuel types burned, generation technology efficiencies, heat rate, and other facility specifications. While ODEQ publishes facility-specific emission factors, for this West-wide market analysis, generation at the resource type level was available in the model data. The simplified resource GHG emission factors for this analysis come from ODEQ published default data for subbituminous coal, distillate fuel oil, natural gas combined cycle (gas CC), and natural gas single cycle (gas peaking).[296] For gas steam, gas co-gen, and other emitting resource types, the emission factors are more technology specific and therefore an average for each was assumed, informed by ODEQ's published facility-specific emission factors.[297]

[296] https://www.oregon.gov/deq/ghgp/Pages/Clean-Energy-Targets.aspx.
[297] Ibid.

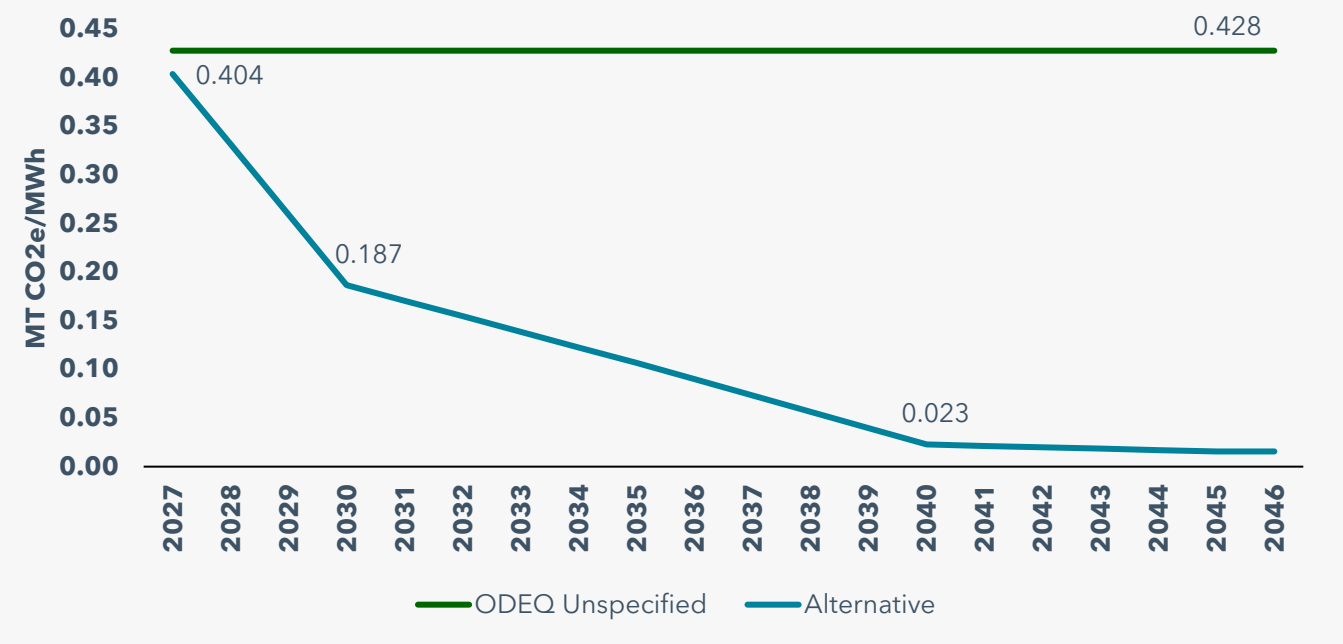
Figure 207. Alternative GHG Emission Factors by Resource Type



The hourly residual market mix of generation (in MWh) and GHG emissions (in MT CO2e) from each of the nine states in the analysis were summed for annual available-on-the-market totals. The total market emissions divided by the total market energy, both emitting and non-emitting, provided the annual market emission factor assumption for each year.

Given the large amount of data for the West at the hourly level, PGE performed the above analysis for each state for each hour of 2027, 2030, and every five years through 2045. Linear interpolation was used to fill in annual results for in-between years to provide market emission factor assumptions for each year of the planning horizon. The resulting market emission factor for each year are shown in Figure 208, along with ODEQ's Unspecified emission factor assumed in portfolio analysis. As the modeled West increasingly adds clean energy and replaces retiring fossil-fueled resources with lower-emitting alternatives over time, the estimated alternative market emission factor declines over time. This more detailed hourly-level load balancing approach finds more clean resources as residual and contributing to a market mix than is assumed in ODEQ's Unspecified rate, which is roughly the same as a natural gas-fired power plant in each year.

Figure 208. Market Emission Factor Assumptions – ODEQ vs. Regional Projection



This approach to estimating market emission factors allows PGE to quantify the potential impact that evolving regional resource mixes have on the marginal emissions of market purchases. Future analyses may include incorporating forecasted alternative market emissions factors into the PZM for economic dispatch simulations to explore the impact of varying market assumptions on overall thermal dispatch and costs in HB 2021 Emissions Compliance scenarios. While the CAISO policy is not yet implemented by any state regulator nor reporting entity, PGE believes it to be a reasonable approach for estimating an alternative market emission factor for planning purposes given the methodology was developed through robust stakeholder engagement and public processes.

Appendix J PGE Grid Enhancing Technologies (GETs) Strategy—2026 IRP

J.1 Introduction

This appendix provides an overview of Grid Enhancing Technologies ("GETs"), including how and where they are currently used on PGE's system, how they are incorporated into the capital planning process, and where they are anticipated to be deployed in the future. The term "GETs" refers to a number of technologies that are not poles and wires themselves, but which can support transmission infrastructure in various ways. These devices allow PGE to get the most out of its existing transmission system and can provide opportunities to delay or avoid larger capital projects in certain cases.

This is new content in the PGE IRP, and this information is provided in accordance with the requirements laid out in Oregon HB 3336[298] and OPUC Docket UM 2409.[299]

J.2 Overview of Planned Transmission Projects and Alternatives Considered, including GETs

Table 105 below lists all PGE transmission projects that are (1) greater than or equal to $10M in estimated costs,[300] (2) reliability driven, and (3) anticipated to be completed in 2026 or later. This table provides a list of the alternatives considered for each project, including GETs applications. A fuller description of each GETs technology is provided in the subsequent sections of this chapter.

Table 105. Planned Transmission Projects and Alternatives

Project #	Project Name	Anticipated In-Service Date	GETs Options Considered	Projected Cost [301]
P37590	Pearl-Sherwood Upgrades	2026	Advanced conductors (selected), topology optimization	$28.0M
P37447	Monitor Substation Rebuild	2026	Topology Optimization	$47.4M
P36954	Tonquin Substation Build	2027	Advanced conductors (selected), topology optimization, batteries as a transmission asset, dynamic line ratings	$61.0M
P37779	Murrayhill-Sherwood #1 & #2 reconductor	2027	Advanced conductors (selected), topology optimization, batteries as a transmission asset, dynamic line ratings	$38.7M

[298] https://olis.oregonlegislature.gov/liz/2025R1/Measures/Overview/HB3336
[299] https://apps.puc.state.or.us/edockets/DocketNoLayout.asp?DocketID=24817
[300] The >$10M project reporting threshold is established in OPUC guidance related to HB3336
[301] Projected costs and in-service dates are based off of PGE internal forecasts as of 5/7/2026 and subject to change.

Project #	Project Name	Anticipated In-Service Date	GETs Options Considered	Projected Cost [301]
P37769	St Marys-Sherwood Development	2028	Advanced conductors (selected), topology optimization, batteries as a transmission asset, dynamic line ratings	$66.7M
P39108	Horizon-Keeler 4000A upgrades	2028	Higher rated substation equipment (selected), batteries as a transmission asset	$10.7M
P36918	Harborton Reliability Phase 2 – 115kV	2028	Advanced conductors (selected), topology optimization, dynamic line ratings	$36.4M
P37468	Harborton Reliability Phase 3 – 230kV	2028	Advanced conductors (selected), topology optimization, batteries as a transmission asset, dynamic line ratings, power flow control devices	$25.0M
P39122	St Marys 115kV Substation Rebuild	2028	Topology optimization	$10.0M
P37488	St Louis Substation Rebuild	2028	Batteries as a transmission asset	$20.3M
P39185	Sherwood VWR3 Addition and 115kV Rebuild	2028	Topology optimization, batteries as a transmission asset	$35.0M
P36681	Main Substation Rebuild	2030	Batteries as a transmission asset	$62.5M

J.3 Pearl-Sherwood Upgrades

P37590

- This project will reconfigure and reconductor several 230kV transmission lines in the Wilsonville and Sherwood area.
- These transmission lines are the primary bottleneck for south-to-north flows across PGE's system. Upgrading these lines will allow for greater ability to import cost-effective solar power from California into the Portland region and points north, reducing energy procurement costs, and PGE's overall emissions profile.
- This project will utilize advanced high-temperature conductors and hardware. The reconductored lines will add +178% capacity compared to the existing facilities.

- Topology optimization or utilizing circuit breaker switching actions in the Wilsonville area was considered as a possible alternative; however, significant capacity limitations for south-to-north system flows would remain unresolved/unaddressed.

J.4 Monitor Substation Rebuild

P37447

- This project involves rebuilding the Monitor 230/57kV substation with new, dedicated areas for 230, 115, and 57kV equipment.
- The existing Monitor 230/57kV transformer is 67 years old (1959 vintage). PGE does not have any spare 230/57kV transformers in its service territory, as this is a unique asset. Replacing this transformer with modern 230/115kV and 115/57kV transformers provides an ability to use standardized spares and mitigates the current high risk of an aging asset failing.
- Options to order a new 230/57kV transformer were considered, however, given the impact this would have on spare strategy, they were not pursued.
- Topology optimization was also considered but determined insufficient if the 230/57kV existing transformer fails, because local switching actions do not mitigate the identified voltage violations and thermal overloading in the area. Ordering? standardized transformers, and rebuilding the substation to accommodate these assets, was the only viable strategy.
- The rebuilt Monitor substation will also underpin future transmission investments in the surrounding 57kV transmission system.

J.5 Tonquin Substation Build

P36954

- Tonquin substation is a new 115/13kV distribution substation. It was constructed to serve a combination of new customers and growth in existing customers in the Sherwood, Tualatin, and Wilsonville areas.
- This project also involves reconfiguring the transmission system in the surrounding area to provide better system reliability and avoid a number of identified transmission overloads under outage scenarios.
- The anticipated cost for the substation and all transmission work is $61.0M.
- Five alternative transmission topologies were considered for the area; however, none of them addressed the identified transmission overloads that would result under outage conditions. All of these arrangements would leave local customers in Sherwood, Tualatin, and Wilsonville vulnerable to sustained outages, particularly during extreme heat or cold.
- Utilizing a battery-as-a-storage asset was also considered; however, once constructed, a new battery asset would sit idle, waiting for transmission outages to occur. The total anticipated

cost of this battery solution was $213M. A battery asset was not considered a reasonable alternative to the proposed transmission solution.

- The newly built sections of transmission line constructed for this project will use advanced high-temperature conductors, which provide +64% capacity increase over existing lines in the area.
- Dynamic line sensors (for Dynamic Line Ratings – or DLR) were also considered for this project. As discussed later in the DLR section of this document, DLRs tend to provide operational flexibility under certain weather conditions but cannot be relied upon for permanent capacity increases on lines.

J.6 Murrayhill-Sherwood #1 and #2 Reconductor

P37779

- This project will reconductor two 230kV transmission lines in the Sherwood and Beaverton area. These lines form a bottleneck for south-to-north flows in PGE's system and are the next leg of 230kV transmission after completion of the Pearl-Sherwood upgrades.
- These transmission lines are the primary limiter for south-to-north flows across PGE's system. Upgrading these lines will allow for greater ability to import cost-effective solar power from California into the Portland region and points north, reducing energy procurement costs, and PGE's overall emissions profile.
- This project will utilize advanced high-temperature conductors and hardware. The reconductored lines will add +73% capacity compared to the existing facilities.
- PGE anticipates the construction of two (2) new battery energy storage systems connecting into Sherwood substation, with a total combined capacity of 400 MW. Studies indicated that reconductoring these 230kV lines will allow better use of the batteries, including a greater ability to charge during midday hours when low-cost power is most abundant.
- Dynamic line sensors were also considered for this project. As discussed later in the DLR section of this document, DLRs tend to provide operational flexibility under certain weather conditions but cannot be relied upon for permanent capacity increases on lines.

J.7 St Marys-Sherwood Development

P37769

- This project will reconductor one 230kV transmission line and construct one new 230kV transmission line in the Beaverton area. The existing single line forms a bottleneck for south-to-north flows in PGE's system and is the next leg of 230kV transmission after completion of the Murrayhill-Sherwood #1 and #2 reconductor projects.
- This transmission line is a primary limiter for south-to-north flows across PGE's system. Upgrading these lines will allow for greater ability to import cost-effective solar power from California into the Portland region and points north, reducing costs for energy procurement, and PGE's overall emissions profile.

- This project will utilize advanced high-temperature conductors and hardware. The reconductored lines will add +73% capacity compared to the existing facilities.
- PGE anticipates the construction of two (2) new battery energy storage systems connecting into Sherwood substation, with a total combined capacity of 400 MW. Studies indicated that, by reconductoring these 230kV lines, it will allow better use of the batteries, including a greater ability to charge during midday hours when cheap power is most abundant.
- An alternative transmission arrangement was considered for this project, which would have connected two (2) additional transmission lines into the Murrayhill substation. However, this would have required the installation of 230kV gas-insulated switchgear at Murrayhill, with expected costs increasing by +$20M. This alternative was not selected.
- Dynamic line sensors were also considered for this project. As discussed later in the DLR section of this document, DLRs tend to provide operational flexibility under certain weather conditions but cannot be relied upon for permanent capacity increases on lines.

J.8 Horizon-Keeler 4000A Upgrades

P39108

- This project upgrades terminal equipment (circuit breakers, switches, and buswork) at both the PGE Horizon substation and the BPA Keeler substation.
- The transmission lines connecting these two substations are being upgraded as part of a separate project (P37774).
- In order to get the maximum usage out of existing PGE transmission facilities, PGE and BPA plan to upgrade the terminal equipment at both substations to 4000 amp equipment. This is the first use case for 4000 amp rated equipment in PGE service territory.
- The use of the nearby Constable battery energy storage system to alleviate identified transmission overloads on these facilities was studied but ultimately proved insufficient to eliminate all identified overloads.

J.9 Harborton Phase 2 – 115kV

P36918

- This project reconfigures the existing transmission system in the Portland area, and provides a new, stronger 115kV transmission source from Harborton substation to Wacker substation.
- Completing this project will increase reliability in the Portland area, by reducing the previous reliance on a long 115kV transmission source from Beaverton into the area and replacing it with a much closer transmission source at Harborton substation. This will improve the voltage profile in the area and eliminate identified thermal overloads on nearby transmission facilities.
- This project will utilize advanced high-temperature conductors and hardware. The reconductored lines will add +114% capacity compared to the existing facilities.

- Dynamic line sensors were also considered for this project. As discussed later in the DLR section of this document, DLRs tend to provide operational flexibility under certain weather conditions but cannot be relied upon for permanent capacity increases on lines.

J.10 Harborton Reliability Project – Phase 3 230kV

P37468

- This project reconfigures an existing three-terminal 230kV line, constructs approximately 0.25 miles of new 230kV lines, and also reconductors 0.25 miles of existing conductor, to create three new 230kV transmission circuits into Harborton substation in Portland within an existing utility easement.
- This project is required to support regional reliability, relieving a system chokepoint and providing for better ability to import power into PGE's system both from the north and from the south under varying system conditions.
- This project is critical to local transmission reliability and load service. If this project is not constructed, customers in parts of the Portland region face severe risk of power outages, especially during times of grid stress, such as heat events and cold snaps, as soon as 2028.
- A myriad of alternative routing options were considered for this project. No viable alternative route was identified. The proposed route utilizes existing PGE easements.
- Deployment of resources such as rooftop solar or similar "behind-the-meter" devices was also considered. This approach will not provide nearly the magnitude of relief needed to solve for the transmission constraints forecast for the Portland area by 2028. For comparison, the Portland area of concern is facing a 238 MW deficit in transmission capacity, and today there exists only 12 MW of rooftop solar and 8 MW of distributed storage capacity in the same area. Scaling the necessary distributed capacity up by 2028 is not a realistic approach to solving the identified transmission system constraints, even when ignoring the challenges for rooftop solar when the sun is not shining and sufficient storage is not available.
- Since this project requires the construction of 0.25 miles of new transmission facilities to physically connect into the Harborton substation, the option of reconductoring is not available in this situation. The newly constructed sections of line will utilize advanced conductors that provide +143% capacity increase over existing 230kV lines in the area.

J.11 St Marys 115kV Substation Rebuild

P39122

- This project involves replacing 115kV circuit breakers at St Marys substation. The existing breakers have a lower fault interrupting capability. Due to upcoming transmission topology changes in the area, the St Marys substation is expected to experience an increase in fault currents, which could exceed the rated interrupting capability of the existing breakers

- Breakers that attempt to interrupt a fault current higher than their rated capability risk catastrophic failure, which is both a serious safety concern and a reliability impact to customers.
- The replacement breakers will have interrupting capability in excess of any future anticipated fault currents at St Marys substation.
- Reconfiguration of the existing 230kV transmission system was considered as an alternative. No arrangement was identified that could prevent excessive fault currents to the existing breakers.

J.12 St Louis Substation Rebuild

P37488

- This project rebuilds the existing St Louis 57kV substation, including insulating the facility for future use at 115kV.
- This project addresses aging asset replacement. It is also part of a broader sequence of projects that will eventually upgrade multiple substation and transmission lines in the area to 115kV. Operating transmission at 115kV provides increases capacity to serve load, and in general better system reliability to customers at these locations.
- Customers served by St Louis substation experienced significant outages during the 2021 ice storm event. This rebuild will help prevent the frequency and duration of customer outages during future storm events.
- Batteries were considered as an alternative option at this location. However, this would not address the aging asset concerns at this substation. Batteries also exhibited severe restrictions on charging, due to the limited capacity on the existing 57kV system serving this substation. Batteries were not pursued as an alternative to rebuilding this substation.

J.13 Sherwood VWR3 Addition and 115kV Rebuild

P39185

- This project addresses load growth in the Sherwood, Tualatin, and Wilsonville areas, by adding a third 230/115kV transformer at Sherwood substation and rebuilding the 115kV yard at Sherwood in order to accommodate this new equipment.
- This project will provide for additional customer capacity in the area, by relieving loading on the two (2) most heavily loaded bulk power transformers in PGE's system today – Sherwood VWR1 and Sherwood VWR2.
- The impact of two (2) anticipated Sherwood batteries, totaling 400 MW, was studied as part of this project. It was determined that the presence of these batteries increases the need for the Sherwood VWR3 transformer, and that they could not be utilized to avoid the project.

J.14 Main Substation Rebuild

P36681

- This project converts the existing 57kV Main substation in Hillsboro, Oregon to a 115kV substation. Operating the substation from the 115kV transmission system will provide increased reliability to customers served from this substation.
- This project will move significant load off the currently constrained 57kV transmission system, providing additional capacity for future load growth in Cornelius, North Plains, Banks, and the surrounding communities.
- Batteries were considered as an alternative to this project. It was determined that batteries would be severely limited from charging during most system conditions, due to the limited capacity on the existing 57kV transmission network and would not be a viable option.

Additionally, Table 106 below describes recent PGE transmission projects under $10M in total costs that involve significant use of GETs deployments:

Table 106. PGE Transmission Projects Under $10M in Total Costs

P#	Project Name	Anticipated In-Service Date	Notes	Projected Cost[302]
P39043	McLoughlin V248 Breaker Replacement	2025	While the main driver of this project was replacement of aging assets, it also provided significant additional opportunities for topology optimization on the 230kV network in the Oregon City area	$1.01M
P37774	Horizon-Keeler #1 230kV reconductor and Horizon-Keeler #2 upgrade	2026	This project was the first PGE use case for ceramic coating on transmission lines, which provide +10-12% rating increase.	$2.4M
P39135	Dynamic Line Ratings	2026+	This project has deployed Dynamic Line Rating sensors on 14 PGE transmission lines, with several more line deployments planned. See the DLR section for additional details.	$6.4M

J.15 McLoughlin V248 Breaker Replacement

P39043

- Project replaced an aging 230kV oil circuit breaker at McLoughlin substation in Oregon City.
- Existing breaker, in addition to being an aging asset, also prevented certain circuit breaker closing actions on the surrounding 230kV transmission system due to limited fault interruption capability
- Replacement breaker provides higher fault interruption capability. This provides PGE operators with more flexibility to utilize topology optimization (certain switching actions in

[302] Projected costs and in-service dates are based off of PGE internal forecasts as of 5/7/2026 and subject to change.

the area) that they previously could not, and redirect power flows under certain conditions. This improves the overall reliability of PGE's system.

- By utilizing topology optimization, PGE also deferred the need for a reconductor of the Canemah-McLoughlin 115kV transmission line, which is anticipated to cost $11M. Without the McLoughlin V248 breaker replacement, that project would have been needed by 2030, but is now expected to be deferred to at least 2035.

J.16 Horizon-Keeler #1 230kV Reconductor and #2 Upgrade

P37774

- This project reconductored the 1.4 mile long Horizon-Keeler #1 230kV line. The replacement conductor utilized high temperature conductor and hardware.
- The replacement conductor also was ordered with a proprietary advanced coating called E3X. This coating allows the conductor to absorb less heat from the sun, and dissipate heat more effectively into the surrounding air.
- The overall capacity increase the Horizon-Keeler #1 230kV line due to this project was +90%. This project did not require any additional right-of-way space usage.
- This project also involved an upgrade to the Horizon-Keeler #2 230kV line. The #2 line already utilized high temperature conductor and hardware, but did not have an advanced conductor coating applied. A different conductor coating company, Prysmian, will be utilizing a robot to apply a coating to the #2 line. This work is scheduled for Fall 2026. The anticipated increase from the conductor coating on the #2 line will be +19% capacity.
- By utilizing new conductor coatings, both on ordered conductor, and on conductor already in the air, from different manufactures, PGE will be able to better assess the best use of these technologies on future projects.

J.17 Dynamic Line Ratings

P39135

J.17.1 Advanced Conductors

This section presents Portland General Electric's (PGE) strategy for deploying advanced conductors and conductor coatings on the 115 kV and 230 kV transmission system to meet growing capacity needs in a cost effective, reliable, and constructible manner. As system demand increases and the grid evolves to support new resources, PGE has transitioned toward advanced conductor technologies that allow significantly higher ampacity while maintaining clearance, structural integrity, and operational reliability as compared to traditional conductors.

PGE's strategy is centered on the use of high-temperature conductors, particularly Aluminum Conductor Steel-Supported (ACSS) conductors, as the standard solution for most new transmission construction and reconductoring projects. These conductors provide high continuous operating temperatures, predictable sag performance, and a proven, conventional construction approach, at a lower overall life-cycle cost than alternative advanced conductor technologies. PGE has extensive

operational experience with ACSS conductors and continues to expand their use. While early installations were designed for continuous operation at 180 °C, PGE has more recently transitioned to designing new projects for continuous operations up to 250 °C to unlock additional capacity without requiring major structural upgrades or right-of-way modifications compared to traditional conductors.

While ACSS meets the technical definition of an advanced conductor, the term "advanced conductor" is now commonly used to describe High-Temperature Low-Sag (HTLS) conductors that employ composite core designs in place of steel. In addition to ACSS, the market offers several types of HTLS conductors that use composite cores to reduce thermal expansion and sag. Currently high temperature low sag conductors are evaluated as part of PGE's structured conductor selection process but are treated as a specialized solution rather than a default choice. While these conductors offer reduced thermal sag and high mechanical strength, their higher material costs, logistical complexity, and in some cases lower effective thermal capability limit their cost effectiveness for most applications. PGE expects that HTLS conductors provide the greatest value in locations with extreme physical constraints, such as long spans, river crossings, or retrofit projects where structure replacement is particularly challenging.

In parallel, PGE is incorporating advanced conductor coatings as a grid enhancing technology to further increase the thermal performance of both new and existing conductors. By reducing solar heat absorption and improving heat dissipation, these coatings allow higher power transfer or lower operating temperatures without changes to conductor size or supporting structures. Factory applied coatings are being specified for select new projects, while robotic application methods are being evaluated to retrofit in-service lines. This approach provides a flexible and incremental pathway to increase transmission capacity with minimal outage duration and capital cost.

J.17.2 Explanation of Conductor Types

J.17.2.1 Traditional Conductors

The two (2) traditional conductor types used on PGE's transmission system are:

- AAC (All-Aluminum Conductor)
- ACSR (Aluminum Conductor Steel-Reinforced)

In both designs, the aluminum strands provide the majority of the mechanical strength. If conductor temperature remains below approximately 100°C, the aluminum retains its tensile properties. Above that threshold, aluminum begins to anneal, permanently losing strength. This limits both allowable operating temperature and practical ampacity, even though higher temperature would otherwise allow more current. As a result, traditional conductors are fundamentally constrained by metallurgy, not electrical capability.

J.17.2.2 Definition of Advanced Conductors

The Electric Power Research Institute (EPRI) defines advanced conductors as those that can operate at temperatures above 100 °C for extended periods without experiencing loss of mechanical strength or degradation of electrical or chemical performance. Because advanced conductors can

operate at higher temperatures, they can achieve significantly higher ampacity than traditional conductors. There are two (2) categories of conductors that meet this definition:

- High-Temperature (HT) Conductors
- High-Temperature Low-Sag (HTLS) Conductors

J.17.2.3 High-Temperature Conductors (HT)

The first commercially successful advanced conductor was Aluminum Conductor Steel-Supported (ACSS). ACSS uses fully annealed aluminum strands over a high-strength steel core. Because the aluminum is already annealed, further exposure to high temperature does not degrade its strength. All mechanical load is carried by the steel core, allowing continuous operation well above 100 °C.

Modern ACSS designs include a zinc–5% aluminum alloy coating with mischmetal additives on the steel core, providing enhanced corrosion resistance and allowing continuous operation up to 250 °C without loss of strength.

This combination of durability and thermal performance explains why ACSS has become the preferred choice for transmission development at PGE for 115 kV and 230 kV projects. It balances performance with practicality, offering a reliable solution for most new projects.

J.17.2.4 High-Temperature Low-Sag Conductors (HTLS)

While ACSS meets the technical definition of an advanced conductor, the term "advanced conductor" is now commonly used to describe High-Temperature Low-Sag (HTLS) conductors. HTLS conductors replace the traditional steel core with a composite core (such as carbon fiber, glass fiber, ceramic fibers or hybrid materials). While designs vary by manufacturer, HTLS conductors share three key performance characteristics:

- High-temperature capability: Continuous operation typically in the range of 180 °C to 210 °C, enabling higher ampacity relative to traditional conductors.
- Reduced sag: Composite cores have a much lower coefficient of thermal expansion than steel, resulting in significantly less thermal sag
- High mechanical strength: Composite cores provide equal or greater strength compared to conventional steel cores

These properties allow HTLS conductors to deliver very high ampacity while maintaining clearance, making them well suited for reconductoring projects and capacity upgrades on existing transmission lines.

There are several different types of HTLS available on the domestic market. The types of high temperature low sag conductor that PGE has considered in conductor selection studies have been:

- CTC Global: Aluminum Conductor Composite Core (ACCC)
- A single high-strength carbon- and glass-fiber composite core carries all mechanical load, with fully annealed aluminum strands carrying all current.
- 3M: Aluminum Conductor Composite Reinforced (ACCR)

- A stranded ceramic-fiber aluminum-matrix composite core provides strength and low thermal expansion. Heat-resistant aluminum-zirconium strands share mechanical loading.
- Southwire: C7 Aluminum Conductor Composite Supported (ACCS)
- A stranded carbon-fiber composite core carries all mechanical load, with fully annealed aluminum strands carrying all current.
- Southwire: C7 Aluminum Conductor Composite Reinforced (ACCR)
- A stranded carbon-fiber composite core paired with aluminum-zirconium strands, allowing load sharing between core and aluminum.
- TS Conductor: Aluminum Encapsulated Carbon Core (AECC)
- A pre-tensioned carbon-fiber core fully encapsulated in aluminum, protecting against moisture, oxygen, and galvanic corrosion. The composite core carries all mechanical load while fully annealed aluminum strands carry all the electrical current.

J.17.2.5 Coated Conductor

Conductor coatings are engineered surface treatments that improve the thermal performance of conductors by reducing solar heat absorption and increasing heat dissipation. By keeping conductor's cooler for a given electrical load, these coatings allow either higher ampacity or lower operating temperatures, improving capacity and/or efficiency. They are particularly valuable when used on advanced conductors, which are often limited not by material strength but by surface heat buildup.

Conductor coatings work by modifying two key surface properties of the conductor: solar absorptivity and thermal emissivity. Spectrally selective coating materials reflect a greater portion of incoming solar radiation, reducing daytime heating, while simultaneously providing a high-emissivity surface that radiates heat more effectively. This combination allows the conductor to shed heat faster and operate at a lower temperature for the same current. Bare aluminum conductors typically have low emissivity when new and only reach higher values after years of weathering; coated conductors achieve high and predictable emissivity from the time of installation, providing immediate and sustained thermal benefits.

These thermal improvements translate directly into operational and economic value. By keeping conductor temperatures lower, coatings enable higher current flow without exceeding thermal limits, increasing power transfer capability. Lower operating temperatures also reduce electrical resistance, which decreases line losses and improves overall system efficiency. In addition, cooler conductors experience less thermal expansion and sag, improving clearance margins and reliability during peak loading and high solar conditions. Coatings can be applied during conductor manufacturing or applied in situ using robotic equipment, providing a low-cost upgrade path that, in some cases, can defer or eliminate the need for full reconductoring.

To illustrate the impacts of conductor selection on project capacity, the approximate capacity for various conductor types is listed in Table 107 and Table 108 for two (2) standard conductor sizes

that PGE utilizes – 795 kcmil[303] (used in 115kV applications) and 2156 kcmil (used in 230kV applications).

Table 107. Capacity Increases for Various Conductor Types, 115kV Applications

Conductor Type	Uprate over AAC
795 All-aluminum conductor (AAC)	n/a
795 Aluminum conductor, steel reinforced (ACSR)	+10.6%
795 Aluminum Conductor, Steel Supported (ACSS), operated at 180°C	+64.1%
795 ACSS, operated at 250°C	+95.8%
795 ACSS, operated at 250°C and with advanced coating applied	+122.9%
Equivalent High-Temperature, Low-Sag conductor	Varies, up to +83.4%

Table 108. Capacity Increases for Various Conductor Types, 230kV Applications

Conductor Type	Uprate over AAC
2156 All-aluminum conductor (AAC)	n/a
2156 Aluminum conductor, steel reinforced (ACSR)	+7.8%
2156 Aluminum Conductor, Steel Supported (ACSS), operated at 180°C	+64.1%
2156 ACSS, operated at 250°C	+99.1%
2156 ACSS, operated at 250°C and with advanced coating applied	+130.7%
Equivalent High-Temperature, Low-Sag conductor	Varies, up to +69.3%

J.17.2.6 Advanced Conductor Applications

Over the past decade, nearly all new 115 kV and 230 kV transmission projects at PGE, including new lines, rebuilds, and reconductoring projects, have been scoped using advanced conductors. Traditional AAC and ACSR conductors are generally no longer considered for projects involving significant capital investment because they cannot deliver the thermal capability, and long-term capacity required of the modern grid. Table 109 below describes upcoming PGE transmission projects that will utilize advanced conductor arrangements.

[303] The abbreviation "kcmil" stands for "thousands of circular mils" and is a measure of a conductor's cross sectional area.

Table 109. Upcoming Deployments of Advanced Conductors on PGE's Transmission System

P#	Funding Project Name	Estimated In-Service Date	Conductor Type	Notes [304]
P37774	Horizon-Keeler BPA #1 Development: 230 kV Reconductor	Sep 2026	ACSS	High Temperature Design
P37590	Pearl-Sherwood Upgrades	Dec 2026	ACSS	High Temperature Design
P36954	Tonquin Substation Build	Jul 2027	ACSS	-
PXX111	Shute and Sunset Facility Upgrades	Mar 2028	ACSS	High Temperature Design
P39108	Horizon 4000A Upgrades	Jun 2028	ACSS	High Temperature Design Advanced coatings will be applied to existing lines (possibly by robotic application)
P37266	Reedville Substation Rebuild	Jul 2028	ACSS	-
P37468	Harborton Reliability Ph2 - 230kV	Aug 2028	ACSS	-
P39015	Blue Lake-Glendoveer Reconductor	Aug 2028	ACSS	-
P37769	St Marys-Sherwood Rebuild to 230 kV line	Dec 2028	ACSS	High Temperature Design Conductor to be ordered with Advanced Coating already applied
P37779	Murrayhill-Sherwood #1 & #2 Development	Dec 2028	ACSS	High Temperature Design Conductor to be ordered with Advanced Coating already applied

Future transmission projects are also under study, which may utilize ACSS or possibly HTLS conductor options depending on use case, anticipated costs, and impacts to constructability and long-term maintenance.

For new transmission segments and full rebuilds, high temperature conductors are the default solution. They provide the best combination of ampacity, mechanical performance, constructability, and life cycle cost.

For reconductoring projects, PGE applies a structured conductor selection process during the scoping phase. Both high temperature and high temperature low sag conductors are evaluated. The conductor ultimately selected is the one that meets the required ampacity while minimizing

[304] Where noted, "High Temperature Design" indicates conductors, hardware, and sag clearances that have been specially designed to be operated up to 250°C, versus a standard maximum operating temperature of 180°C for ACSS-type conductors

total installed and life cycle cost, including impacts on structures, construction, spare material, and long-term operation.

J.17.2.7 High Temperature Conductor

PGE installed its first high temperature conductor in 2006 and now operates more than 120 circuit miles of ACSS on its 115 kV and 230 kV systems. The standard ACSS conductors in service include:

- 795 kcmil ACSS (26AL 7S) "Drake"
- 1272 kcmil ACSS (54AL 19S) "Pheasant"
- 2156 kcmil ACSS (84AL 19S) "Bluebird"

Early installations were designed for 180 °C continuous operation. To further increase transmission capacity, PGE now designs new projects and reconductoring projects for 250 °C continuous operation. This change increases line ampacity by approximately 14 to 21% without requiring changes to structure strength or right-of-way widths, and only minimal adjustments to structure height compared to the previous 180°C limit.

ACSS has become PGE's standard advanced conductor because it offers a combination of performance, reliability, and cost effectiveness that is unmatched by other technologies:

- Proven construction performance with low installation risk
- Very high continuous and emergency temperature capability
- Large ampacity increases with predictable sag and clearance performance

J.17.2.8 High-Temperature Low-Sag Conductor

While PGE has evaluated high temperature low sag conductors in multiple conductor selection studies, no project has yet been selected and constructed one. This reflects consistent technical and economic findings:

- Lower continuous temperature capability than ACSS, requiring more aluminum area to achieve the same ampacity
- Significantly higher material and logistics costs, including spare conductor and specialized hardware.
- In some designs, lower modulus composite cores that result in greater sag under heavy ice loading, which can control clearances

Based on this experience, PGE treats high-temperature low-sag conductors as a specialized option rather than a general solution. They are most appropriate for projects with extreme physical constraints where their unique properties provide clear value, including:

- Very long spans such as major river crossings
- Retrofit applications where replacing AAC or ACSR can substantially increase capacity while minimizing the need for new structures and additional rights-of-way.

J.17.2.9 Conductor Coatings

PGE has begun incorporating advanced conductor coatings into its transmission strategy to further increase the capacity of its ACSS conductor installations. During the project scoping phase, PGE now evaluates opportunities to apply coatings at the factory for new ACSS conductors. In many cases, this approach can increase line ampacity by 10% or more without any change to conductor size, structures, or rights of way.

In parallel, PGE is also identifying existing transmission lines, primarily those constructed with ACSS conductors, where coatings can be retroactively applied using robotic systems. This approach allows PGE to unlock similar thermal and capacity gains on in service lines without the cost, outage duration, or construction impacts associated with reconductoring.

PGE views conductor coatings as a highly cost-effective grid enhancing technology that complements high temperature conductors. By reducing solar heating and improving heat dissipation, coatings allow conductors to operate at lower temperatures for a given current or to safely carry higher current within the same thermal limits. This provides a flexible and incremental pathway to increase transfer capability on both new and existing lines, helping PGE meet growing demand and integrate new resources while minimizing capital cost and system disruption.

J.17.2.10 Advanced Conductor Project Experience

As noted previously, PGE has conducted conductor selection studies on several recent large-scale transmission projects to evaluate the applicability of advanced conductors, including High-Temperature (HT) and High-Temperature Low-Sag (HTLS) technologies. The following representative projects illustrate how these conductors were analyzed and selected.

J.17.2.11 Shute to Sunset 115kV Conductor Selection Study

A project was developed to upgrade a 1.4-mile 115 kV circuit between the Shute and Sunset substations to achieve a target capacity of 3,000 amps. The existing line was originally constructed with 795 kcmil ACSS "Drake" conductor, designed for approximately 1,600 amps, and is supported by custom steel poles. Early engineering assessments determined that the use of bundled conductors would overload the existing structures.

A conductor selection study was performed to evaluate the following conductor options:

- High-Temperature Conductors
  - 1272 kcmil ACSS "Pheasant"
  - 1590 kcmil ACSS "Falcon"
  - 1780 kcmil ACSS "Chukar"
  - 2156 kcmil ACSS "Bluebird"
- High-Temperature Low-Sag Conductors
  - 1949 kcmil ACCC "Lapwing"
  - 2045 kcmil ACCC "Falcon"
  - 2741 kcmil ACCC "Bluebird"

- 1622 kcmil ACCR "Pecos"
- 1927 kcmil ACCR "Cumberland"

All conductor options were modeled in PLS-CADD using the existing structure configuration. The analysis determined that most candidate conductors would require a similar level of structural modification, and that sufficient electrical and ground clearance was available, largely due to the relatively short span lengths, to support a high-temperature conductor solution.

Based on the study results, the 2156 kcmil ACSS "Bluebird" conductor was selected. This conductor met the required ampacity, aligned with PGE standard conductor types, and has a proven performance history on similar projects in the region.

J.17.2.12 North of Pearl 230 KV Projects

PGE is implementing a reconductoring and infrastructure upgrade program for a 230 kV transmission corridor originally constructed in the 1970s. The corridor consists of a double-circuit lattice tower design and was originally built with 1272 kcmil AAC "Narcissus" conductor. The corridor spans more than 15 miles, extending from PGE's St. Mary Substation in Beaverton to BPA's Pearl Substation in Wilsonville.

The primary objective of the project is to increase the capacity of all circuits in the path while maximizing the overall capacity of the corridor. An as-built model of the existing transmission infrastructure was developed, and conductor studies were performed to evaluate 3,000 amp, 3,700 amp, and 4,000 amp operating scenarios. ACSS, ACCR, and ACCC conductor technologies were evaluated across a range of design tensions. The following conductor configurations were studied:

- 2156 kcmil ACSS "Bluebird" (High-Temperature Conductor)
- 2156 kcmil ACCC AZR TW "Bluebird" (High-Temperature Low-Sag Conductor)
- 2-bundle 1151 kcmil ACCC AZR "Arlington" (High-Temperature Low-Sag Conductor)
- 2-bundle 958 kcmil ACCR TW "Suwanee TW" (High-Temperature Low-Sag Conductor)
- 2-bundle 1033 kcmil ACCR TW "Curlew TW" (High-Temperature Low-Sag Conductor)

The study concluded that the existing lattice towers performed significantly better structurally with a single conductor configuration compared to bundled conductors. While HTLS conductors exhibited reduced sag relative to HT conductors, the difference was not sufficient to offset the structural and constructability advantages of a single conductor configuration. Additionally, the ACSS conductor provided higher overall ampacity for the evaluated scenarios.

Based on these findings, the ACSS conductor was determined to be the most suitable and cost-effective solution for the West Side 230 kV Corridor project while achieving the 4,000 Amp goal.

J.17.2.13 Mountainous Long Span 230 KV Project

PGE is in the early stages of initiating a project to upgrade an existing 230 kV transmission line supported by a lattice tower family originally developed in the 1970s. The overall design is similar to the North of Pearl 230 kV Projects; however, one segment of the line traverses mountainous terrain characterized by difficult construction access and unusually long span lengths. Also, the

target ampacity for the upgraded line is 2,800 amps, much less than the 4,000 amp target of the North of Pearl 230 KV Projects.

An as-built model of the transmission line was developed, and a conductor selection study was performed to evaluate feasible conductor options under these unique constraints. The following conductors were analyzed:

- High-Temperature Conductors
  - 1272 kcmil ACSS "Pheasant"
  - 2156 kcmil ACSS "Bluebird"
- High-Temperature Low-Sag Conductors
  - 2741 kcmil ACCC "Bluebird"
  - 2045 kcmil ACCC "Falcon"
  - 1962 kcmil ACCR "T11"

This project is currently in the early scoping and preliminary design phase and is not as mature as the previously discussed examples. However, preliminary results indicate that the long spans and limited constructability make structure replacement highly undesirable. As a result, a high-strength HTLS conductor appears to be the preferred solution for achieving the required ampacity while avoiding tower replacement.

Notably, the lattice towers located in the mountainous segment are unique dead-end structures with higher-than-typical strength ratings. This allows the project to take advantage of the high-strength composite core of the 1927 kcmil ACCR "Cumberland TW" conductor by increasing conductor tension. Doing so reduces sag sufficiently to maintain required clearances across long spans, enabling the upgrade to meet thermal and mechanical requirements without modifying or replacing existing towers.

J.17.2.14 Conductor Coatings

PGE has initiated a pilot program to deploy advanced conductor coatings on select 230 kV transmission projects to maximize line ampacity. The first application of this technology will occur on the 1.5 Mile Horizon–Keeler #1 230 kV line, where Prysmian will apply the E3X coating at the factory during manufacturing of the 2156 kcmil ACSS (84AL/19S) "Bluebird" high-temperature conductor. The E3X-coated conductor will enable the Horizon–Keeler #1 line to achieve a design ampacity of 4,000 amps. The coated conductor is currently onsite and is scheduled for installation in spring 2026.

Following the reconductoring of Horizon–Keeler #1 230 kV to a 4,000-amp standard, PGE plans to apply conductor coating to the parallel, in-service Horizon–Keeler #2 230 kV line using a robotic application system. This line currently utilizes 2156 kcmil ACSS (84AL/19S) "Bluebird" high-temperature conductor. Retrofitting the existing conductor with a coating will allow PGE to further maximize system ampacity.

Another planned application of conductor coatings is on a 3.8-mile segment of the Evergreen–St. Marys–Trojan 230 kV line. This section currently consists of 1272 kcmil ACSS (54AL/19S) "Pheasant"

conductor and will be re-rated to a maximum operating temperature of 250°C. To achieve the project's target ampacity of 2,800 amps, a conductor coating will be applied to the existing conductor using a robotic system.

Based on the experience gained from these initial applications, several additional projects currently in development are considering or planning to procure factory-applied coated conductors. These potential projects include:

- Reconductoring of the Murrayhill–Sherwood #1 and #2 230 kV lines (approximately 5.5 miles each)
- Reconductoring of the Murrayhill–St. Marys 230 kV line and construction of a new section of the St. Marys–Sherwood 230 kV line (approximately 5.2 miles each)

PGE is also evaluating the use of conductor coatings as a non-wire-replacement solution on portions of the 115 kV system. For locations where planning studies identify only minor thermal overloads, conductor coatings may serve as an initial mitigation strategy prior to initiating full reconductoring projects.

J.18 Topology Optimization

J.18.1 Overview

- Explanation of general topology optimization approaches
- Explanation of Remedial Action Schemes (generally deployed across PGE's system; details are CEII)
- McLoughlin V248 Breaker Replacement project
- List of reconductor projects that have been delayed/avoided with this project

Topology Optimization is a tool used in real-time operations to adjust flows on the transmission system. This is typically accomplished by either (1) opening or closing circuit breakers to re-route power flows or (2) redispatching generation to prevent overloads to certain parts of the power system.

PGE utilizes topology optimization in daily operations today. PGE Grid Operations engineers are responsible for identifying credible contingencies (such as loss of generation, outages to transmission lines, etc.) and developing operating plans that mitigate negative impacts to the grid under these circumstances. These operating plans often include steps such as opening/closing circuit breakers, or redispatching specific generation, in order to prevent overloads on the transmission system.

In addition to manual operator action, there are also automated schemes that can be installed at substations to prevent issues that have been consistently identified in long-term studies. These automated solutions are referred to as Remedial Action Schemes (RAS). They are triggered automatically under certain grid conditions. These RAS provide operators the ability to operate the grid in pre-contingency state that is close to causing system issues, with the understanding that the post-contingency state will trigger RAS action that mitigates system concerns. Figure 209,

Figure 210, and Figure 211, provided in a BPA presentation,[305] demonstrate the general operation of a RAS scheme.

Figure 209. Pre-contingency, the System Operates with All Lines In-Service and No Overloads

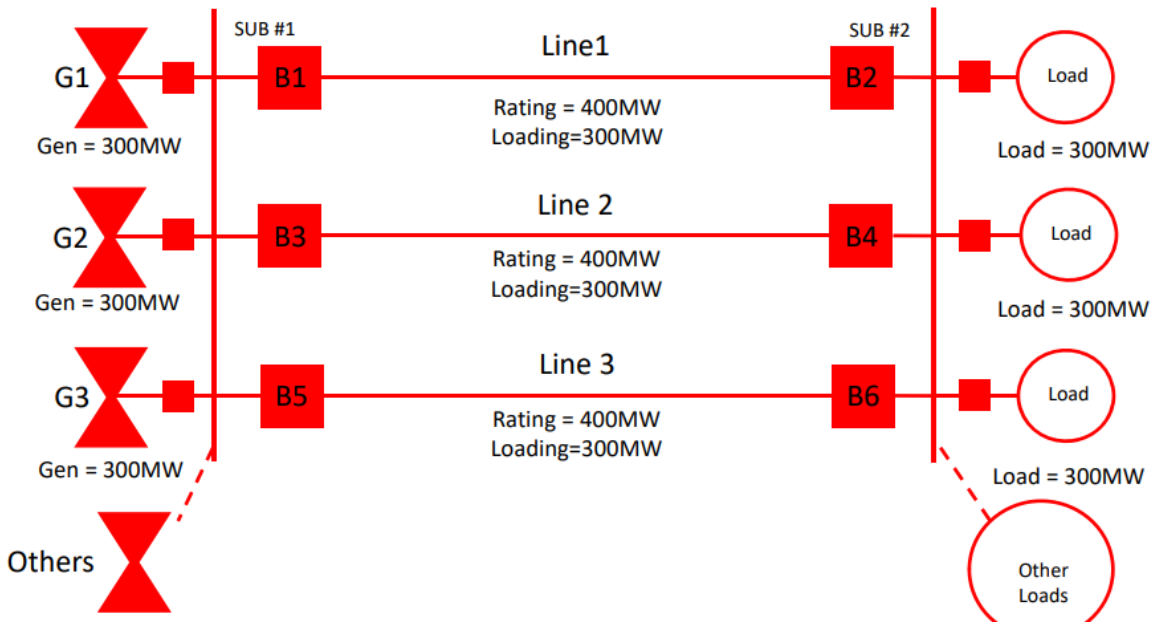
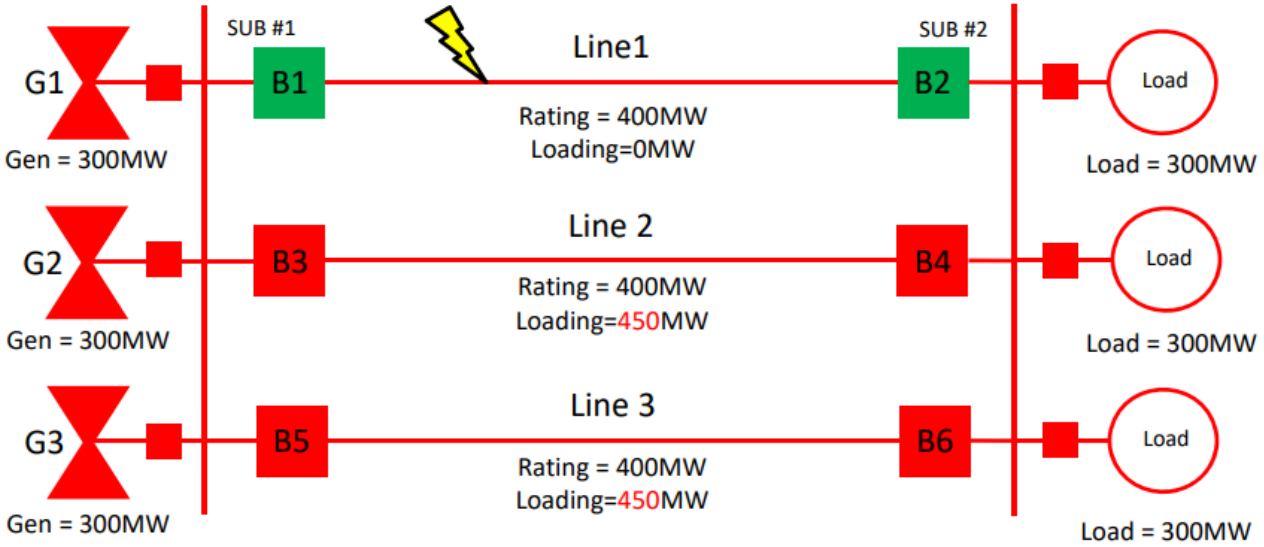
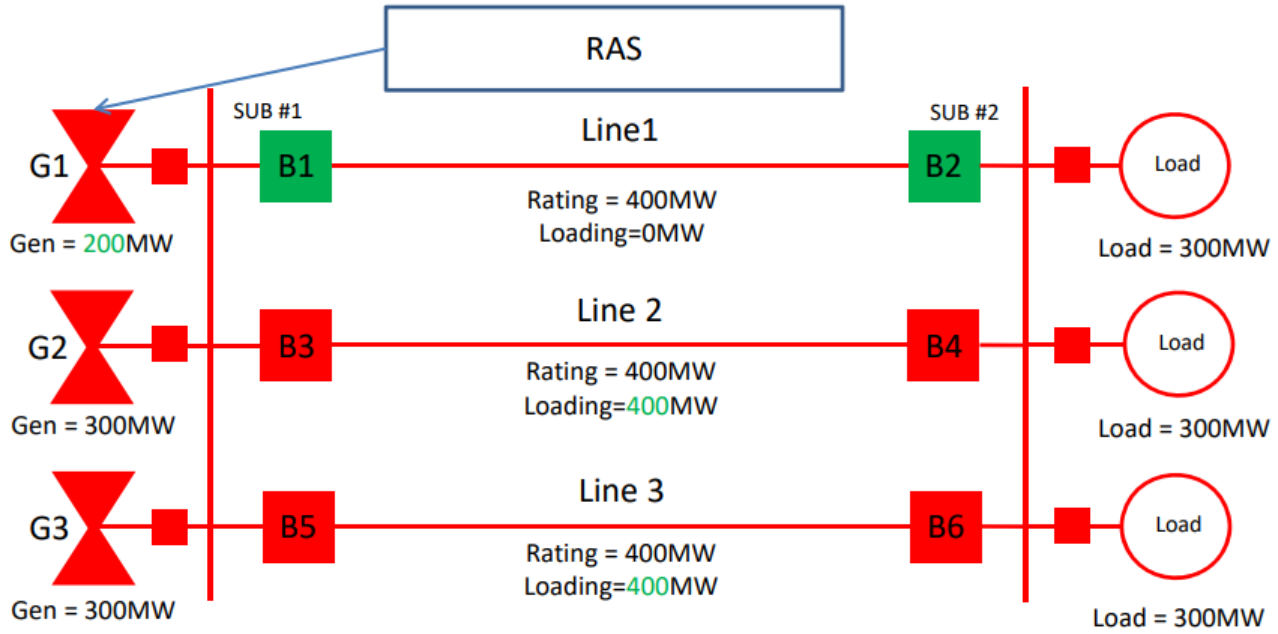


Figure 210. A Contingency (Fault) Has Occurred on Line 1, Resulting in Increased Power Flowing on Line 2 & 3, Overloading Both Transmission Lines.



[305] https://na.eventscloud.com/file_uploads/e7ab2600bdc1e8a7d8dd14b9d7195c35_RemedialActionSchemesforHands-OnRelaySchool2018ASPRESENTED.pdf

Figure 211. A Remedial Action Scheme (RAS) Automatically Operates to Reduce Generation at Generator G1, Preventing Overloads on Line 2 &3.



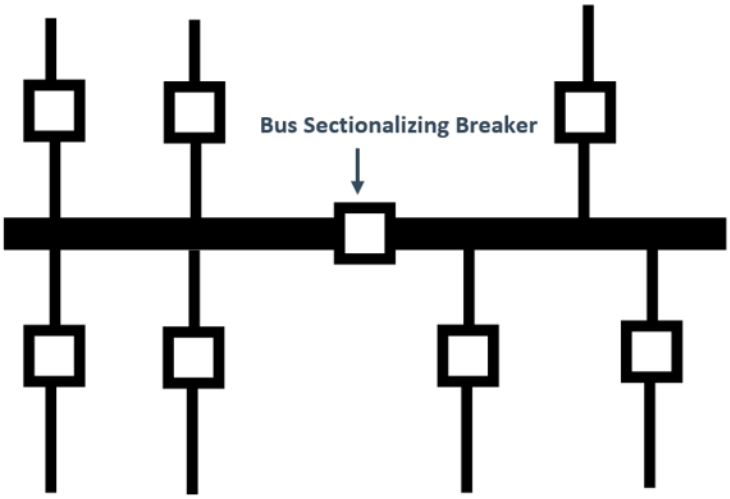
PGE has installed RAS setups at multiple locations on its system, both to protect internal PGE assets, as well as to coordinate actions with neighboring BPA and PacifiCorp infrastructure. While the details of RAS implementation are generally considered Critical Energy Infrastructure Information (CEII) and not available to be shared publicly, PGE does assert that it considers RAS actions as part of all new transmission planning studies, as well as when evaluating the potential to increase generation utilization across the Pacific Northwest.

J.18.2 McLoughlin Circuit Breaker Replacement Project

In general, PGE uses Topology Optimization to best utilize the existing transmission system. Recently, PGE identified an issue at an existing substation that prevented the ability to fully utilize topology optimization.

PGE's McLoughlin substation has a bus sectionalizing breaker (BSB) included in the substation. The topology of a BSB design is shown below in Figure 212.

Figure 212. General Topology of a Substation with a Bus Sectionalizing Breaker Arrangement



In general, BSBs can be opened or closed depending on transmission system needs, and this operation can have a large impact on power flows in the local area. However, the McLoughlin substation contained a legacy oil circuit breaker which had a lower fault duty rating, which prevented the closure of the McLoughlin BSB under most system conditions. This limitation was identified and, in 2025, the project P39043 was completed to replace the McLoughlin oil breaker with a more modern breaker that had a higher fault duty rating.

Since the replacement, PGE Operations now has the ability to open or close the McLoughlin BSB as needed to address varying system conditions. Planning studies indicate that this project provided the ability to defer more expensive 115kV reconductor projects in the Oregon City area.

J.18.3 Dynamic Line Ratings

A transmission line conductor's thermal limits (or ampacity) are determined based on the maximum operating temperature of the conductor that prevents premature aging and that limits conductor sag to maintain minimum clearances under the line for safety. Conductors expand at higher temperatures, lengthening the line and reducing the distance to the ground and other objects, which can result in arcing or faults if safe clearance distances are not maintained.[306]

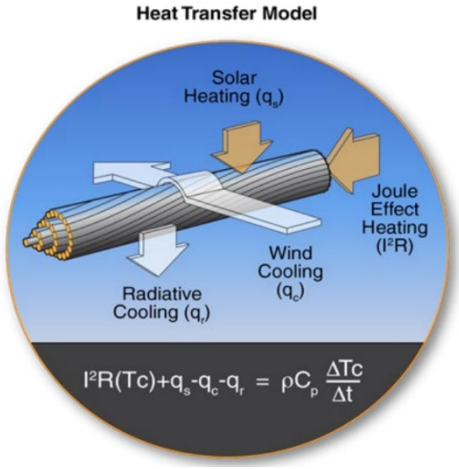
Conductor ampacity is obtained through the use of a Heat Transfer Model, accounting for the balance of the Joule Heating Effect (due to electrical current passing through the conductor), the Solar Heating, the Radiative Cooling, and the Wind or Convective Cooling. The two (2) widely used models are described in the IEEE 738 and the CIGRE TB 601 Standards, the first being more common in North America, and the later in Europe.

The physical properties of the conductor, (e.g., the maximum operating temperature, electrical resistance, conductor size), combined with a set of weather/environmental conditions (e.g., ambient temperature, wind speed and direction, solar radiation) are used to calculate the thermal limits.

[306] DOE, Dynamic Line Rating. Available at: https://www.energy.gov/oe/articles/dynamic-line-rating-report-congress-june-2019

Static Line Rating (SLR) are developed by assuming specific static weather/ambient conditions (for example, wind speed of 3 miles per hour or ambient temperature of 85°F). Figure 213 presents the heat transfer model used to obtain the conductor's ampacity.

Figure 213.[307] Heat-Transfer Model for an Overhead Conductor



There are many different technologies and methodologies to determine the Dynamic Line Ratings (DLR) of an overhead conductor; but in principle, DLR uses the same heat-balance equations as SLR, with the addition of real-time sensor information, taking into account the conductor heat inertia, and more granular weather information. DLR technologies are subdivided in weather-station based or sensor-based systems: the first either measures or receives from a weather provider the direct inputs to the heat balance equations. The second is focused on collecting field-data directly from the conductor itself, establishing relationships between those measurements and the conductor ampacity.

J.18.4 PGE Dynamic Line Ratings Project

Following FERC's announcement of an Advance Notice of Proposed Rulemaking (ANOPR) in Docket No. RM24-6, which seeks comments from PGE and other utilities on requiring the use of Dynamic Line Ratings (DLRs), PGE is preparing for anticipated changes that may require DLRs in the future. Beginning in 2025, PGE implemented DLRs and develop a broader plan to expand this technology across its transmission system. This effort is aimed at reducing congestion costs, improving renewable integration, and increasing overall system capacity and reliability.

With over 40 sensors already installed and six (6) activated lines, PGE plans to install more than 50 sensors and activate additional eight (8) transmission lines in its service territory. Overview maps of the activated PGE DLR lines for the Portland and Salem areas are presented in Figure 214 and Figure 215, respectively.

[307] Image from same DOE reference as previous footnote

Figure 214. Map of the currently activated PGE DLR lines in the Portland area.

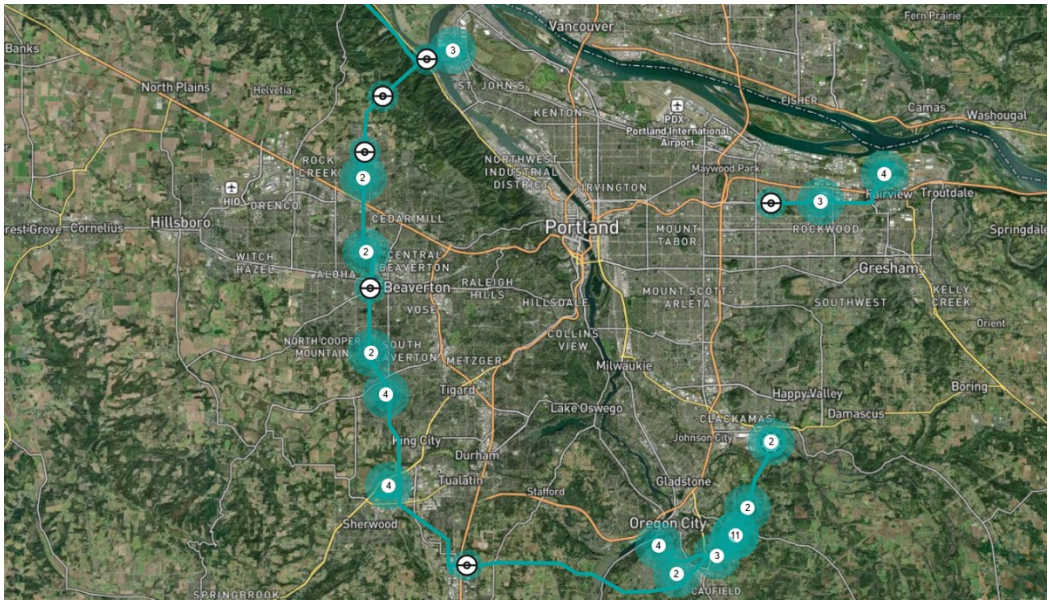
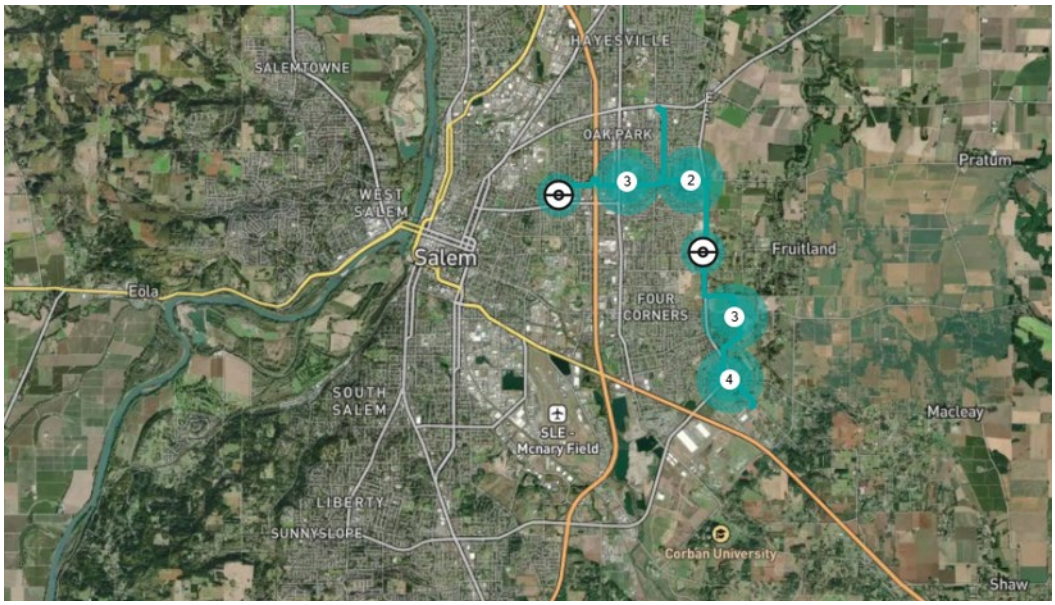


Figure 215. Map of the currently activated PGE DLR lines in the Salem area.



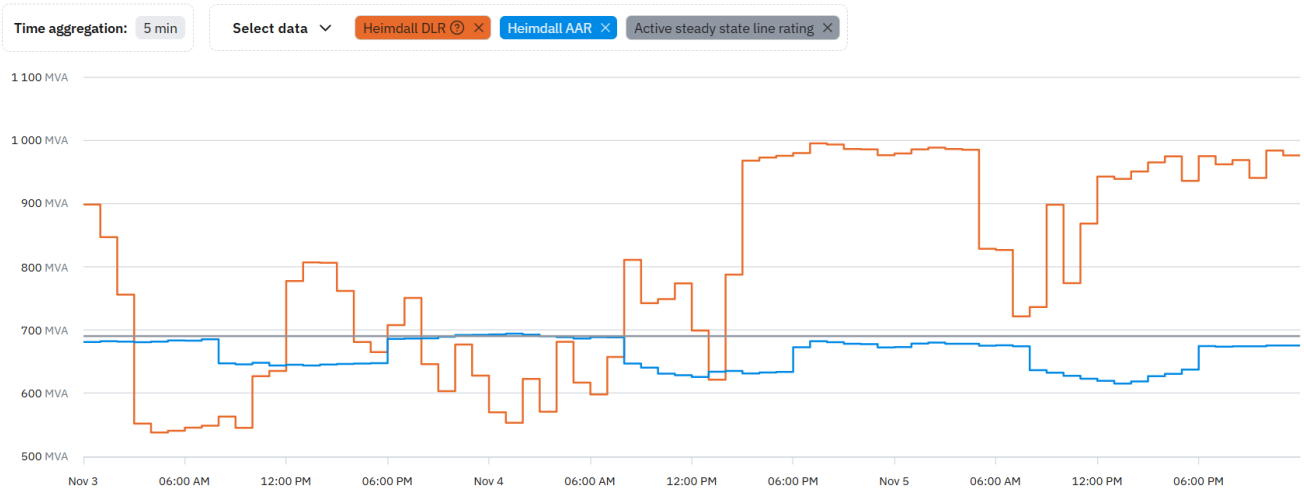
J.18.5 Overview of Collected Data To-date

PGE is actively conducting comprehensive data analysis and performance evaluations of the DLR sensors. A primary focus of this work is quantifying the capacity gains achieved by comparing DLR values against Ambient Adjusted Ratings (AAR), in which all inputs remain fixed except for dynamically varying the ambient temperature.

The initial phase of these studies centered on validating sensor configurations and parameters, followed by establishing benchmarks relative to AAR and existing Line Seasonal Ratings.

Although the pilot line began collecting data in April 2025, additional data is required before PGE can draw confident conclusions about the full benefits and operational value that DLR may provide to the system. Figure 216 presents an example of the DLR, AAR, and static line rating for line A-B[308] during the November 3rd to 6th.

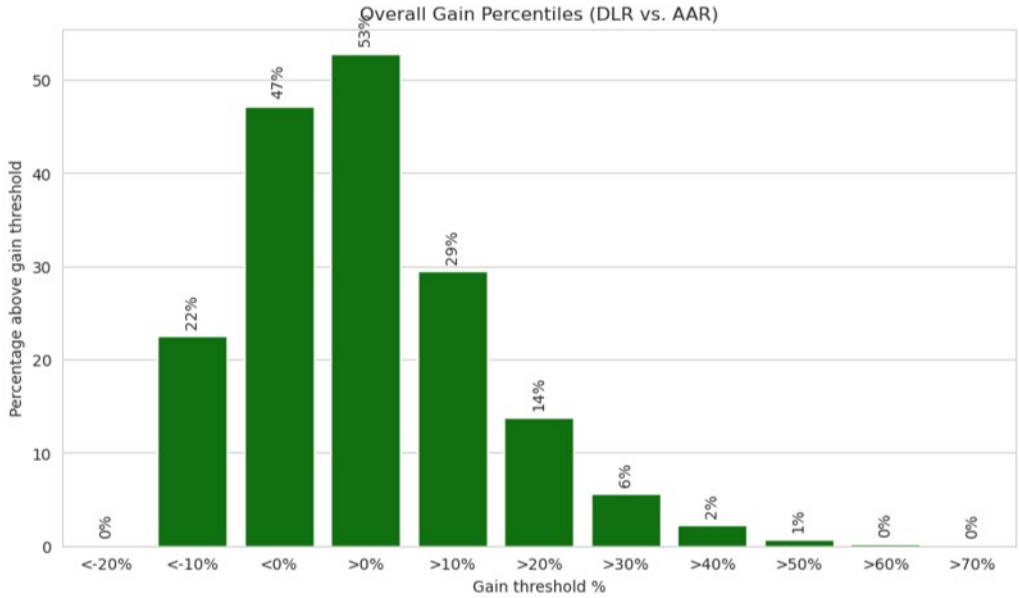
Figure 216. DLR, AAR, and Static Line Rating for the line A-B7 during November 3rd to 6th (DLR - orange, AAR - blue, and Static - grey).



PGE has completed a series of preliminary analyses assessing capacity increases or decreases across multiple rating methodologies under a range of observed weather conditions (e.g., Blue Sky days, High Heat days). Figure 217 presents the preliminary overall gain percentiles when comparing DLR and AAR, for line A-B, from the months of June to October 2025. A positive gain means that DLR had a higher value than AARs and vice-versa.

[308] The Line A-B name is redacted to comply with FERC Critical Energy Infrastructure Information policy.

Figure 217. DLR vs AAR Overall Gain Percentiles, from June to October 2025.



Although the DLR reached gains as high as 50% over the AARs, the DLRs only had a positive gain over AARs during 53% of the sample time periods. Additional data is required before PGE can draw confident conclusions about the full benefits and operational value that DLR may provide to the system.

J.18.6 Next Steps

PGE will continue to collect data and analyze the impact of operationalizing DLRs across its service territory. After the completion of Sensors Installation & EMS Integration of all 14 Transmission Lines, PGE intends to integrate the technology for day-to-day operations usage.

Figure 218. PGE Lineman Installing a DLR Sensor Using the "Hotstick" Method

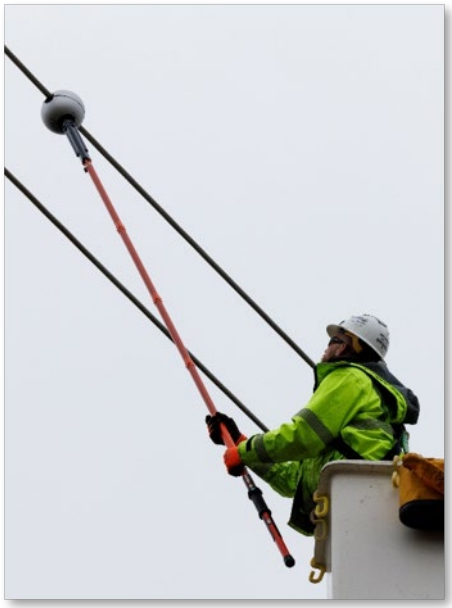


Figure 219. PGE Drone Installing a DLR Sensor

Figure 220. PGE Crews after Installing a DLR Sensor (top right in picture) Using a Drone

J.19 Power Flow Control Devices

The term Power Flow Control Devices describes a range of equipment that is installed on the transmission system for the purposes of pushing or pulling power from one area to another. This category includes a range of devices.

Traditional power flow control devices include shunt capacitors and shunt reactors, which provide operators a way to raise or lower the voltage at a specific substation, respectively. PGE deploys these devices across its service territory.

Other traditional power flow control devices include series reactors, which are typically installed on long (50+ mile) transmission paths, in order to maximize the flows across these paths. PGE deploys these devices on the 500kV transmission paths that it co-owns in the region.

More recent, advanced power flow control devices utilize power electronic switching to achieve more granular control of the power system. These include devices such as static var compensators, STATCOMs, and static synchronous series compensators. The use of these devices tends to be more targeted, as they provide significant grid benefits, but also tend to include higher price tags. They are used, for example, in areas where voltage instabilities have been observed, or in areas that

require the ability to "push" or "pull" power dynamically and in an automated fashion, without operator input.

PGE recently worked with the Electric Power Research Institute (EPRI) to evaluate the use of advanced power flow control devices for several areas where transmission solutions were proposed. Utilizing EPRI's "Controlled Transmission Expansion Planning" (CPLANET) tool, PGE evaluated the impact of adding these devices to the grid, and the cost impacts versus more traditional, wired solutions. PGE did not identify any case in which the advanced power flow control devices provided a more cost-effective solution than the proposed transmission project. PGE expects to expand on this analysis with future transmission studies.

J.19.1 High-Voltage Direct Current (HVDC) lines

High-voltage direct-current lines have existed on the power system since the 1960's. They typically are deployed in situations where power needs to be transferred across a very long distance. For example, the Pacific DC Intertie was constructed in the 1960's by BPA and Los Angeles Dept. of Water and Power, to send power directly from The Dalles, Oregon, to Southern California.

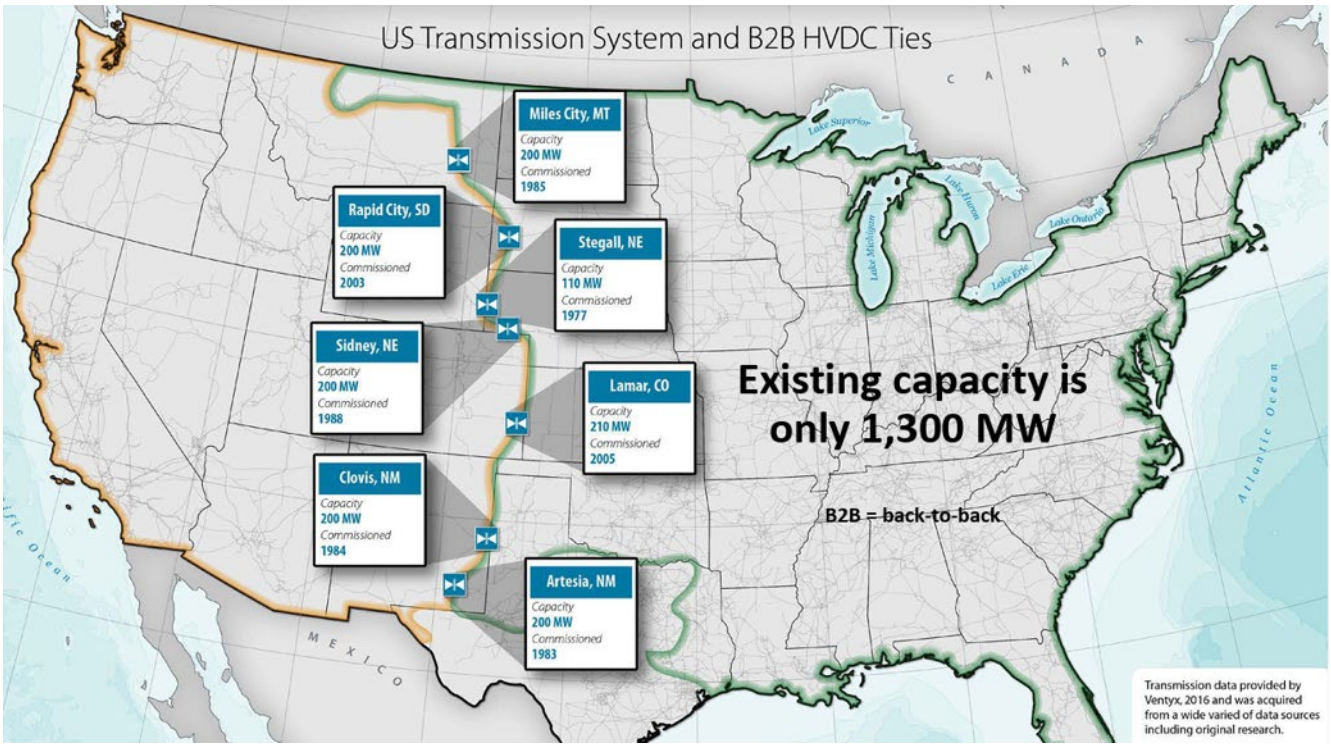
Given the tremendous cost of AC-DC converter stations (hundreds of millions of dollars), as well as the large physical footprint of these facilities, this technology is utilized most often for large-scale, long-distance applications. Using DC lines to send power within the Portland metro area, for example, would not be practical, due to the excessive cost of DC converter stations compared to the more traditional AC transmission line approach.

PGE does evaluate the use of HVDC lines for larger projects. For example, the Warm Spring Power Pathway project, which will convert PGE's existing Bethel-Round Butte 230kV transmission line into a 500kV transmission line, was evaluated for both AC and DC topologies. It was determined that the increased cost of DC converter equipment would not be justified in that specific situation.

PGE is also actively considering more regional transmission solutions that utilize DC architecture. PGE is involved with the proposed North Plains Connector project, which would construct a new DC transmission line that connects the Western and Eastern Interconnections, providing up to 3000 MW of transfer capability between regions. Since the Western and Eastern grids are separated

today, the only way to connect them together is with DC transmission links. This project is discussed further in Chapter 5.

Figure 221. Map Showing the Three (3) Existing Synchronous US Transmission Grids[309] (Western Intertie, Eastern Intertie, and Texas Intertie) and Existing DC Connections Between Western and Eastern Systems



Today, there is only 1.3 GW of existing transfer capacity between west and east, compared to 200 GW of peak load in the Western grid, and 600 GW of peak load in the Eastern grid. Projects like the proposed North Plains Connector would increase the transfer capability between regions, providing PGE access to additional generation markets.

J.19.2 Batteries as a Transmission Asset

Energy storage serves important grid functions, including time-shifting energy across hours or days; regulating grid frequency; and ensuring flexibility to balance supply and demand. Energy storage is particularly important in an increasingly electrified world where demand is rising and supply is shifting toward variable renewables, increasing the need for dispatchable energy. BESS facilities can also, in specific situations, provide reliability benefits by reducing flows on overloaded distribution or transmission lines.

PGE currently owns and operates several smaller BESS in the 1 to 20 MW range across its service territory, as well as three large BESS that total 475 MW of capacity. These batteries are used for a

[309] From the NREL "Interconnection Seam Study" - https://docs.nrel.gov/docs/fy21osti/78161.pdf

variety of grid services mentioned above, in particular frequency regulation and time-shifting of energy.

In order to use a BESS to mitigate a transmission overload, two (2) conditions must be met. First, the battery must interconnect at a point on the system such that its discharge (or in certain situations, its charge) causes a significant reduction in the loading on the potentially overloaded line. Second, the battery must be sized with adequate energy to offset the overload for the duration of the outage. Given uncertainty around outage times (which can vary from under two (2) hours to up to three (3) days depending on system conditions, weather, crew availability, etc.), the exact size requirement is usually expressed as a function of the expected outage time.

A major limitation of using BESS as a transmission asset is that a theoretical battery solution could only be discharged to address the identified system overloads and would have to be on stand-by at near-full or full charge at all other times to address a potential future overload. Thus, utilizing batteries as a transmission asset precludes them from providing most other grid services. For example, because the battery is being used to prevent a potential overload and must remain at or near full charge waiting for an outage to occur, it cannot participate in valuable grid service activities, such as energy shifting. This reduces the value of other services that the battery could otherwise provide to the system and makes the battery solution inefficient and ineffective and makes the cost/benefit case for a "storage as a transmission asset approach" much more challenging.

Moreover, the inherent inefficiency of using a battery in this way is magnified by the high cost of a BESS solution. Recent PGE BESS projects resulted in an average of $450/kWh for transmission-sized batteries. To put this in context, battery storage as an asset was analysis during the Tonquin CPN 6[310] testimony. In that case, analysis of the cost of the BESS solution to adequately address identified overloads was estimated to exceed $200 million. This cost estimate was over 10 times more than the direct costs for the proposed transmission solution in that case.

PGE will continue to evaluate instances where battery storage assets can potentially alleviate system overloads. This begins by assessing whether the existing BESS assets on PGE's system can be redispatched to alleviate certain overloads. Failing that, the cost of installing new, dedicated storage resources will also be assessed, in order to compare against proposed transmission solutions.

[310] CPN 6, Supplemental Testimony 600-604

Appendix K Long Term Transmission Options

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.

K.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. 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 2026 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 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 10-year time horizon.

K.2 Local Transmission Results

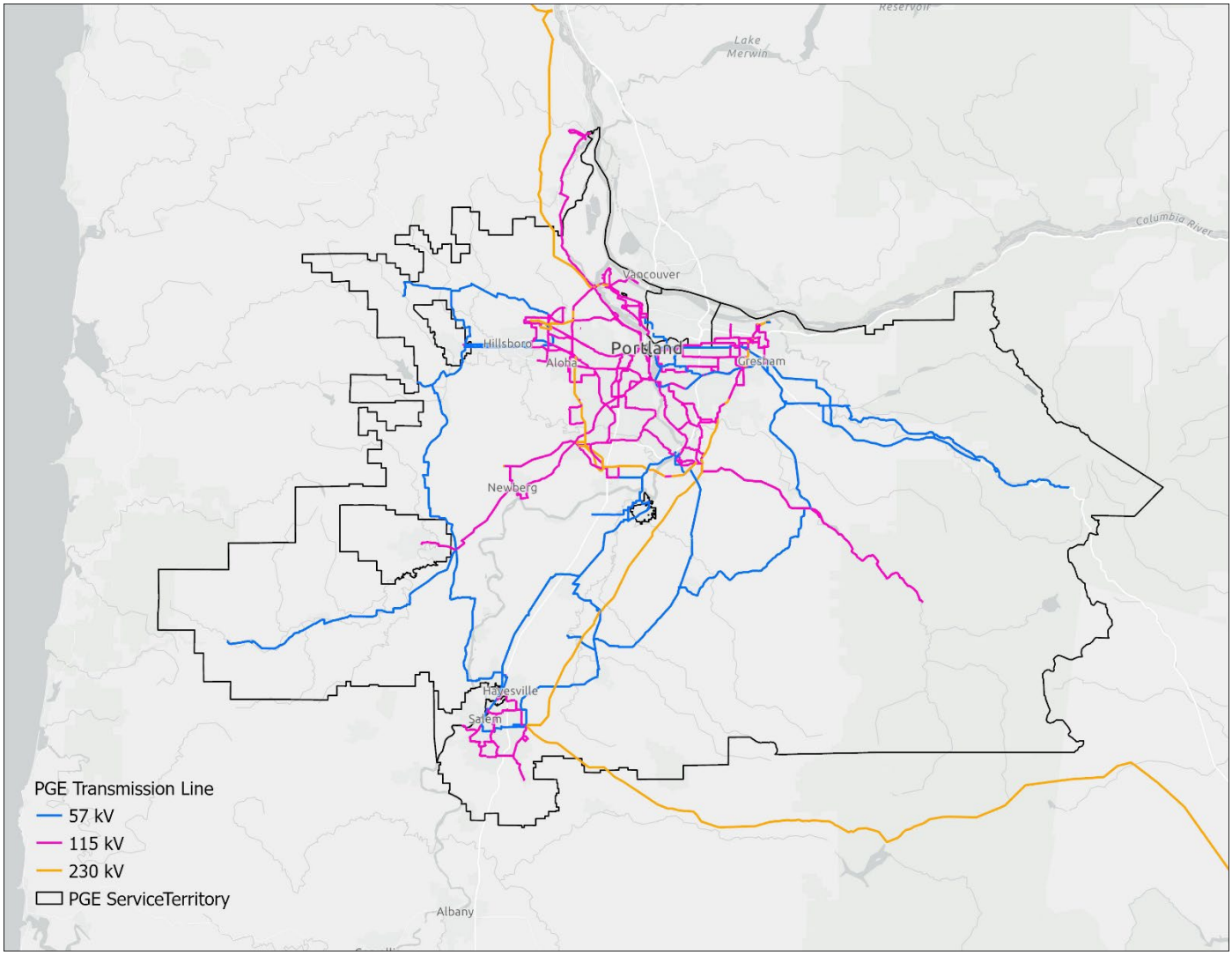
K.2.1 PGE Transmission Projects

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 2025 include:

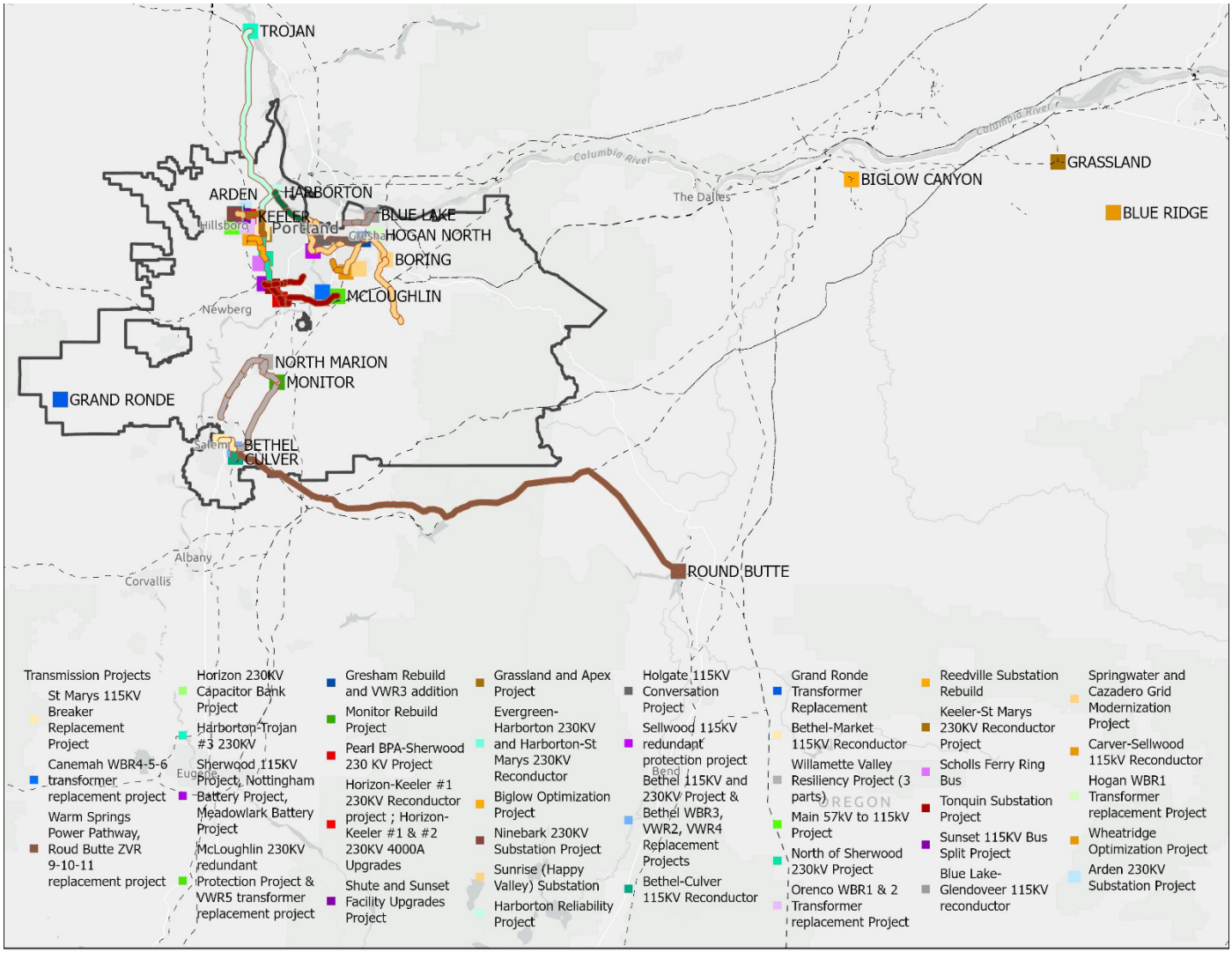
- Installed 105 dynamic line rating sensors on 14 transmission lines and integrated them into the energy management system (EMS).
- Energized one (1) new substation, added distribution capacity to one (1) existing substation, and completed rebuilds and reconfigurations of three (3) transmission lines for capacity and reliability:
- Memorial substation (energized 5/28/25)
- Evergreen substation phase 3 – new distribution infrastructure (In-service 12/23/25)
- South Milliken 57 kV transmission rebuild of Faraday – Estacada line section (in-service 10/09/25)
- South Milliken 57 kV transmission rebuild of Estacada – River Mill line section (in-service 12/19/25)
- Pearl – Sherwood #1 & #2 230 kV transmission line – co-owned with BPA
- Pearl-Sherwood #1 (energized 12/19/25)
- Pearl-Sherwood #2 (energized 1/15/26)

Figure 222. Existing PGE Transmission System - Transmission Lines



PGE revisits transmission plans and projects on a specific time cadence, with those in Table 110 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.

Figure 223. Existing PGE Transmission System - Transmission Projects



K.3 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. PGE's GETs strategy is described in detail in Appendix J.

K.3.1 Transmission Reliability Projects

Below is a list of projects identified in PGE's Local Transmission Plan process, which are required Corrective Action Plans to maintain transmission system reliability.

Table 110. Transmission Projects

Project Name	Project Completion Date
Horizon-Keeler #1 230kV Reconductor Project	April, 2026
Monitor Rebuild Project	November, 2026
Pearl BPA-Sherwood 230 kV Project	November, 2026
Grand Ronde Transformer Replacement	March, 2027
Shute and Sunset Facility Upgrades Project	March, 2027
Sunset 115kV Bus Split Project	April, 2027
Tonquin Substation Project	April, 2027
Harborton Reliability Project	April, 2028[311]
North of Sherwood 230kV Project	May, 2028
St Marys 115kV Breaker Replacement Project	May, 2028
Bethel-Culver 115kV Reconductor	June, 2028
Hogan WBR1 Transformer replacement Project	September, 2028
Holgate 115kV Conversion Project	September, 2028
Orenco WBR1 Transformer replacement Project	September, 2028
Orenco WBR2 Transformer replacement Project	September, 2028
Bethel 115kV Project	March, 2029
Sherwood 115kV Project	March, 2029
Horizon-Keeler #1 & #2 230kV 4000A Upgrades	April, 2029
Bethel-Market 115kV Reconductor	June, 2029
Springwater and Cazadero Grid Modernization Project	September, 2029
Bethel WBR3 transformer replacement Project	December, 2029
Reedville Substation Rebuild	January, 2030
Carver-Sellwood 115kV Reconductor	April, 2030
Sellwood 115kV redundant protection project	April, 2030
Keeler-St Marys 230kV Reconductor Project	June, 2030
Bethel VWR2 Replacement	January, 2031

[311] Harborton Reliability Project is currently scheduled for a 2028 in-service date. Due to ongoing permitting challenges with the project, a delay to the in-service date to 2031 was modeled in this year's transmission models, in order to quantify the impacts of not completing this work by the 2028 need date. The modeled delay identified contingencies that would result in overloads to the transmission system which can only be alleviated via customer load shed actions until the Harborton Reliability Project is completed.

Project Name	Project Completion Date
Scholls Ferry Ring Bus	January, 2031
Bethel 230kV Project	April, 2031
Horizon 230kV Capacitor Bank Project	April, 2031
Sunrise (Happy Valley) Substation	April, 2031
McLoughlin VWR5 transformer replacement project	September, 2031
Round Butte ZVR9-10-11 Replacement	March, 2032
Warm Springs Power Pathway[312]	March, 2032
Arden 230kV Substation Project	April, 2032
Evergreen-Harborton 230kV and Harborton-St Marys 230kV Reconductor	April, 2032
Gresham Rebuild and VWR3 addition	April, 2032
Main 57kV to 115kV Project	April, 2032
Ninebark 230kV Substation Project	April, 2032
Willamette Valley Resiliency Project (3 parts)	February, 2033
Bethel VWR4 transformer replacement project	September, 2033
Canemah WBR4-5-6 transformer replacement project	September, 2033

K.3.2 Large Generation Interconnection and Renewable Access Projects

Table 111 contains a list of projects that are required to fulfill FERC Large Generation Interconnection requests, Line and Load Requests, and/or to provide PGE with regional access to generation resources.

Table 111. FERC Large Generation Interconnection Request Projects

Project Name	Project Completion Date
Biglow Optimization Project	December, 2027
Blue Lake-Glendoveer 115kV reconductor	March, 2027
Grassland and Apex Project	October, 2026
Warm Springs Power Pathway[313]	March, 2032
Harborton-Trojan #3 230kV	April, 2035
Meadowlark Battery Project	November, 2027
Nottingham Battery Project	April, 2028
Wheatridge Optimization Project	December, 2027

[312] Note that Warm Springs Power Pathway addresses both NERC reliability concerns and provides regional generation access, and is listed in both lists of projects.
[313] Note that Warm Springs Power Pathway addresses both NERC reliability concerns and provides regional generation access, and is listed in both lists of projects.

K.4 BPA and Pacific Northwest Transmission System

BPA is a federal power marketing administration (PMA) that operates approximately 75% 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.[314]

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 associated with the contract on a long-term basis. BPA's primary vehicle for transmission reinforcement since 2013 has been the Transmission Service Request Study and Expansion Process (TSEP), designed to identify individual commercial expansion projects on BPA's internal Network (defined as those portions of BPA's transmission system that do not include the Montana Intertie, Northwest AC Intertie (NWACI), nor Pacific DC intertie (PDCI)) and targeted reinforcements in response to specific customer needs. The last TSEP study was completed in 2023 and BPA announced a pause in February 2025 to allow redesign intended to accommodate a larger volume of customer requests. As discussed by BPA and stakeholders throughout BPA's Grid Access Transformation Project (GAT),[315] 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.

K.5 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. Off-system resources require transmission to PGE's service territory to be selected in portfolio analysis. A limited quantity of resources can be added using quantities of existing available long-term and short-term transmission rights.

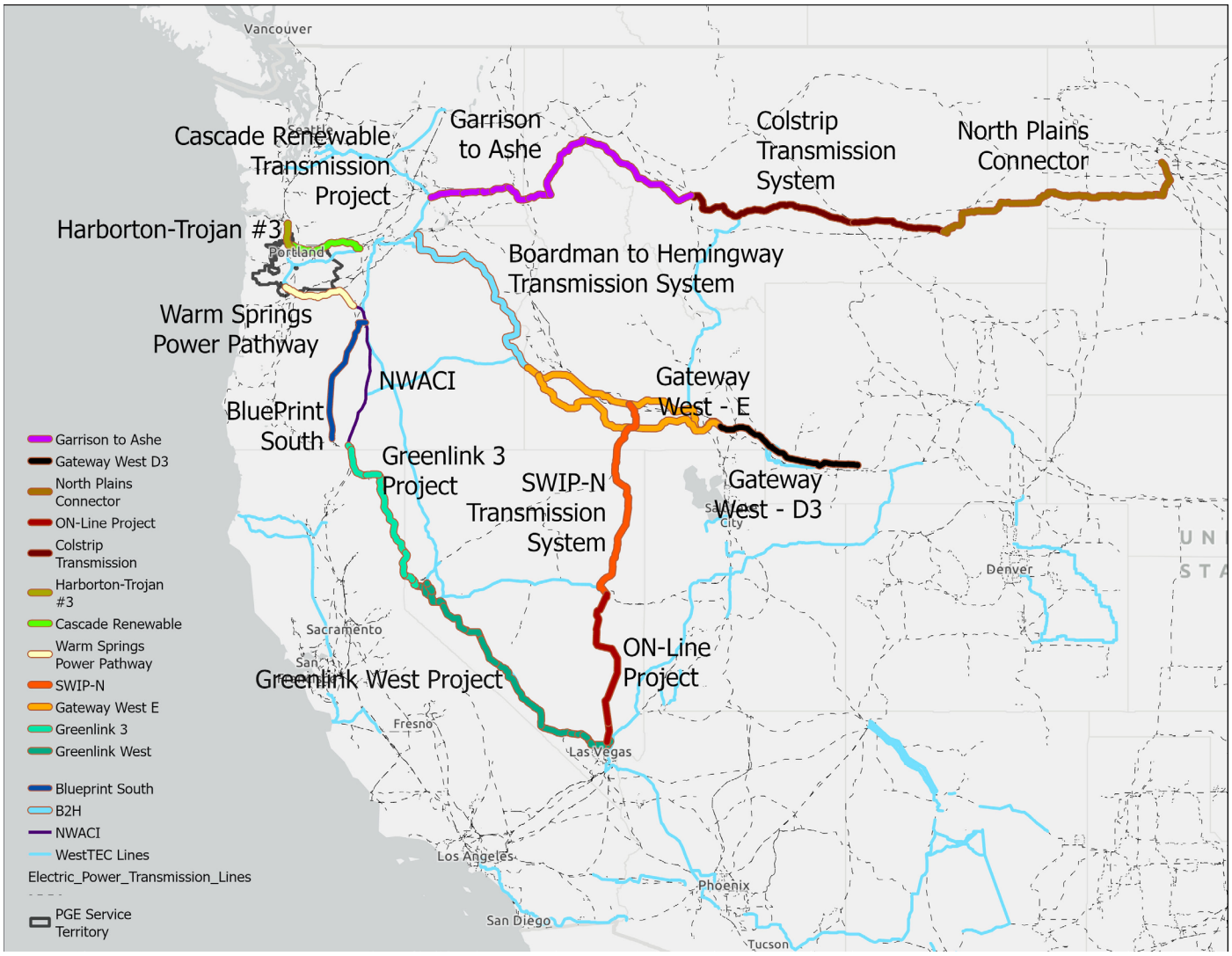
The 2026 CEP/IRP incorporates estimates from PGE's 2025 All-Source RFP regarding the quantity of existing long-term transmission rights deliverable to PGE. Bids included in PGE's RFP initial shortlist included transmission service plans from BPA for 1570 MW of incremental long-term transmission available transfer capacity (ATC) to deliver energy to PGE's service territory without expansion investments required from PGE.[316] The majority of the service plans were conditional on completion of BPA upgrades including Big Eddy-Chemawa and Ostrander-Pearl. Importantly, several of these transmission capacity reservations require redirects to either reach a generation point of receipt—a process that BPA has suspended.

[314] BPA transmission system: https://www.bpa.gov/-/media/Aep/about/publications/maps/bpa-transmissionlines-and-facilities.pdf .
[315] Grid Access Transformation Project - Bonneville Power Administration https://www.bpa.gov/energy-and-services/transmission/grid-access-transformation-project
[316] See PGE's 2025 RFP Final Shortlist filing, p8: https://edocs.puc.state.or.us/efdocs/HAH/um2371hah345181028.pdf

K.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 5.1.1) 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.

Figure 224. Overview of PGE Transmission Options



K.6.1 Warm Springs Power Pathway Upgrade

The Warm Springs Power Pathway (WSPP), jointly coordinated by the Confederated Tribes of Warm Springs (CTWS) and Portland General Electric (PGE), is a major transmission infrastructure project designed to increase power transfer capability between Central Oregon and the Willamette Valley. The project proposes rebuilding and upgrading the existing approximately 100-mile Bethel-Round Butte transmission line from 230kV to 500kV, This project includes:

- Decommissioning the existing Bethel–Round Butte 230 kV transmission line.
- Rebuilding the 230 kV transmission line from PGE's existing Bethel Substation near Salem, Oregon to a new "Lambert" 500 kV Substation near Sublimity, Oregon in the Willamette Valley. Rebuilding the corridor as a new 500 kV transmission line from the new Lambert Substation to new Mountain View Switchyard near Madras, Oregon. Bethel to Lambert will be rebuilt as a dual circuit 230kV line.
- Installing new high-capacity fiber-optic cables along the entire transmission route to provide enhanced system protection, regional communications resiliency for transmission system protection and operations, and enhanced broadband services to underserved areas with internet partners.
- Constructing new 500 kV substation facilities at the termination points for interconnection into the transmission network, including future space for potential Tribal solar interconnection.
- Reinforcing existing transmission facilities at both termination points to allow greater energy transfer with the new transmission line.

By leveraging an existing transmission corridor and right-of-way, the project significantly reduces siting, permitting, environmental, and community impacts relative to a greenfield transmission development.

The WSPP will create a high-capacity transmission pathway connecting generation-rich resource areas east of the Cascades with growing load centers in PGE's service territory within the Willamette Valley. The project is expected to provide approximately ~2,000 MW of incremental import capability into the PGE's system under the currently funded single-circuit configuration, enabling access to a broader portfolio of diverse, and cost-effective regional energy resources.

In addition to supporting customer load growth, the project will improve overall grid reliability, operational flexibility, and regional transmission efficiency. WSPP will significantly increase transfer capability across the region and help relieve congestion associated with Bonneville Power Administration's (BPA) West of Cascades transmission constraints. The project also enhances system resilience by increasing bidirectional transfer capability, allowing power to be moved more effectively between eastern and western Oregon during extreme weather events, generation outages, transmission disruptions, and other emergency operating conditions.

K.6.1.1 Need for the Project

Recent transmission planning studies have also demonstrated that WSPP is necessary to maintain system reliability. PGE's 2025 Local Transmission Plan studies identified reliability concerns

associated with the existing Bethel-Round Butte 230kV transmission line. Five-year and ten-year reliability assessments further indicate that the existing 230kV line is vulnerable to thermal overloads during heavy east-to-west power transfers across the Cascade Range.

These findings represent a significant development in the planning process and demonstrate that WSPP provides benefits beyond generation access and economic transmission expansion. As a result, the project has been moved into the Corrective Action Plan section of PGE's Local Transmission Plan and is now recognized as a reliability-driven project required to address North American Electric Reliability Corporation (NERC) Transmission Planning Standard TPL-001-5 requirements.

Additionally, PGE's service territory is projected to experience load growth over the coming decades, with demand expected to increase from approximately 2.5 GWa in 2026 to 4.9 GWa by 2044 This growth is driven by a combination of large industrial load requests, semiconductor manufacturing expansion, datacenter development, and widespread electrification of transportation and buildings.

Even under moderated growth scenarios, increasing demand and a more variable resource mix, reinforces the need for reliable, deliverable transmission capacity.

K.6.1.2 Regional Significance

WSPP is an important component of the evolving regional transmission portfolio needed to support reliability, resource adequacy, load growth, and access to diverse energy resources across the Pacific Northwest and broader Western Interconnection. The project is reflected in broader regional transmission planning efforts, including the WestTEC 10-Year Transmission Study, which evaluates the transmission infrastructure necessary to address changing regional resource and load conditions.

WSPP is complementary to other significant regional transmission investments, including the North Plains Connector and Boardman-to-Hemingway projects. These projects serve different but complementary functions within the regional system, strengthening key transmission corridors, expanding access to geographically diverse resources, increasing transfer capability between areas of the Western grid, and improving the ability of utilities to respond to changing system conditions. Collectively, these investments can provide greater optionality for meeting future resource needs and reduce reliance on any single transmission path, resource area, or market.

WSPP is particularly important to PGE because it strengthens a critical transmission corridor connecting PGE's system with central and eastern Oregon and the broader regional grid. When considered alongside other regional projects, WSPP contributes to a more interconnected and resilient transmission network capable of supporting Oregon's long-term reliability and clean energy objectives while preserving flexibility as regional markets, resource development, and load forecasts continue to evolve.

K.6.1.3 DOE GRIP Funding and Project Development

In 2023, the CTWS was selected to receive a $242 million Grid Resilience and Innovation Partnerships grant from the U.S. Department of Energy to rebuild the approximately 100-mile Bethel-Round Butte transmission corridor and upgrading the facility from 230 kV to 500 kV. The

initial grant of $250M included community benefits provisions for clean energy workforce, K-12 education and partnerships to support the priorities of the past administration. CTWS serves as the prime recipient of the DOE GRIP award, while PGE participates as a subrecipient responsible for executing defined project activities in support of the WSPP.

Under the currently funded GRIP scope, the upgraded single-circuit 500kV facility is expected to enable up to approximately 2,000MW of import capability into PGE service territory. The anticipated commercial operation date (COD) for this configuration is 2032.

Future expansion opportunities are also being evaluated. Under a two-circuit 500kV configuration, the corridor could provide approximately 2,800MW or more of import capability, significantly strengthening the region's ability to access diverse generation resources and meet projected load growth. The estimated COD for a second circuit is 2035.

K.6.1.4 Integration with BPA Transmission Expansion Plans

Within PGE's local transmission system, current constraints on the North of Pearl transmission path currently limit south-to-north power delivery into the Sherwood, Beaverton, and Hillsboro load areas. Planned PGE and BPA 230kV system upgrades are expected to address near-term congestion on this path by approximately 2030.

Beyond these near-term improvements, BPA's Grid Expansion Reliability Program (GERP) identifies major 500kV upgrades on both the North of Pearl and the North of Marion transmission paths. Studies indicate that constraints are likely to emerge on the North of Marion path in the post-2030 timeframe. Completion of these BPA upgrades will materially increase regional transfer capability and enhance the long-term benefits of WSPP.

The ultimate transfer capability of WSPP will be directly influenced by the status of BPA's regional transmission upgrades at the time the project enters service. Current planning estimates indicate that the initial single-circuit upgrade could provide approximately 1,000 MW of transfer capability upon entering service in 2032. As BPA completes its associated GERP transmission improvements, an additional 1,000MW of transfer capability could be realized on the single circuit in by 2035. A future second 500kV circuit could provide an additional 800MW or more of incremental transfer capability, resulting in a total transfer capability exceeding 2,800MW in 2035.

K.6.1.5 Current Status

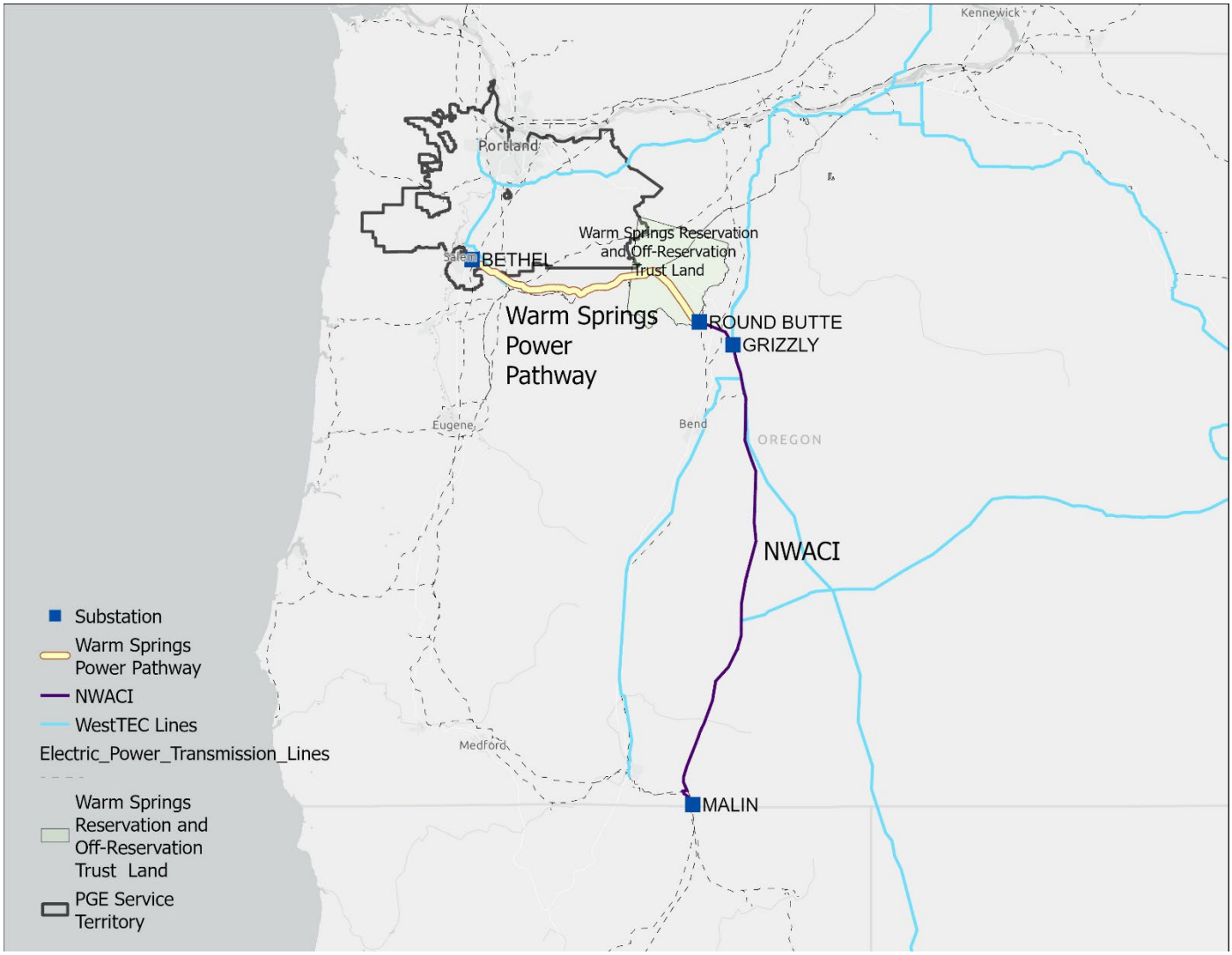
The project continues to advance through development and implementation activities, including permitting, environmental review, engineering design, procurement planning, construction preparation, stakeholder coordination, tribal engagement, and community outreach. CTWS and PGE remain committed to successful delivery of the Warm Springs Power Pathway as a critical transmission investment supporting regional reliability, economic growth, resilience, and long-term energy needs throughout Oregon and the Pacific Northwest.

K.6.1.6 CEP/IRP Portfolio Modeling

Portfolio analysis models the WSPP line using two (2) circuits. The timing and capacity are designed to approximate the complexities of WSPP's path rating dependency on BPA North of Pearl and North of Marion upgrades which, when complete, allow for a total transfer capability exceeding

2800 MW. WSPP Circuit One earliest COD is assumed to be 2032 with an assumed transfer capability of just 1000 MW, to reflect the project's capacity prior to BPA upgrades. WSPP Circuit Two is dependent on Circuit One prior model selection. WSPP Circuit Two's earliest COD is assumed to be 2035 reflecting additional construction time and the associated path rating dependency of BPA's Willamette Valley upgrades. WSPP Circuit Two has an assumed capacity of 2000 MW reflecting the incremental capacity beyond Circuit One due to both Circuit Two energization and completion of BPA upgrades which uprates Circuit One capacity. PGE's IRP planning approach is conservative in so far as Circuit One is forecasted to allow for 2000 MW of transfer capability following BPA upgrades without further expenditure on Circuit 2. However, IRP's portfolio analysis requires both Circuit 1 and Circuit 2 to be completed to access a combined 3000 MW. The capital cost of WSPP Circuit One and Circuit Two are assumed to be consistent those figures reported in the WestTEC 10-year report.

Figure 225. Warm Springs Power Pathway Upgrade

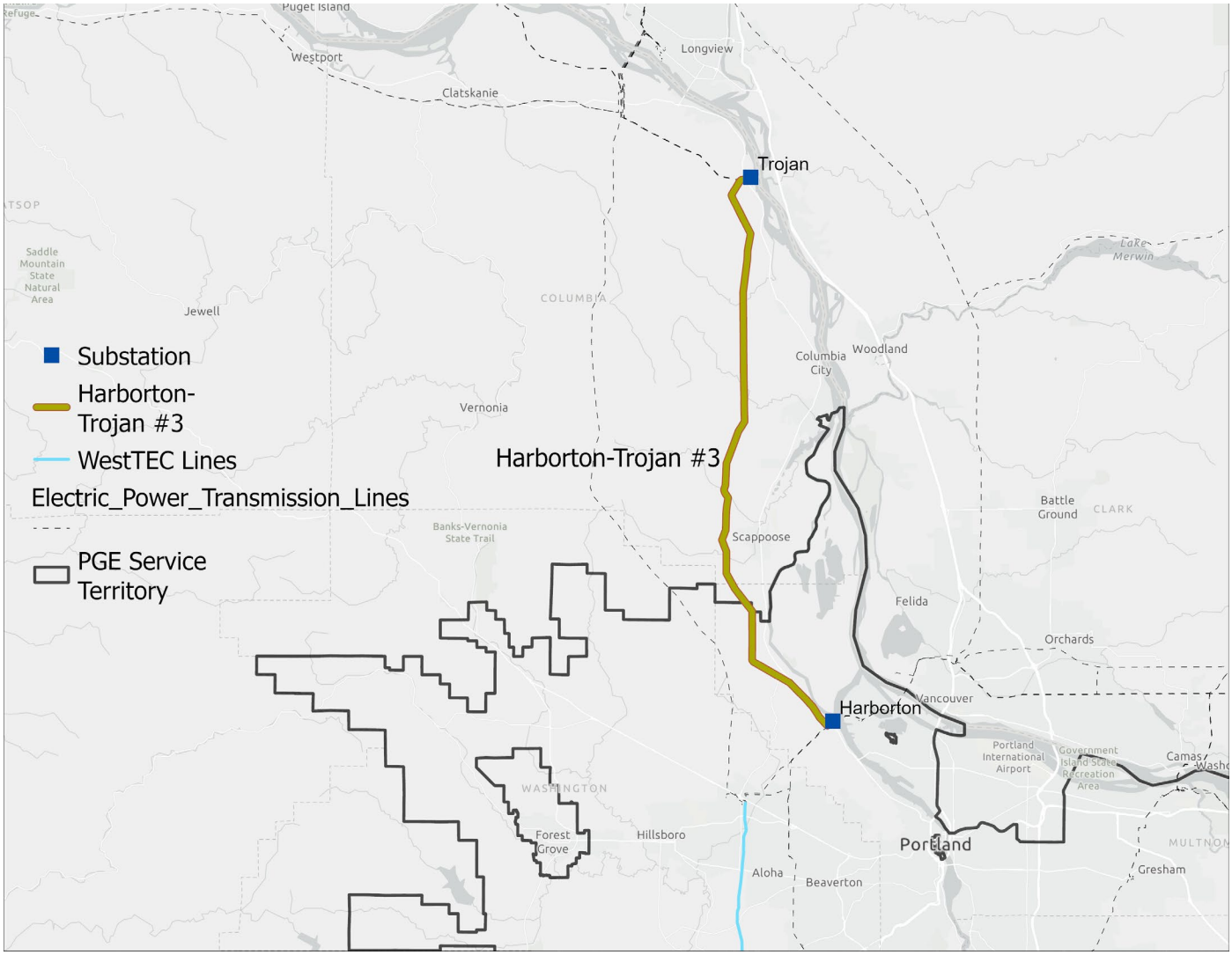


K.6.2 Harborton-Trojan #3 Upgrade

Harborton-Trojan #3 Upgrade is a 34-mile 230 kV transmission option between these two (2) PGE substations at the north-west edge of PGE's service territory. The project would run parallel to two (2) existing PGE transmission lines, in service since the 1970s. PGE currently owns the majority of the right-of-way (ROW) necessary to complete this upgrade. The project is estimated to enable up to 700 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. This project will increase capacity to import energy through the BPA transmission system into PGE's service territory, expanding access to renewable resources and regional energy markets. To access the newly enabled capacity, PGE would need to work closely with BPA to allow power scheduling to Trojan from remote resources. Currently South of Allston capacity can only be utilized from the Beaver/Port Westward Complex.[317] The additional transfer capability would help support growing customer demand, increase resource diversity, improve system flexibility, and strengthen PGE's ability to reliably deliver clean energy resources from across the Pacific Northwest into the Portland load area. While not included in the IRP methodology, the electrical configuration of the project is expected to potentially provide North or Pearl flowgate relief. The capital costs of the Harborton-Trojan upgrade are assumed consistent with those reported in the WestTEC 10-year report.

[317] PGE's November Roundtable - Transmission - Step 3 - Market Access.

Figure 226. Harborton-Trojan #3

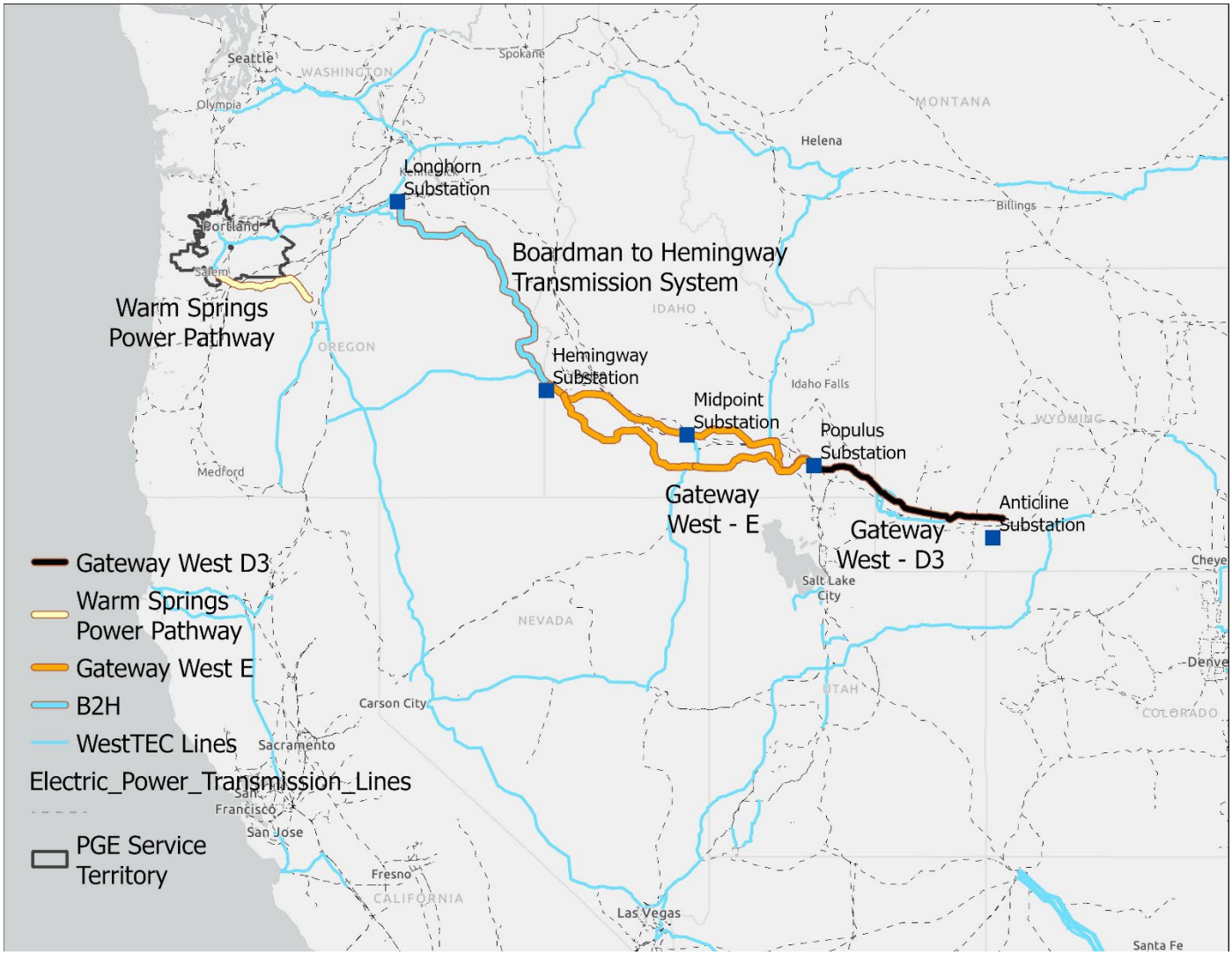


K.6.3 Gateway + B2H + Longhorn (Gateway)

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 Round Butte is identified as a viable wheel to bring energy to PGE service territory following completion of WSPP. 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. 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. From a commercial perspective, without securing transmission service rights across Gateway, PGE's long-term access for Wyoming wind resources

will be limited. The assumed capital costs of Gateway are consistent figures reported in the WestTEC 10-year report as supplemented by public figures published by PacifiCorp.

Figure 227. Gateway Transmission Option



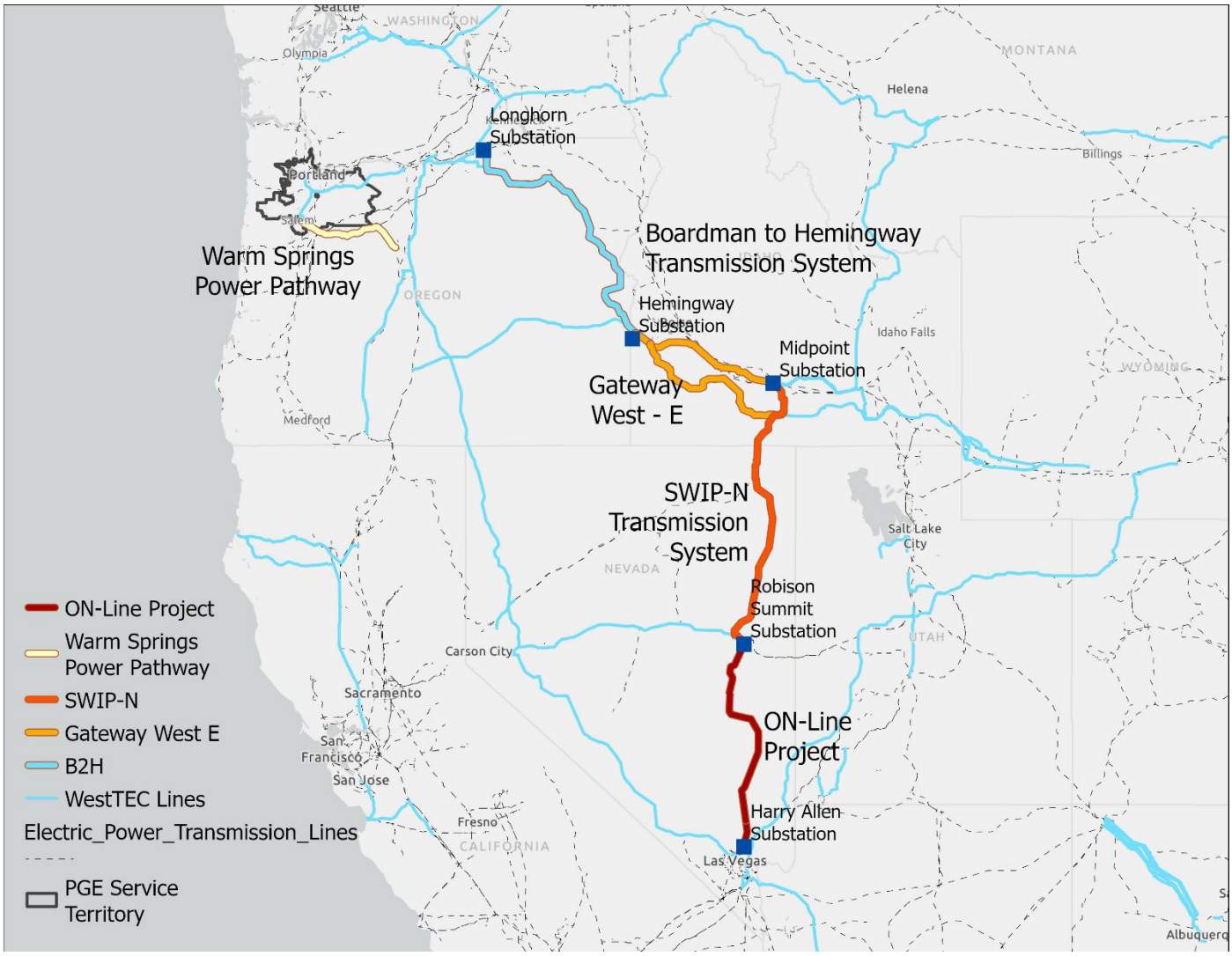
K.6.4 NVE + SWIP-N + Gateway + B2H + Longhorn (SWIP-N)

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 (2) 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 Round Butte wheel to bring energy to PGE service territory following completion of WSPP. SWIP-N is estimated to provide capacity up to 400 MW of Nevada Solar by 2035 and an

additional 400 MW of market access in winter.[318] The 2035 COD reflects the expected timeline for new BPA TSRs on Longhorn to Round Butte. The assumed capital costs of SWIP-N are consistent with those figures published in the WestTEC 10-year report.[319]

Figure 228. SWIP-N Transmission Option



K.6.5 North Plains Connector

North Plains Connector is a 420-mile high-voltage direct current (HVDC) line that extends from Montana's Colstrip 500 kV substation to two (2) North Dakota interconnection points (Center and St. Anthony), linking MISO/SPP power markets with PGE's existing transmission network. NPC's western terminus connects to the Colstrip Transmission System, currently being assessed for capacity upgrades.

[318] PGE's November Roundtable - Transmission - Step 3 - Market Access
[319] PGE's November Roundtable - Transmission - Step 3 - Market Access.

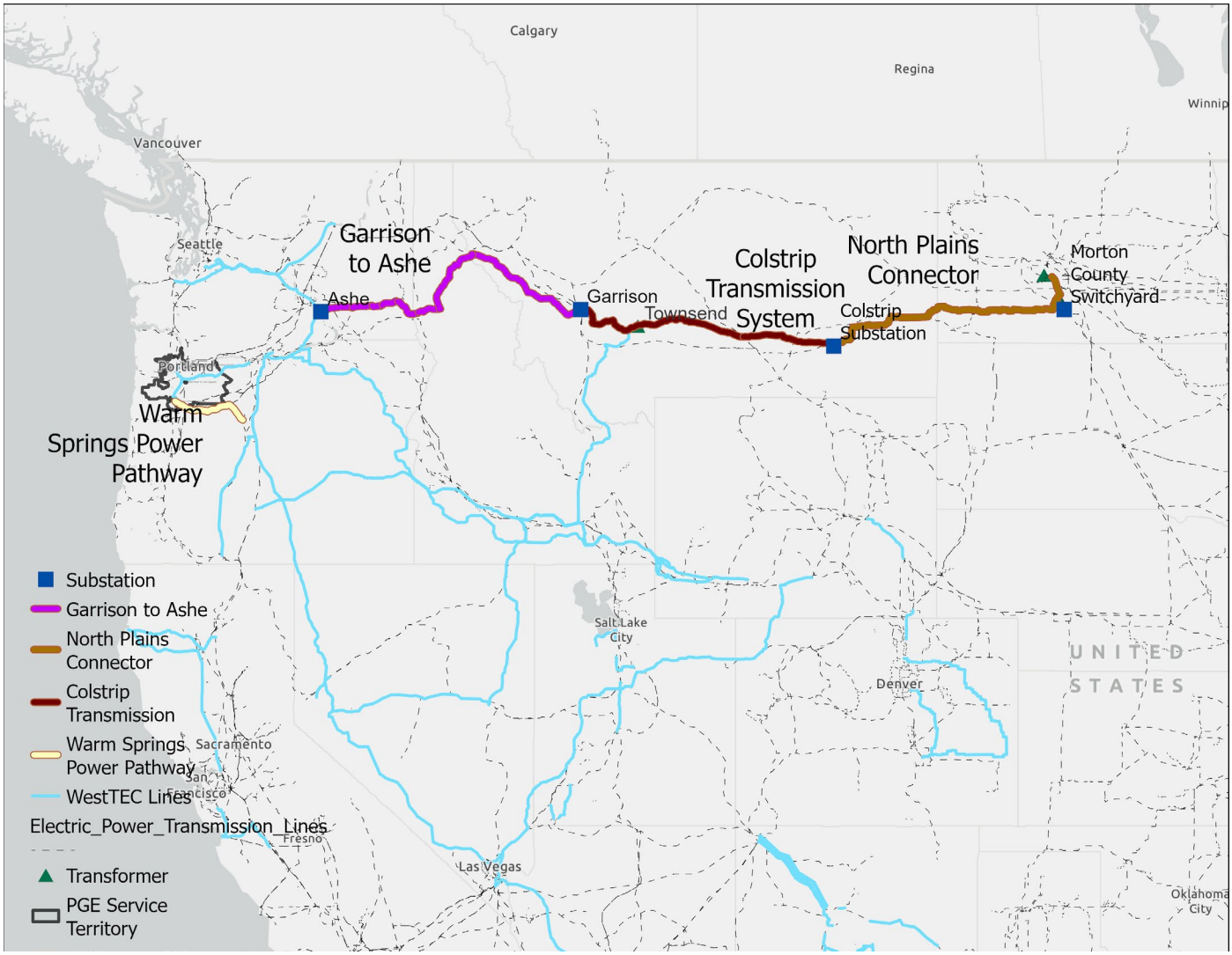
The NPC option provides 600 MW of transmission capacity from SPP/MISO to Colstrip no earlier than 2032.Using 270 MW of existing transmission rights from Colstrip to PGE, NPC transmission capacity can be used to deliver 360 MW of interconnected projects in the North Dakota resource zone as early as 2032. In addition, approximately 140 MW of front office transactions from the diverse SPP/MISO market can be secured following NPC selection supported by existing transmission rights from the Colstrip and Clearwater generation facilities.

Beginning in 2035, additional transmission facilities can be selected by the model to further increase deliveries to PGE from the North Dakota region. As recommended in the WestTEC 10-year plan, a 500 kV series capacity upgrade on the Colstrip system and transmission expansion along the Garrison to Ashe corridor are required by 2035 to support regional transmission reliability and congestion. Beginning in 2035, should IRP's model select Garison to Ashe upgrade the remaining transmission capacity to North Dakota region is accessible allowing for another 440 MW of resource interconnection capacity and approximately 170 MW of front office transactions. From Ashe. A BPA wheel to Round Butte is assume to deliver on the contingent transmission expansion of WSPP.

GridUnited is developing the project in partnership with Pattern Energy. Potential participants include Midwest power organizations ALLETE, MDU Resources and Minnkota Power Cooperative, and Pacific Northwest utilities Avista, Puget Sound Energy, PacifiCorp, and NorthWestern Energy. PGE is pursuing a 20% share of the project. PGE signed an MOU in 2024 and is currently evaluating potential options for ownership and participation. NPC received a Grid Resilience and Innovation Partnerships (GRIP) grant from the US government, for approximately $700 million, which will be used to defray the overall costs of the transmission project. The project is expected to come online by end-2032.

The line's primary benefit is access both to North Dakota high capacity-factor wind, and 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% of PGE's highest demand hours. The availability of North Dakota resource benefits has been confirmed by multiple studies commissioned or reviewed by PGE.

Figure 229. North Plains Connector



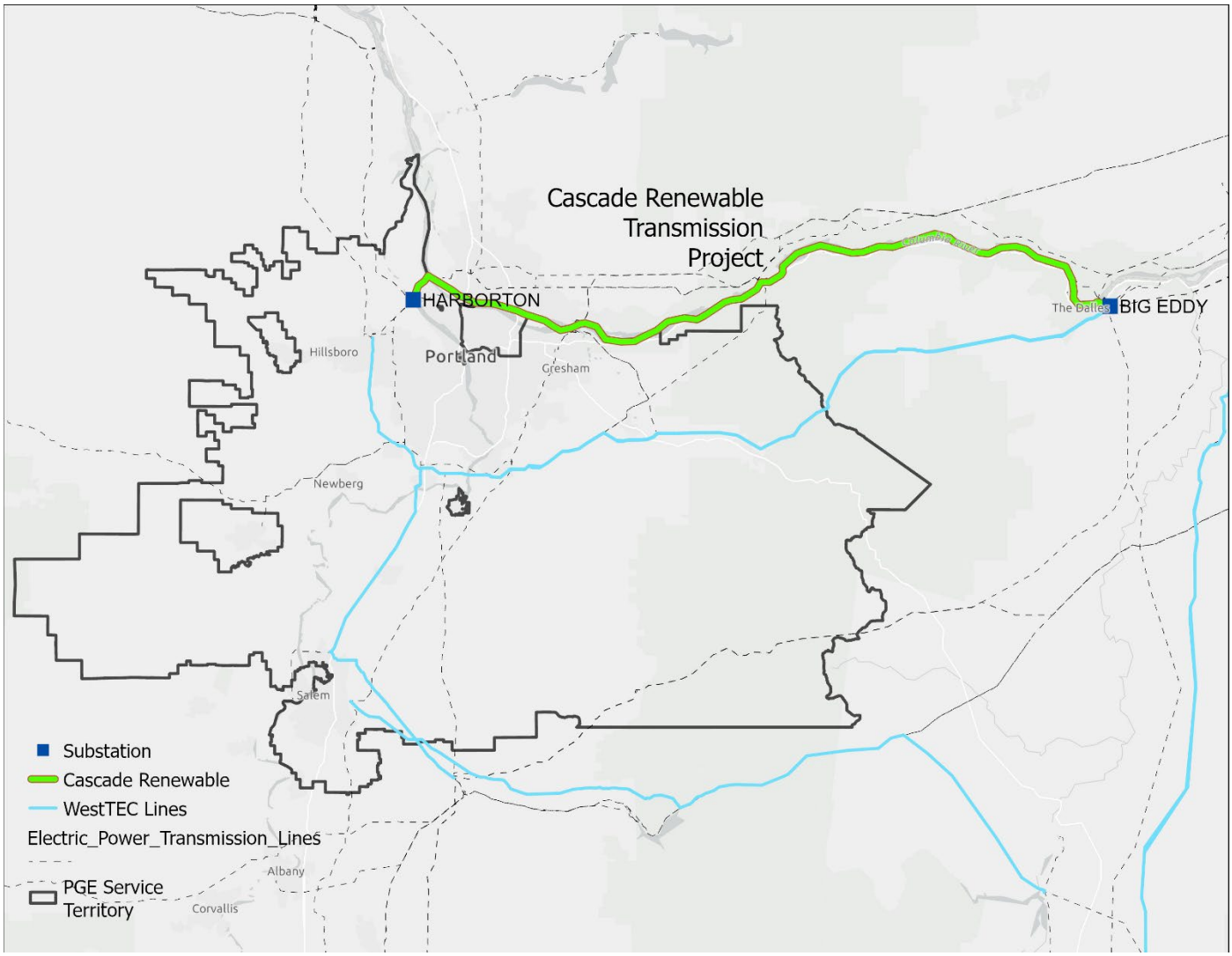
K.6.6 Cascade Renewable Transmission Project

The Cascade Renewable Transmission Project (CRTP) 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 to be available by 2038.

CRTP is not assumed to provide access to diverse markets.[320] While not included in the IRP methodology, the electrical configuration of the project is expected to potentially provide North or Pearl flowgate relief.

PGE is not currently participating in CRTP. The capital costs of CRTP are based on publicly reported cost estimates.

Figure 230. Cascade Renewable Transmission Project



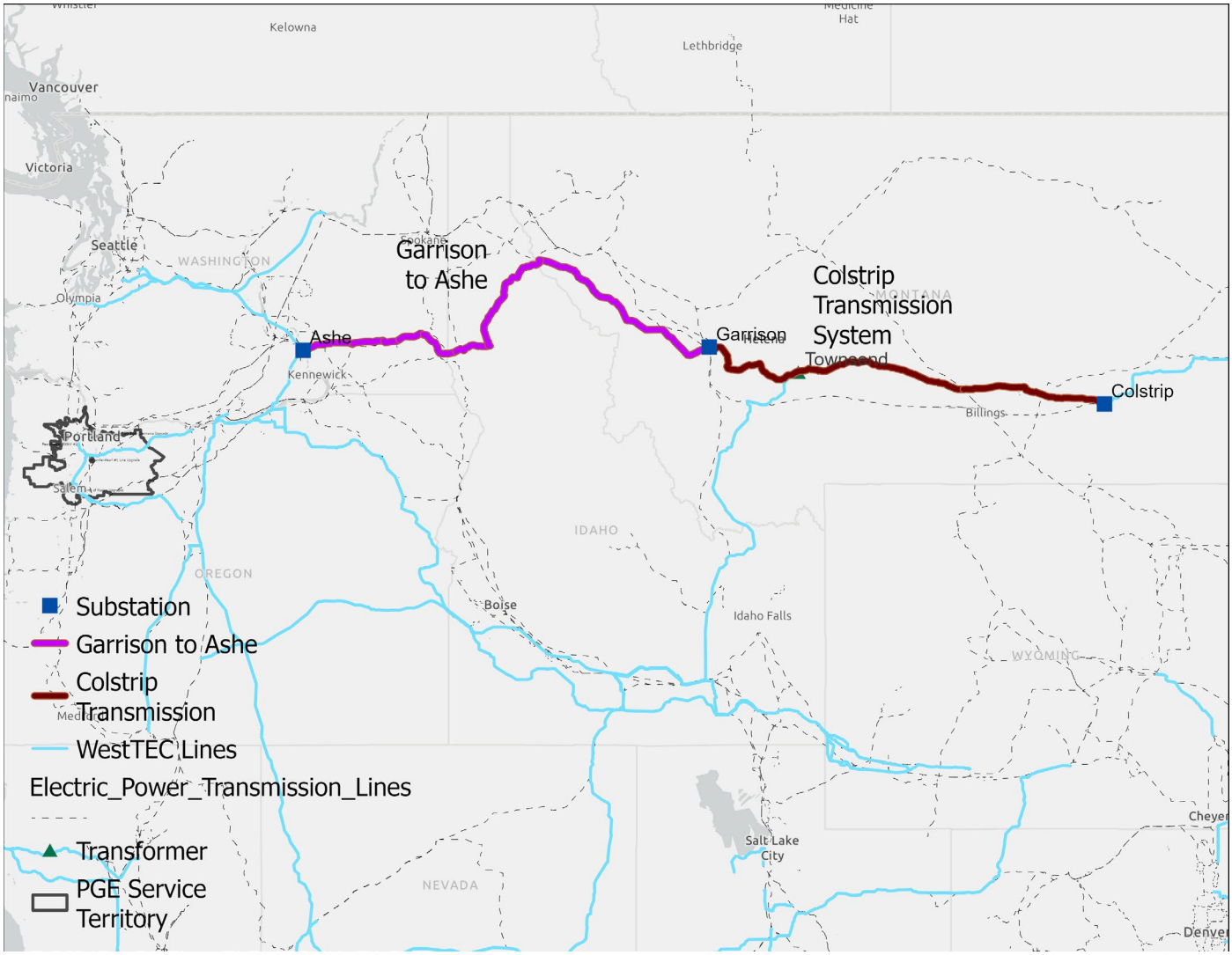
K.6.7 Garrison to Ashe

This transmission option would establish a new 500 kV pathway from Montana to BPA's Ashe Substation in eastern Washington, increasing transfer capability between Montana and the Pacific Northwest. WestTEC's 10-Year Horizon Study identified a new Townsend–Ashe 500 kV line as an interregional transmission solution, modeled at approximately 500 miles, 3,845 MW. WestTEC

[320] PGE's November Roundtable - Transmission - Step 3 - Market Access.

found that the project would increase import capability into the Pacific Northwest while alleviating constraints on Path 8 (Montana–Northwest) and other elements of BPA's eastern transmission system. Consistent with WestTEC's study scope, the Garisson to Ashe project is identified as being necessary by 2035 to address interregional reliability, deliverability and efficiency challenges. As studied in PGE's 2026 IRP, this project is combined with the planned 500kV series capacitor upgrade of the Colstrip Transmission System. Assumed capital costs are consistent with figures reported in the WestTEC 10-year study.

Figure 231. Garrison to Ashe

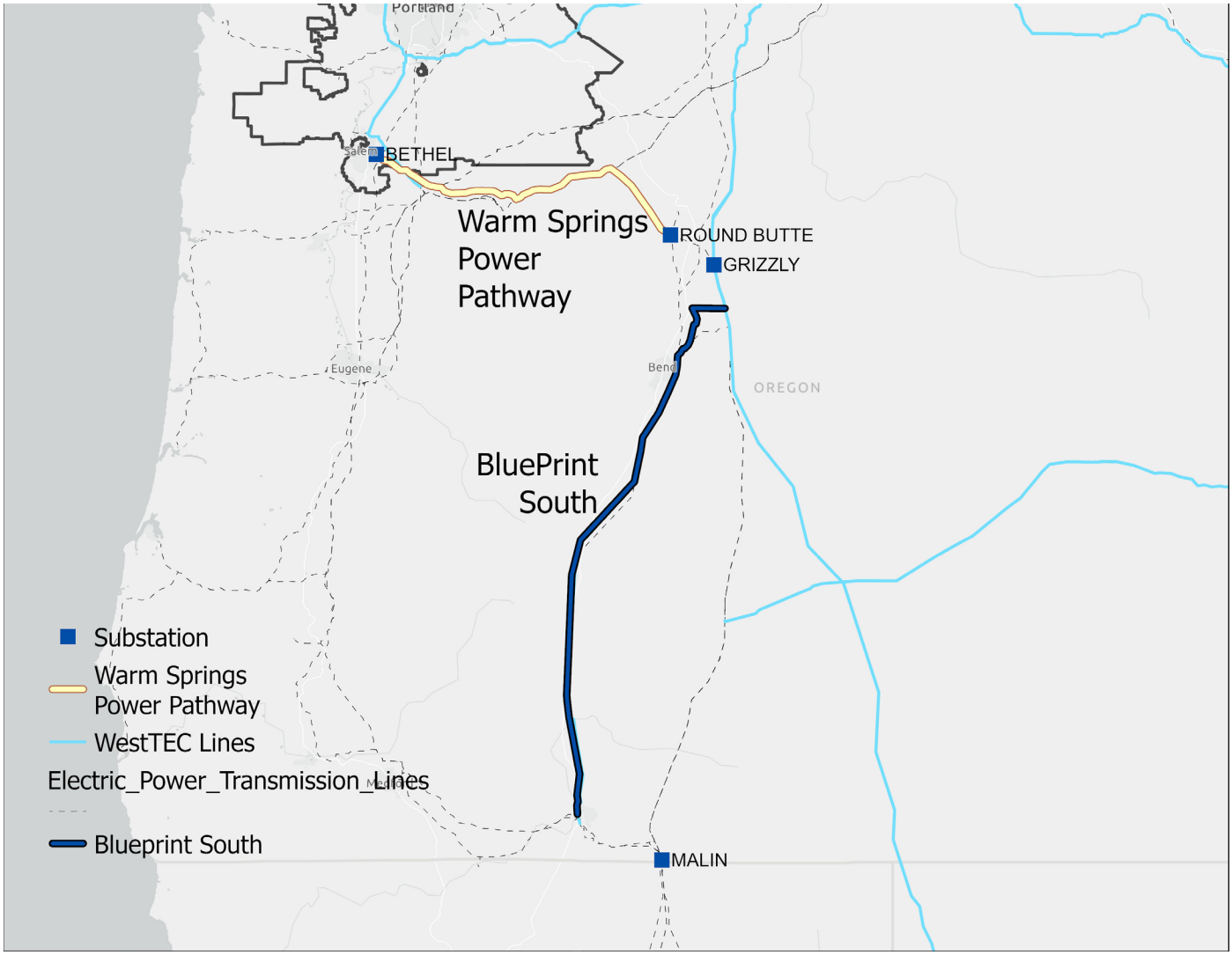


K.6.8 Blueprint South

PacifiCorp's Blueprint South project would add a new 500 kV transmission pathway through south-central Oregon, connecting the Snow Goose Substation near Klamath Falls to a new Corral-area substation near Central Oregon. The project includes approximately 160–180 miles of new 500 kV transmission, as well as associated 230 kV facilities, substations, and series compensation. PacifiCorp identifies the project as part of a broader "Blueprint" expansion intended to strengthen

the north-south transmission backbone in Oregon, increase capacity to serve growing loads, reduce transmission constraints, and facilitate integration of additional generation resources. WestTEC included Blueprint South in its 10-Year Horizon portfolio as the Corral–Snow Goose 500 kV line, modeling approximately 161 miles of new transmission at an estimated cost of $763 million. Assumed capital costs are consistent with figures reported in the WestTEC 10-year study.

Figure 232. Blueprint South

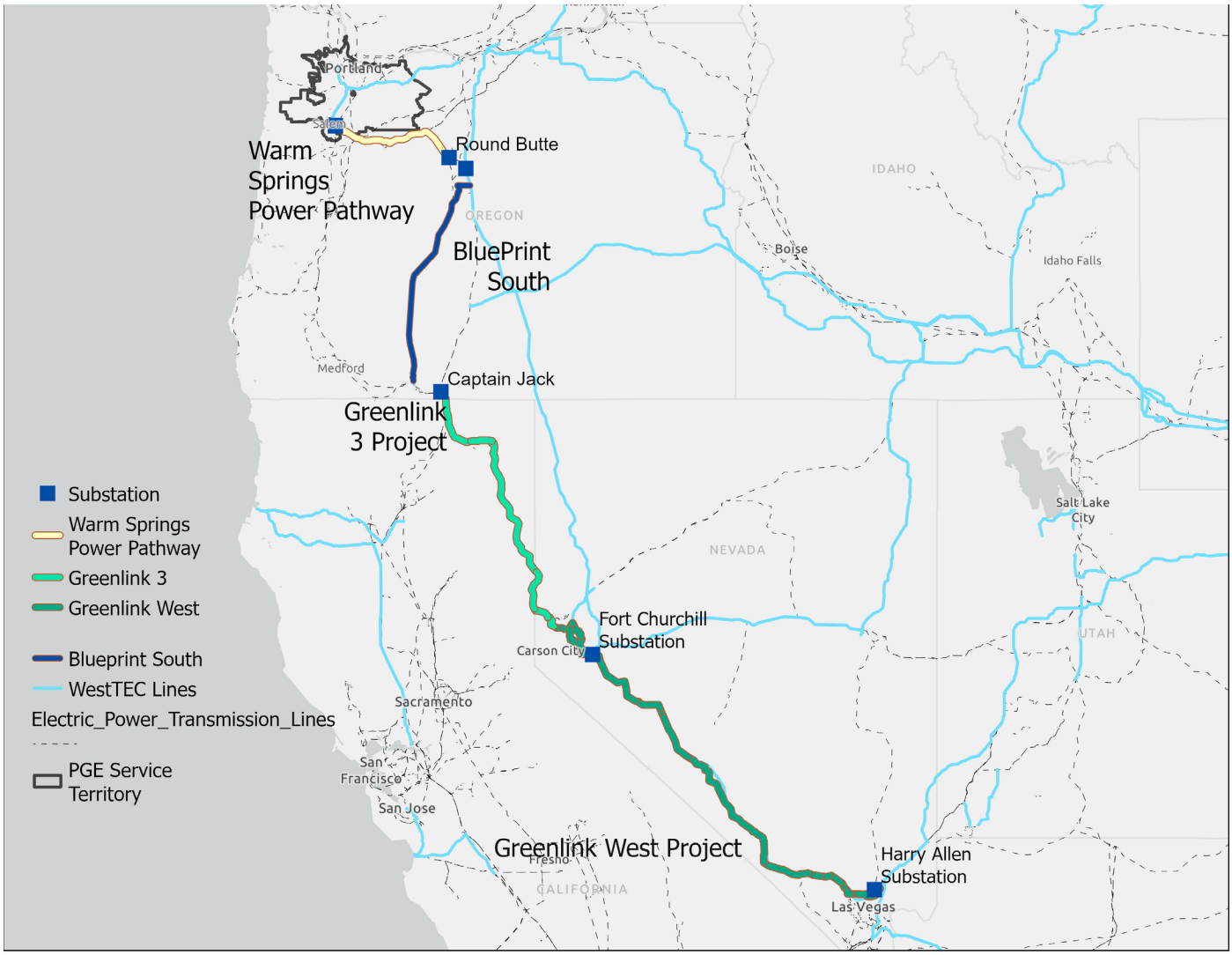


K.6.9 NVE + Greenlink 3 + Cpt. Jack to Grizzly + BRB upgrade (Greenlink)

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 (4) 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, following the contingent Blueprint South upgrade. Finally, the upgrade is contingent on WSPP place to bring the energy to PGE's service territory. The Greenlink has 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 490 MW of market access in the winter is assumed.[321] The assumed capital cost of Greenlink are consistent with those reported in the WestTEC 10-year report.

Figure 233. Greenlink Transmission Option



K.6.10 Transmission Options Summary

Table 111 provides a summary of the 11 transmission options discussed above and their assumptions used for portfolio analysis.

[321] PGE's November Roundtable - Transmission - Step 3 - Market Access.

Table 112. Transmission Options

Project	Developer	Capacity (MW)	MW Available to PGE	COD	Extra-regional Market
Warm Springs Power Pathway Circuit 1	CTWS/PGE	1,000	1,000	2032	CAISO
Warm Springs Power Pathway Circuit 2 (Including BPA Upgrades)322	CTWS/PGE	2,000	2,000	2035	N/A
Cascade Renewable	CRT LLC[323]	1,100	1,100	2032	None
Harborton-Trojan #3	PGE	545	545	2035	None
Blueprint South	PacifiCorp	725	600	2035	CAISO
Gateway	PacifiCorp/IDP	5,000	400	2035	None
SWIPN	LS Power	4,073	400	2035	CAISO/DSW
Boardman to Hemmingway	IDP/PacifiCorp	1,000	400	N/A	None
Garrison to Ashe	BPA	1,500	330	2035	MISO/SPP
North Plains Connector	Grid United	3,000	270	2032	MISO/SPP
Greenlink	NV Energy	800	490	2035	CAISO/DSW

[322] As further described in Appendix K Long Term Transmission Options, transmission planning results indicate that the capacity of WSPP Circuit One grows from approximately 1000 MW to 1800 MW following planned BPA upgrades in 2035. Circuit Two adds an additional 800 MW or more of capacity contingent on planned BPA upgrades.
[323] Cascade Renewable Transmission, LLC includes three principal companies: PowerBridge, LLC, Sun2o Partners, LLC and NextEra Energy Transmission, LLC

Appendix L Short Term Transmission Options

This appendix describes how PGE's 2026 Integrated Resource Plan evaluates transmission as part of the resource planning framework. In addition to long-term transmission products, transmission upgrades, and system expansions, this IRP also considers the potential role of short-term transmission service in supporting resource deliverability, market access, and portfolio flexibility over the planning horizon.

Transmission planning is a key input to reliable and affordable resource planning because the value of generation, storage, market purchases, and regional resource diversity depends not only on resource availability, but also on the ability to move energy to where it is needed. Long-term transmission service and new transmission infrastructure remain important tools for meeting sustained delivery needs and enabling future resource development. However, short-term transmission products may also provide value by allowing PGE to access available transfer capability, respond to changing system conditions, support seasonal or market opportunities, and bridge periods before new long-term service or infrastructure is available.

The methodology described in this appendix is intended to assess when and how short-term transmission may reasonably contribute to meeting system needs within the IRP. The analysis considers the availability, cost, timing, and reliability characteristics of short-term transmission products, recognizing that these products differ from long-term firm service and may not provide the same level of certainty. Rather than treating short-term transmission as a substitute for durable transmission solutions, the IRP evaluates it as one planning tool that can complement long-term transmission procurement and expansion strategies.

L.1 PGE Transmission Interfaces

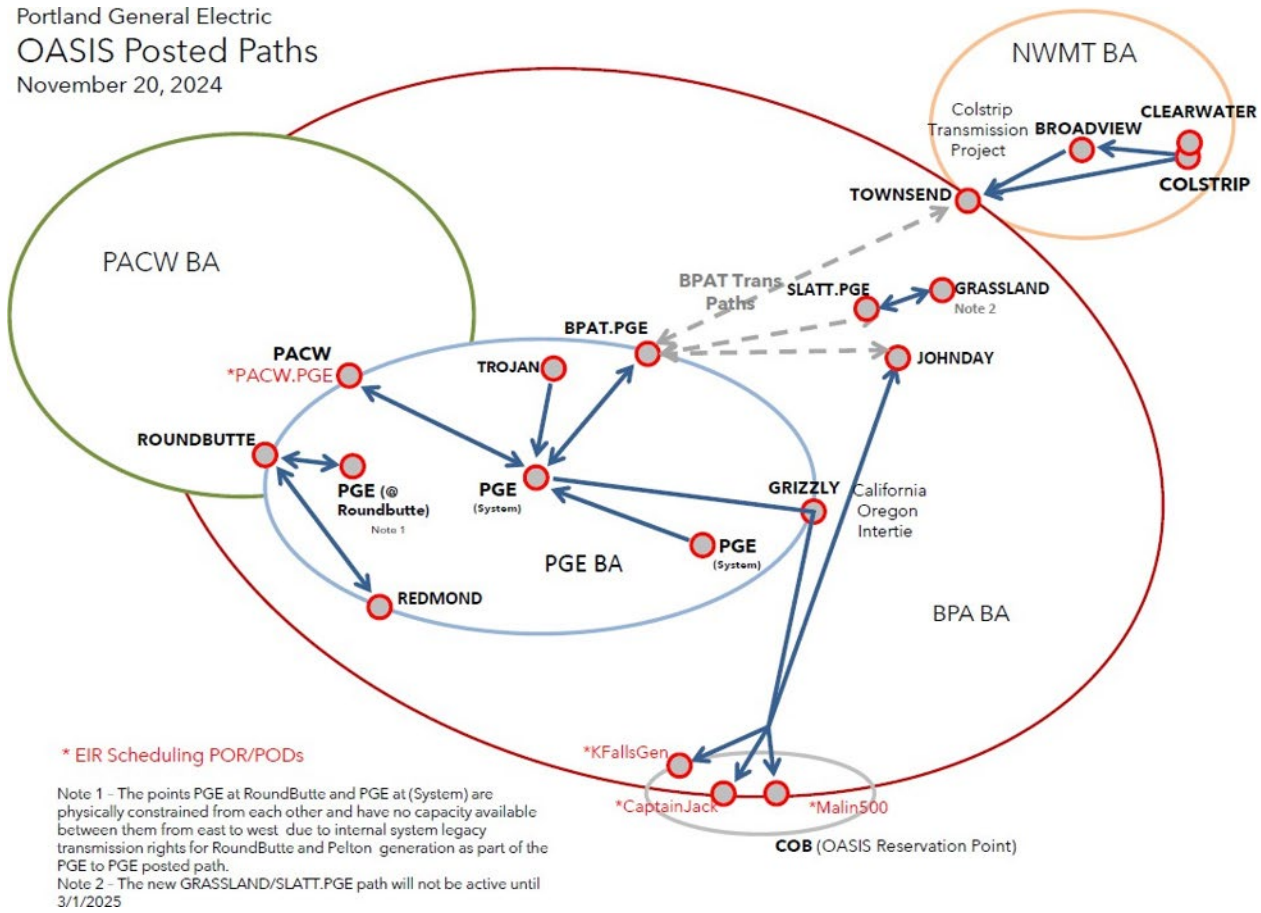
PGE's transmission system (Figure 234) is highly interconnected with and exists almost entirely within the footprint of BPA. BPA is a federal power marketing administration (PMA) that operates approximately 75% of the transmission in the Pacific Northwest, consisting of more than 15,000 miles of high-voltage transmission lines. BPA operates transmission in Idaho, Oregon, Washington, western Montana and small parts of eastern Montana, California, Nevada, Utah and Wyoming.[324]

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. 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 run 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

[324] BPA transmission system: https://www.bpa.gov/-/media/Aep/about/publications/maps/bpa-transmissionlines-and-facilities.pdf.

connects Oregon to California. PGE jointly owns NWACI with BPA and PacifiCorp, and it is operated by BPA.

Figure 234. Oasis Posted Paths[325]



L.2 Paths and Flowgates

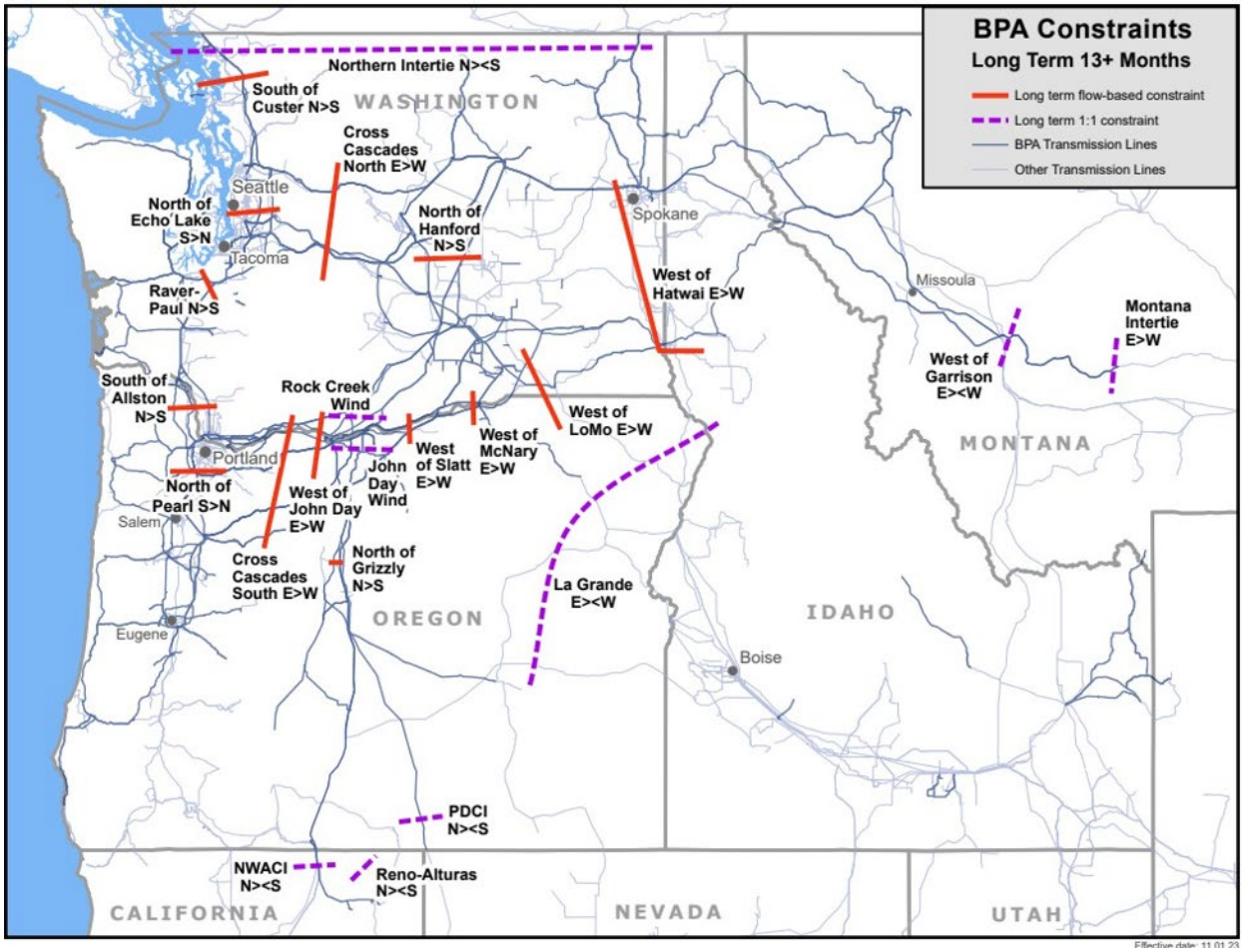
To get to PGE's system, power generated or purchased from remote locations must travel through different paths and flowgates on the region's transmission system. A flowgate is a collection of transmission lines and facilities that collectively start in a geographically similar area and terminate in a different geographically similar area. These flowgates are typically operated by BPA and are shown in Figure 235. 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:

[325] https://www.oasis.oati.com/woa/docs/PGE/PGEdocs/OASIS_Posted_Paths_v19_11-20-2024.pdf

- 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 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 235. BPA Constraints[326]



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, including solar exports from California and the desert southwest and/or wind from 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.

[326] Source: https://www.bpa.gov/-/media/Aep/transmission/atc-methodology/atc-long-term-constraints-11-1-23.pdf

- Transmission to PGE also typically impacts 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, owned by BPA, PGE and PAC, that route from north to south just north of the 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 Hatwai flowgate before reaching several other flowgates on the way to PGE's load in the Willamette Valley.

L.3 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 & #3 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 Pacific Northwest. 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 MW 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 datacenter industrial sectors, much of the forecasted growth will locate in the Beaverton/Hillsboro area on the west

side of PGE's service territory. Absent corrective action, existing constraints north of the NOPE flowgate could limit transmission service and the associated economic activity. 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.

L.3.1 Headroom (MW) Analysis for WECC Interfaces and BPA Flowgates

This appendix assesses the potential availability of short-term transmission by evaluating forecasted headroom on key WECC interfaces and BPA flowgates relevant to PGE's resource planning and market access. Using GridView production-cost modeling, PGE simulated expected regional dispatch, load, resource additions, and transmission flows under 2035 planning conditions. For purposes of this analysis, headroom represents the modeled difference between the transfer or operating limit of an interface or flowgate and the forecasted flow across that path. This provides an indication of where transmission capability may remain available under future system conditions and where congestion or limited transfer capability may constrain the use of short-term transmission products.

This is a reasonable approach for IRP planning because the question is inherently forward-looking: whether short-term transmission could support PGE's future portfolio needs depends on how the regional grid is expected to operate in the planning year, not only on how it has operated historically. GridView allows PGE to evaluate short-term transmission opportunities within a consistent regional production-cost framework that reflects forecasted loads, resource portfolios, market dispatch, and transmission constraints across the Western Interconnection. While modeled headroom does not guarantee that short-term transmission service will be available in real time or under all operating conditions, it provides a transparent and analytically grounded screening method for identifying paths where short-term transmission may be more plausible, where reliance would carry greater risk, and how these opportunities could complement long-term transmission service, upgrades, and expansion planning.

PGE analysis provides a baseline assessment of how existing transmission infrastructure may perform under projected 2035 system conditions, evaluated under two (2) scenarios with and without planned network upgrades between 2027-2035. The geography of PGE's network upgrade analysis included the Northwest, Idaho, Montana, and Nevada region.

The impact on utilization of the identified WECC paths and BPA flowgates was evaluated by calculating the "Headroom (MW)" – defined as the difference between the actual flow on a path and its corresponding Total Transfer Capability (TTC). A lower headroom value indicates a higher degree of congestion and reduced available transfer capacity on the interface, while a higher headroom value indicates greater available capacity and lower constraint risk.

The following WECC interfaces and BPA flowgates were included in this analysis:

Table 113. Included WECC Interfaces and BPA Flowgates

West of Cascades North (Path 4)	West of John Day (Path 86)	North of Grizzly
▪ West of Cascades South (Path 5)	▪ West of McNary (Path 87)	▪ North of Hanford
▪ West of Hatwai (Path 6)	▪ West of Slatt (Path 88)	▪ Raver-Paul

West of Cascades North (Path 4)	West of John Day (Path 86)	North of Grizzly
▪ South of Allston (Path 71)	▪ North of Pearl (NOPE)	▪ West of Lower Monumental

The analysis was conducted in the Hitachi GridView Production Cost Model (PCM), with the 2035 case derived from the WestTEC V2.0 2035 Case.

The WestTEC V2.0 case includes the portfolio of planned transmission projects within the 10-year horizon that meet the WestTech Study Plan criteria and are incorporated in the 2035 Reference Case; however, it does not include the WestTEC-identified transmission solutions developed through the 10-Year Horizon Study to address reliability, deliverability, and economic needs. Therefore, some of the transmission constraints observed in this analysis may be mitigated by the implementation of these WestTech-identified upgrades summarized in 2026 WestTech 10-Year Horizon Report.[327]

L.3.2 Key Assumptions

- Analysis horizon: Year 2035
- Load, Generation & Economic Assumptions: Year 2035 from WestTEC V2.0 2035 case
- Updated season NOPE TTCs for 2035 provided by BPA
- Transmission Network:
- Case 1 - 2027 Topology: No transmission infrastructure additions and changes assumed for NW, ID, MT, and NV regions between 2027–2035
- Case 2 - 2035 Topology: Planned transmission infrastructure additions and changes assumed for NW, ID, MT, and NV regions between 2027–2035

L.3.3 Results

L.3.3.1 Headroom Graphical Analysis

The following graphs illustrate the estimated average headroom values for each evaluated path and flowgate for the two (2) scenarios considered, providing insights into:

- Potential constraint risks
- Use trends across the study period
- Identification of constrained interfaces that may inform future transmission investment considerations

NOTE: The graphs use a gradient color-coding scheme to visually represent constraint risk levels:

[327] https://www.westernpowerpool.org/resources/westtec-10-year-horizon-report

Table 114. Color Coding Legend

Color	Interpretation
Red	Most constrained hours – lowest available headroom
Yellow	Moderately constrained hours – medium available headroom
Green	Least constrained hours – highest headroom available to the path
Blank Green	Flow in unbounded direction – no TTC limit applicable

* Intermediate gradient colors represent varying degrees of constraint risk between these extremes, enabling intuitive visual identification of constraint patterns across the study period.
* TTC Directionality: TTC is defined separately for each direction of path flow. The following paths have a defined TTC in one direction only, with flow being unbounded in the opposite direction: North of Pearl, Path 6, Path 71, Path 86, Path 87, and Path 88. Hours where average flow occurs in the unbounded direction are displayed as blank in the graphical analysis and color-coded dark green, indicating no binding constraint on headroom.

L.3.3.2 Guide to Interpreting Headroom Patterns

The headroom results across the evaluated WECC paths and BPA flowgates reveal varying levels of constraint risk projected for the 2035 system conditions, both with and without network changes in NW, ID, MT, NV between 2027 and 2035.

The graphical analysis enables visualization of peak constraint hours throughout the year, providing an intuitive representation of transmission utilization patterns across evaluated interfaces:

- Hours with persistently low headroom values indicate a heightened risk of curtailment for non-firm transmission, warranting closer attention in the IRP planning process.
- Hours with higher headroom suggest relatively adequate transfer capacity under the evaluated scenarios.
- A comparison between the two (2) scenarios provides a direct measure of the transmission relief offered by planned network upgrades, highlighting the value of timely infrastructure investment.
- In some interfaces, planned network upgrades resulted in lower headroom values for part of the year, indicating increased utilization of the interface for delivery of long-distance energy resources to meet load requirements. However, this also implies a higher risk to non-firm transmission on those interfaces.

L.3.3.3 Headroom Heatmaps

Headroom heatmaps all WECC path and BPA flowgates were calculated. Results for North of Pearl, South of Alston, West of Cascades South and West of Hatwai are presented below:

Figure 236. 2027 Average Headroom (MW) by Month and Hour P05 West of Cascades - South

Average Headroom (MW) by Month and Hour
P05 West of Cascades-South

2027 Topology

PT Hour Ending	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	2894	2303	2799	2525	3109	3216	3163	3274	3668	4004	3207	2795
1	2991	2315	2784	2520	3208	3285	3314	3341	3719	4098	3327	2943
2	2972	2281	2678	2477	3319	3255	3439	3426	3772	4099	3327	3012
3	2940	2316	2612	2408	3345	3274	3503	3442	3764	4070	3324	3024
4	2902	2296	2483	2368	3256	3248	3474	3427	3662	3951	3275	2969
5	2804	2282	2322	2235	2853	2616	3040	3165	3385	3629	3194	2894
6	2527	2115	2000	1641	1722	1665	2372	2536	2625	3005	2831	2700
7	2086	1549	1377	1369	1588	1430	2029	2185	2265	2439	2015	2164
8	1613	991	1112	1338	1402	1265	1795	1910	2107	2183	1616	1743
9	1448	880	1158	1415	1377	1227	1683	1814	2081	2164	1430	1493
10	1371	924	1279	1416	1291	1145	1587	1741	2015	2195	1468	1412
11	1381	921	1335	1431	1236	1120	1511	1652	1988	2228	1502	1424
12	1377	944	1387	1519	1263	1171	1476	1576	1936	2244	1596	1458
13	1426	1006	1481	1500	1282	1158	1382	1526	1924	2268	1667	1601
14	1468	1052	1518	1597	1305	1160	1273	1428	1882	2323	1686	1668
15	1523	1086	1513	1591	1349	1142	1160	1355	1864	2398	1721	1745
16	1698	1151	1521	1633	1433	1104	1069	1340	1875	2524	2051	1861
17	1570	1245	1502	1694	1794	1484	1196	1425	2064	2616	1791	1731
18	1340	1052	1437	1997	2513	1964	1454	1626	2197	2523	1594	1510
19	1356	981	1264	1964	2468	2055	1594	1671	2147	2449	1533	1585
20	1515	975	1258	1850	2370	1992	1699	1718	2097	2538	1610	1640
21	1729	1093	1451	1921	2377	2051	1747	1888	2388	2863	1877	1783
22	1989	1367	1790	2164	2444	2230	2097	2287	2713	3208	2152	1983
23	2320	1596	2125	2388	2711	2532	2433	2624	3048	3522	2494	2321

Figure 237. 2035 Average Headroom (MW) by Month and Hour P05 West of Cascades-South

Average Headroom (MW) by Month and Hour
P05 West of Cascades-South

2035 Topology

PT Hour Ending	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	5759	5227	5473	4445	5173	5116	4935	4963	5276	6585	5910	5475
1	5837	5292	5504	4513	5296	5141	5051	4962	5305	6560	5979	5598
2	5824	5301	5458	4501	5357	5227	5172	5001	5322	6567	5967	5622
3	5817	5282	5399	4498	5372	5230	5225	5037	5330	6518	5942	5640
4	5809	5277	5330	4402	5306	5117	5134	4995	5236	6441	5916	5576
5	5742	5213	5165	4277	4852	4547	4609	4696	4973	6209	5849	5591
6	5511	5118	4830	3709	3823	3551	3555	3772	4157	5576	5531	5425
7	5018	4500	4137	3171	3762	3408	3300	3506	3751	5113	4574	4818
8	4418	3743	3794	3007	3461	3116	2960	3205	3528	4773	4208	4361
9	4191	3471	3566	2907	3273	2970	2814	3068	3431	4755	3959	4125
10	4103	3237	3474	2704	3153	2722	2756	2942	3374	4732	3865	3999
11	4048	3003	3415	2522	2764	2674	2643	2826	3286	4737	3872	3950
12	4023	2957	3434	2567	2531	2633	2648	2814	3267	4725	3965	3969
13	4067	3084	3521	2428	2469	2568	2606	2791	3171	4770	4014	4017
14	4134	3187	3594	2566	2605	2706	2636	2735	3144	4793	4030	4138
15	4144	3348	3580	2575	2762	2858	2674	2765	3190	4817	4054	4229
16	4400	3713	3637	2778	3123	2902	2719	2919	3347	4936	4405	4455
17	4364	4216	4012	3286	3805	3535	3093	3209	3691	5026	4330	4348
18	4138	4222	4201	4096	4620	4218	3459	3384	3914	5059	4009	4199
19	4189	4075	4045	4073	4693	4335	3705	3583	3837	5037	4085	4325
20	4274	4019	3952	3959	4710	4225	3750	3473	3811	5136	4236	4371
21	4501	4113	4064	4005	4662	4188	3722	3612	4022	5457	4472	4486
22	4777	4237	4341	3998	4547	4239	3941	3923	4321	5707	4727	4650
23	5096	4418	4642	4150	4625	4492	4209	4279	4598	5978	5034	4936

Figure 238. 2027 Average Headroom (MW) by Month and Hour P06 West of Hatwai

Average Headroom (MW) by Month and Hour
P06 West of Hatwai

2027 Topology

PT Hour Ending	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	2274	2026	1656	1946	2460	2041	2224	2364	2323	2323	2399	2296
1	2302	2079	1704	1956	2543	2114	2219	2391	2366	2313	2425	2335
2	2352	2203	1804	1954	2573	2137	2190	2473	2345	2378	2459	2368
3	2367	2237	1823	1991	2520	2158	2188	2557	2360	2393	2473	2387
4	2340	2222	1840	2025	2584	2127	2211	2579	2392	2438	2493	2412
5	2321	2140	1909	2008	2612	2280	2345	2462	2417	2459	2510	2411
6	2289	2129	1912	2098	3127	2646	2762	2824	2676	2543	2506	2382
7	2233	2151	2132	2307	3284	2835	2780	2962	2850	2707	2774	2412
8	2358	2484	2264	2556	3283	3026	2876	3055	3046	2756	2914	2508
9	2460	2657	2459	2757	3503	3143	3116	3168	3170	2800	2971	2610
10	2523	2832	2667	2845	3551	3134	3125	3155	3222	2854	3084	2747
11	2595	2945	2709	2826	3488	3168	3174	3164	3194	2806	3078	2819
12	2731	2988	2658	2894	3424	3081	3184	3163	3088	2788	3019	2849
13	2702	2951	2634	2756	3496	3069	3310	3249	3095	2750	2946	2840
14	2716	2930	2516	2806	3507	3006	3322	3228	3140	2721	2989	2799
15	2666	2897	2487	2836	3595	2941	3395	3357	3059	2701	2899	2757
16	2304	2691	2367	3133	3694	3064	3156	3144	2955	2543	2513	2448
17	2241	2356	2067	2824	3299	3017	3112	3151	2967	2464	2522	2425
18	2267	2317	2062	2416	3321	2809	2981	3033	2886	2406	2553	2343
19	2252	2341	2139	2368	3268	2658	2873	2895	2859	2426	2633	2359
20	2338	2266	2131	2346	3231	2524	2803	2842	2849	2414	2616	2422
21	2431	2341	2110	2418	3093	2451	2702	2703	2751	2434	2679	2478
22	2425	2385	2086	2344	2996	2321	2600	2628	2694	2389	2660	2462
23	2392	2386	2041	2268	2942	2239	2515	2591	2598	2403	2706	2457

Figure 239. 2035 Average Headroom (MW) by Month and Hour P06 West of Hatwai

Average Headroom (MW) by Month and Hour
P06 West of Hatwai

2035 Topology

PT Hour Ending	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	1393	1092	1010	1397	1942	1484	1680	1791	1773	1726	1668	1613
1	1489	1183	1089	1440	2089	1460	1688	1891	1866	1879	1733	1657
2	1535	1279	1148	1384	2078	1432	1665	2031	1858	1952	1832	1723
3	1552	1318	1187	1431	2059	1512	1663	2116	1892	1949	1862	1753
4	1525	1303	1178	1434	2112	1471	1681	2164	1918	1989	1872	1764
5	1449	1241	1218	1381	2120	1693	1932	2076	1933	1944	1853	1707
6	1407	1242	1233	1606	2832	2179	2374	2455	2337	2094	1816	1672
7	1362	1364	1510	1947	3049	2619	2452	2630	2518	2178	2206	1733
8	1546	1782	1692	2123	3245	2793	2766	2827	2745	2326	2243	1836
9	1620	2081	1901	2467	3355	2830	2850	2908	2825	2427	2477	2002
10	1707	2196	2083	2550	3368	2908	2865	2879	2898	2494	2593	2170
11	1797	2364	2168	2595	3317	2843	2899	2880	2920	2522	2590	2262
12	1950	2480	2105	2689	3287	2947	2912	2825	2728	2448	2530	2330
13	1924	2553	2043	2714	3290	2889	2920	2868	2658	2385	2433	2310
14	1932	2547	1958	2747	3337	2984	3032	2862	2780	2313	2362	2280
15	1863	2544	1937	2701	3465	2857	3040	3012	2720	2296	2328	2218
16	1529	2256	1867	2789	3488	2918	2888	2837	2578	2139	1984	1821
17	1437	1694	1564	2388	2956	2564	2754	2737	2466	2048	2021	1813
18	1459	1641	1508	1998	2941	2269	2683	2544	2344	1904	2019	1663
19	1444	1690	1635	1943	2855	2121	2541	2446	2296	1920	2055	1683
20	1539	1686	1710	1935	2803	1959	2467	2375	2327	1956	2148	1754
21	1618	1752	1656	2008	2643	1849	2357	2255	2321	1974	2186	1819
22	1602	1722	1609	1821	2546	1698	2105	2121	2196	1924	2132	1799
23	1572	1754	1527	1765	2506	1625	1993	2100	2105	1955	2124	1805

Figure 240. 2027 Average Headroom (MW) by Month and Hour P71 South of Allston

Average Headroom (MW) by Month and Hour
P71 South of Allston

2027 Topology

PT Hour Ending	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	1788	1970	2191	2537	2279	1949	1835	1655	1938	1955	1726	1655
1	1953	2087	2316	2515	2317	2091	2012	1944	2143	2064	1857	1796
2	2157	2189	2374	2500	2343	2186	2096	2098	2268	2204	1990	1933
3	2226	2211	2462	2521	2358	2225	2162	2187	2357	2277	2109	2036
4	2250	2221	2457	2552	2395	2223	2215	2239	2382	2265	2135	2073
5	2180	2099	2265	2495	2513	2545	2561	2257	2373	2146	1949	1962
6	1971	1984	2106	2674	2943	2848	2824	2668	2755	2131	1787	1625
7	1717	2010	2309	2853	2988	2840	2869	2800	2910	2540	2166	1555
8	1862	2330	2633	2895	2991	2930	2905	2921	2941	2714	2416	1703
9	1971	2581	2776	3050	3063	2924	2860	2872	2912	2790	2618	1939
10	2103	2757	2916		2938	2914	2812	2790	2938	2832	2781	2127
11	2242	2853	3051		2985	2992	2780	2782	2975	2800	2854	2298
12	2415	2861	3011		2955	2962	2664	2742	2917	2828	2854	2434
13	2462	2840	3010		3051	2888	2545	2641	2896	2800	2826	2410
14	2481	2892	3065		3018	2925	2364	2566	2896	2774	2850	2451
15	2479	2868		3079	2997	2901	2293	2425	2735	2822	2683	2299
16	2117	2844	3074	3075	3008	2888	2129	2154	2557	2412	1974	1720
17	1935	2551	2861	2923	2873	2645	1835	1808	2296	2036	1870	1486
18	1797	2464	2788	2820	2711	2395	1532	1473	2038	1988	1844	1326
19	1709	2398	2770	2781	2708	2259	1504	1487	2050	1938	1932	1320
20	1764	2473	2794	2836	2729	2339	1621	1627	2195	2066	2065	1434
21	1772	2473	2754	2828	2691	2398	1862	1752	2239	2103	1993	1492
22	1856	2448	2699	2921	2650	2352	1917	1909	2431	2282	2113	1664
23	1982	2454	2735	2884	2661	2371	2161	2083	2508	2401	2191	1808

Figure 241. 2035 Average Headroom (MW) by Month and Hour P71 South of Allston

Average Headroom (MW) by Month and Hour
P71 South of Allston

2035 Topology

PT Hour Ending	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	1901	2185	2518	2821	2260	2069	2021	1864	2246	2178	1980	1944
1	2097	2325	2626	2847	2310	2201	2237	2181	2441	2452	2168	2109
2	2240	2360	2743	2875	2337	2280	2326	2349	2572	2529	2323	2265
3	2301	2410	2832	2914	2372	2340	2383	2415	2629	2609	2419	2320
4	2285	2395	2758	2852	2393	2339	2476	2462	2625	2549	2393	2361
5	2168	2295	2590	2878	2547	2620	2818	2509	2575	2317	2221	2161
6	1956	2070	2415	3098	3031	3042	3250	2946	2918	2353	2034	1871
7	1785	2226	2680	3242	3185	3155	3305	3154	3146	2466	2477	1872
8	2019	2760	2865	3252	3263	3208	3293	3238	3258	2737	2484	1981
9	2219	3052	3013	3378	3307	3294	3308	3233	3212	2805	2775	2155
10	2312	3251	3205	3368	3346	3303	3260	3194	3239	2944	2938	2331
11	2475	3305	3320	3458	3346	3310	3248	3220	3211	3018	3070	2529
12	2639	3310	3375	3508	3334	3312	3183	3091	3169	3055	3099	2681
13	2712	3371	3345	3494	3369	3320	3023	2998	3111	2987	3066	2720
14	2709	3339	3253	3523	3377	3314	2831	2946	3065	3025	3098	2685
15	2736	3332	3414	3529	3366	3293	2572	2670	2951	2925	2965	2549
16	2363	3248	3259	3357	3354	3200	2326	2433	2770	2752	2599	2018
17	2143	2826	3280	3127	3056	2784	2049	2009	2556	2482	2420	1783
18	2032	2758	3148	3046	2751	2500	1736	1732	2270	2290	2377	1557
19	1937	2741	3117	3056	2763	2375	1606	1689	2287	2216	2295	1484
20	2002	2804	3123	3035	2786	2421	1743	1822	2376	2227	2346	1601
21	1978	2805	3128	3105	2761	2488	1968	1931	2494	2270	2377	1702
22	2045	2849	3099	3118	2752	2430	2161	2169	2656	2525	2488	1912
23	2166	2931	3140	3067	2698	2441	2350	2320	2751	2664	2634	2081

Figure 242. 2027 Average Headroom (MW) by Month and Hour Pth-BPA-North of Pearl

Average Headroom (MW) by Month and Hour
_Pth-BPA-North of Pearl

2027 Topology

PT Hour Ending	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	1127	985	1045	694	1106	1272	1149	1212	1256	1325	1308	1048
1	1115	958	1008	611	1125	1218	1102	1100	1163	1305	1314	1068
2	1026	888	887	585	1148	1161	1090	1047	1110	1237	1261	1036
3	988	894	821	511	1131	1149	1064	1006	1048	1182	1203	993
4	962	900	772	494	1083	1132	1022	959	1014	1136	1163	949
5	943	933	805	519	907	765	706	884	928	1058	1203	957
6	911	925	766	196	254	222	240	451	437	822	1140	1020
7	848	699	412	41	151	136	92	232	173	369	596	845
8	597	344	173	20	88	95	42	96	85	204	338	591
9	520	200	79	7	41	47	32	62	64	165	170	402
10	443	87	24	5	17	16	27	65	68	117	93	269
11	376	35	13	0	3	13	36	54	50	110	30	164
12	273	29	9	0	0	41	77	50	59	116	33	98
13	243	36	10	0	0	41	113	90	69	132	74	156
14	240	35	10	0	10	41	151	99	68	167	77	169
15	264	33	7	0	22	62	194	167	138	229	151	292
16	541	109	13	3	63	93	287	316	321	514	762	656
17	559	317	162	87	299	372	501	539	589	735	712	664
18	512	256	213	232	740	717	730	777	737	736	646	644
19	566	240	165	227	709	793	791	760	716	714	572	663
20	608	246	173	202	635	721	752	721	647	713	549	645
21	695	282	227	188	606	704	666	740	720	800	658	676
22	772	403	339	259	615	770	715	800	727	834	718	701
23	862	464	430	332	738	864	738	837	801	906	807	777

Figure 243. 2037 Average Headroom (MW) by Month and Hour Pth-BPA-North of Pearl

Average Headroom (MW) by Month and Hour
_Pth-BPA-North of Pearl

2035 Topology

PT Hour Ending	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	2455	2294	2196	1677	2225	1984	1848	1910	1863	2299	2253	2272
1	2406	2272	2172	1651	2249	1911	1783	1757	1761	2156	2201	2266
2	2343	2245	2085	1665	2238	1914	1777	1684	1701	2113	2129	2212
3	2319	2213	2019	1637	2233	1881	1763	1662	1669	2051	2069	2196
4	2316	2239	2021	1586	2163	1830	1676	1608	1645	2048	2067	2155
5	2326	2246	2026	1603	1961	1482	1305	1500	1580	2066	2106	2226
6	2315	2276	1961	1272	1314	861	571	852	1078	1788	2066	2272
7	2193	1948	1536	901	1297	799	415	702	811	1538	1459	2033
8	1854	1428	1265	766	1124	650	285	523	639	1264	1274	1786
9	1692	1165	1018	628	981	543	241	438	560	1212	1049	1612
10	1622	914	816	477	875	381	245	395	513	1128	877	1469
11	1518	697	716	331	663	395	214	363	450	1083	812	1331
12	1427	653	698	308	534	374	289	404	482	1062	841	1260
13	1408	700	723	210	473	356	353	445	436	1099	856	1259
14	1433	758	740	297	553	454	461	480	466	1131	856	1328
15	1416	820	690	294	642	568	621	610	560	1152	909	1447
16	1707	1095	747	419	869	629	789	859	785	1332	1329	1821
17	1767	1612	1158	870	1330	1115	1147	1218	1168	1520	1375	1844
18	1729	1647	1376	1407	1862	1597	1475	1413	1407	1639	1278	1873
19	1782	1591	1294	1386	1919	1682	1649	1542	1381	1663	1350	1957
20	1799	1523	1218	1359	1923	1597	1567	1401	1302	1683	1393	1928
21	1903	1546	1235	1319	1875	1504	1431	1392	1317	1791	1478	1936
22	2003	1591	1330	1268	1737	1485	1411	1401	1340	1788	1531	1929
23	2096	1632	1429	1314	1738	1581	1401	1465	1393	1845	1603	1984

L.4 Seasonal and Annual Transmission Constraint Frequency Analysis

To complement the headroom assessment, transmission constraint frequency was evaluated using an 80% TTC utilization threshold, with hours exceeding 80% of Total Transfer Capability (TTC) classified as constrained. Constraint frequency provides an indication of how often a transmission interface operates near its transfer capability and serves as a proxy for potential constraint risk and reduced availability of non-firm transmission service.

Results were summarized on both a seasonal and annual basis to identify:

- Interfaces that experience recurring constrain throughout the year.
- Seasonal patterns that may be associated with changes in load, hydro conditions, renewable generation output, or regional energy transfers.
- The effectiveness of planned transmission upgrades in reducing the frequency of highly used operating conditions.
- Transmission interfaces that may warrant additional monitoring or future infrastructure investment.

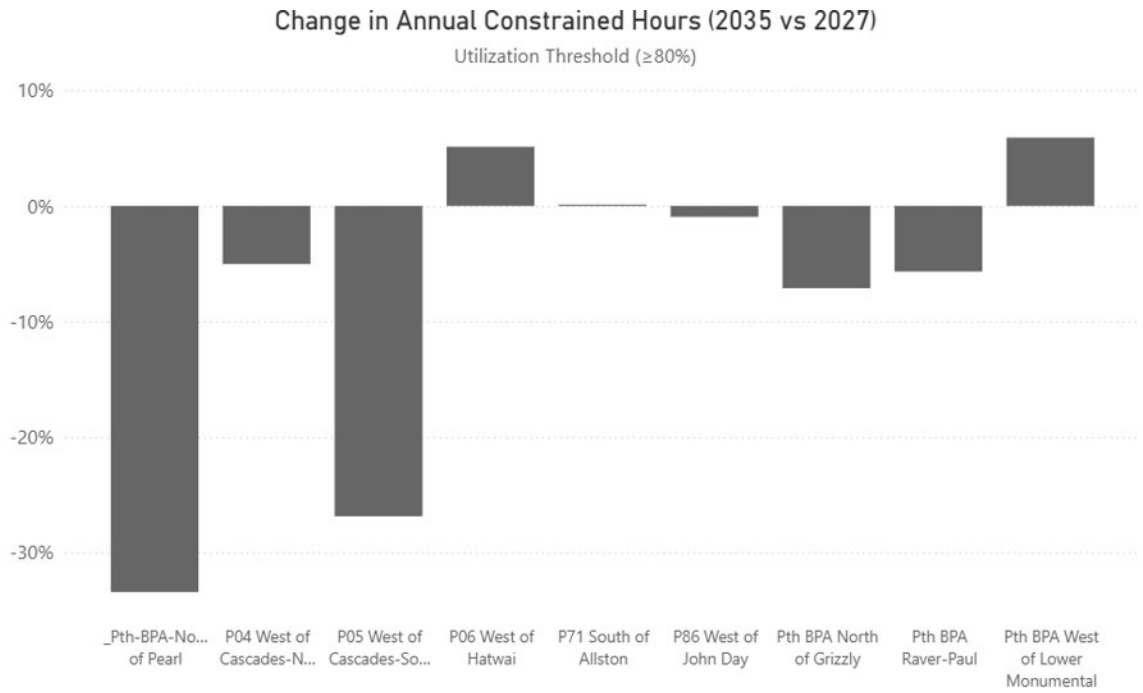
Figure 244 and Figure 245 below compare the percentage of constrained hours across all evaluated WECC paths and BPA flowgates under the 2027 and 2035 topology scenarios. Higher percentages indicate increased utilization and a greater likelihood of constraint-related impacts, while lower percentages indicate greater operational flexibility and available transfer capability.

Figure 244. Hours Over Use Threshold

% of Hours Over Utilization Threshold (>=80%)

Season	Winter		Spring		Summer		Fall	
Name	2027 Topology	2035 Topology	2027 Topology	2035 Topology	2027 Topology	2035 Topology	2027 Topology	2035 Topology
_Pth-BPA-North of Pearl	40%	4%	66%	21%	49%	29%	42%	9%
P04 West of Cascades-North	7%	0%	12%	0%	1%	0%	0%	0%
P05 West of Cascades-South	36%	0%	34%	1%	30%	0%	9%	0%
P06 West of Hatwai	0%	5%	0%	10%	0%	5%	0%	0%
P71 South of Allston	0%	0%	0%	0%	0%	0%	0%	0%
P86 West of John Day	1%	0%	2%	0%	1%	0%	0%	0%
P87 West of McNary	0%	0%	0%	0%	0%	0%	0%	0%
P88 West of Slatt	0%	0%	0%	0%	0%	0%	0%	0%
Pth BPA North of Grizzly	10%	0%	7%	0%	7%	0%	5%	0%
Pth BPA North of Hanford	0%	0%	0%	0%	0%	0%	0%	0%
Pth BPA Raver-Paul	3%	0%	9%	0%	11%	0%	0%	0%
Pth BPA West of Lower Monumental	7%	23%	2%	9%	0%	1%	0%	0%

Figure 245. Change in Annual Constrained Hours (2035 to 2027)



L.4.1 Key Findings

- Planned Transmission Upgrades Significantly Reduce Constraint Risk:
  - Planned transmission additions substantially reduced utilization across most evaluated WECC paths and BPA flowgates.
  - The greatest reductions is observed on North of Pearl (-33% annual hours) and West of Cascade South (-27% annual hours).
- North of Pearl Remains the Most Significant Limitation: North of Pearl remains the highest constrained path persisting across both scenarios.
  - With network upgrades, constrained hours decline from approximately 49% of annual hours to 16%, but continues to present the highest risk to non-firm transmission service
  - Constraint risk is concentrated between March and September, with the highest frequency occurring during the spring and summer months.
  - BPA's proposed Keeler-Pearl #2 500 kV line is identified as a critical project to reduce constraint risk and address capacity limitations on this interface.
  - Solar Driven Risk Patterns: On North of Pearl, the highest frequency of constrained hours occurs between 8:00 AM and 4:00 PM, driven by northbound transfers associated with abundant, low-cost California solar generation.
- Network Expansion Alters Regional Power Flow Patterns:
  - While most interfaces experience reduced utilization, West of Lower Monumental and West of Hatwai experience higher utilization following planned network upgrades due to increased east-to-west flows.

  - These results indicate changing dispatch patterns and increased utilization of these corridors to deliver energy from resource-rich areas to regional load centers
- Remaining 11 paths Exhibit limited Long-Term Constraint Risk:
  - Excluding North of Pearl, the remaining 11 evaluated WECC paths and BPA flowgates experience infrequent constrained conditions under the 2035 topology.
  - These results indicate adequate transfer capability across these interfaces and suggest limited long-term risk to non-firm transmission service under projected 2035 system conditions.

L.4.2 IRP Planning Considerations

The headroom analysis across the evaluated WECC paths and BPA flowgates provides critical insights into the projected transmission utilization and constraint risk under 2035 system conditions. The comparative assessment between the 2027 topology and the 2035 planned network topology clearly demonstrates the value of transmission infrastructure investment in alleviating constraint risk and reducing non-firm transmission curtailment risk.

While North of Pearl remains, a persistent constraint risk requiring targeted infrastructure solutions such as the Keeler-Pearl #2 500 kV line, the majority of evaluated interfaces show significantly reduced constraint risk with planned upgrades in place.

The results are intended to support planners in prioritizing transmission investments and refining non-firm transmission risk assessments within the 2026 IRP evaluation framework.

L.5 Transmission Constraints IRP Analysis

L.5.1 Overview

The goal for this study and analysis is to forecast hours of constraint on twelve BPA paths and flowgates every hour for an entire year. The motivation for forecasting constrained hours is to project the risk of non-firm transmission products being curtailed in future operating years. The results of this analysis will be used as inputs to the IRP process to help inform decisions around transmission product availability.

L.5.2 Setup

The study was conducted using Hitachi GridView Production Cost Modeling software. The base case used is the 2035 WestTEC version 2.0. All outputs and results are forecasts for the 2035 operating year.

L.5.3 Methodology

The twelve BPA paths and flowgates identified for analysis are: West of Cascades North, West of Cascades South, West of Hatwai, South of Allston, West of John Day, West of McNary, West of Slatt, North of Pearl, North of Grizzly, North of Hanford, Raver Paul, and West of Lower Monumental. For this analysis a path is defined as “constrained” when the megawatt flow on the path is greater than or equal to 80% of its posted total transfer capability (TTC).

A 12x24 heatmap was generated from the output path flow and TTC data representing every hour of each day for every month. If any of the twelve paths studied is constrained the entire hour is counted as a constrained hour. The value inside of each cell on the heatmap is the total constrained hours divided by the total hours that cell represents.

L.5.4 Results

Three (3) paths represented 99% of all identified constrained hours: West of Hatwai, West of Lower Monumental, and North of Pearl. West of Hatwai counted 415 constrained hours, West of Lower Monumental counted 666 constrained hours, and North of Pearl counted 1300 constrained hours. The months with the greatest frequency of constrained hours are early spring to summer or February until September. The hours of the day with the greatest frequency of congestion are 0700 to 1600.

Appendix M Renewable Portfolio Standard (RPS) Implementation Plan (RPIP)

Pursuant to Oregon Revised Statutes (ORS) 469A.052 and 469A.075, PGE submits the enclosed 2026 Renewable Portfolio Standard (RPS) Implementation Plan (RPIP) for the period 2027 through 2031. Due to the passage of HB 3161, on December 28, 2023 the Oregon Public Utility Commission (OPUC or Commission) issued Order No. 23-484 to repeal OAR 860-083-0400, which previously detailed RPIP filing requirements. Per HB 3161, RPIP filings are now included in Integrated Resource Plan (IRP) filings, which will occur every three years in accordance with OAR 860-090-0030(1).

This 2026 RPIP for years 2027-2031 is based primarily on existing qualifying renewables resources currently known or anticipated to be part of PGE's generating portfolio during this time, as well as on new resource needs projected in PGE's 2026 joint Clean Energy Plan/Integrated Resource Plan (CEP/IRP).

ORS 469A.052 imposes the requirement that at least 27% of electricity sold by a large utility to retail electricity consumers must come from qualifying resources in each of the calendar years 2025 through 2029. From 2030 through 2034, the percentage increases to 35 percent. ORS 469A.075 requires electric companies subject to ORS 469A.052 to develop an implementation plan (RPIP) for meeting the requirements of the standard and file the plan with the OPUC.

For planning purposes, PGE intends to meet its RPS obligations, as demonstrated in this RPIP, primarily with bundled RECs from existing resources, as well as 20% unbundled RECs in alignment with recent RPS compliance demonstrations. Recent RPS compliance demonstrations have used unbundled RECs for flexibility and to preserve the REC bank. Pursuant to ORS 469A.052, and 469A.075 requirements, the following sections provide details of the 2026 RPIP.

M.1 Annual Targets for Acquisition and Qualifying Electricity Use

PGE's annual megawatt target to comply with the applicable RPS based on the reference forecast of electricity sales to Oregon retail electricity customers is:

- 2027 – 5,868,297 MWh
- 2028 – 6,185,101 MWh
- 2029 – 6,426,506 MWh
- 2030 – 8,659,269 MWh
- 2031 – 9,034,731 MWh

For more detailed information see CONFIDENTIAL excel workbook file SIR response for RPIP, tab "Annual Compliance".

M.2 Estimated Cost of Meeting Annual Targets

The estimated cost of meeting the annual targets, including the cost of transmission, the cost of firming, shaping and integrating qualifying electricity, the cost of alternative compliance payments, and the cost of acquiring renewable energy certificates (RECs).

a. RPIP SIR file, tab "Inc Cost Summary" provides the estimated cost of meeting the annual RPS compliance targets for the period between 2027 and 2031. In accordance with Commission Order No. 21-487 the cost of transmission, firming, shaping, and integrating qualifying electricity is embedded in the calculation of the incremental cost by resource provided in RPIP SIR file, tab "Inc Cost by Resource".

b. PGE does not plan to use Alternative Compliance Payments (ACP) in any of the compliance years, 2027 through 2031. A forecast of the cost of using unbundled RECs for compliance is provided in RPIP SIR file, tab "Inc Cost Summary".

c. Description of base case incremental cost calculations: The base case incremental cost was determined by multiplying the above-market nominal levelized cost in $/MWh associated with each of the qualifying renewable resources expected to be used for RPS compliance between 2027 and 2031 with the resource's expected annual generation to meet the compliance requirement.

d. Incremental cost of RECs generated in each year: RPIP SIR file, tab "Inc Cost of RECs Gen" provides the incremental cost of RECs generated in each year of the 2027-2031 compliance period.

e. Sensitivities for different gas price scenarios: RPIP SIR file provides sensitivities for low and high gas price scenarios in addition to the reference base gas price scenario.

M.3 Cost of New Resources Not Included in 2026 RPIP

The cost of new resources in the 2026 RPIP filing:

PGE estimates the incremental cost of all new resources. RPIP SIR file, tab "Inc Cost Summary," lists new resources including Biglow Hybrid – Solar and Wheatridge Hybrid – Solar, which were procured in 2026 (and therefore considered to be existing resources) and are anticipated to be online by 2028.

On a planning basis, though RPS compliance is demonstrated for 2027-2031 with existing resources, PGE also includes new resource additions identified in IRP analysis. These are described in the Major Changes and New Resources section below.

M.4 Compliance

Explanation of how the 2026 RPIP complies with any conditions specified in previous Commission acknowledgments of IRPs, requests for Production, or RPIPs:

Commission Order No. 10-173 acknowledged PGE's first implementation plan (i.e., 2011-2015 RPIP), filed December 31, 2009. That order contained no conditions; however, the Order recommended the development of a standardized template for the 2011 filing. OPUC Staff and the Parties jointly developed a template in 2011 and it remains the format that PGE uses for its RPIPs.

Commission Order No. 10-457 acknowledged PGE's 2009 IRP and 2010 Addendum, with conditions. No conditions pertain directly to RPIP filing requirements. PGE filed its Draft 2013 IRP on November 22, 2013.

Commission Order No. 12-271 acknowledged PGE's 2013-2017 RPIP, filed December 28, 2011. The order required PGE to not include shaping costs in its next RPIP (2015-2019 RPIP), with which we have complied.

Commission Order No. 14-265 acknowledged PGE's 2015-2019 RPIP, filed December 31, 2013. The Order directed PGE to include a scenario in future RPIPs under the reference case that assumes PGE uses unbundled RECs equal to 20% of its annual requirement, assuming an unbundled REC price equal to the weighted average price paid for unbundled RECs used in its last RPS compliance report for each year analyzed in the RPIP.

Commission Order No. 16-157 acknowledged PGE's 2017-2021 RPIP, filed December 31, 2015. The Order directed PGE to answer additional questions related to the passage of SB 1547. Those issues were addressed in Docket No. UM 1788.

Commission Order No. 18-185 acknowledged PGE's 2019-2023 RPIP, filed December 29, 2017, and supplemented on February 2, 2018. The Order contained no conditions.

Commission Order No. 19-447 adopted Staff's recommendation to streamline the 2020 RPIP filings (for PGE and PacifiCorp), waiving the requirements under OAR 860-083-0400(2)-(5) for the 2021-2025 compliance period.

Commission Order No. 20-135 acknowledged PGE's 2021-2025 RPIP, filed December 31, 2019. The Order contained no conditions.

Commission Order No. 21-487 adopted Staff's recommendation to streamline the 2022 RPIP filings (for PGE and PacifiCorp), waiving the requirements under OAR 860-083-0400(2)-(5) for the 2023-2027 compliance period.

Commission Order No. 22-112 acknowledged PGE's 2023-2027 RPIP, filed December 30, 2021. The Order contained no conditions.

Due to the passage of HB 3161, on December 28, 2023 the Oregon Public Utility Commission (OPUC or Commission) issued Order No. 23-484 to repeal OAR 860-083-0400. At the time of this filing, minimum RPIP requirements are detailed in ORS 469A.075(2). This 2026 RPIP reflects analysis similar to the last RPIP filing, and compliance with requirements of the statute.

M.5 Major Changes and New Resources

Major changes and new resources, and how they would change the Companies' compliance strategy between now and the next RPIP filing scheduled for 2029.

This 2026 RPIP includes existing qualifying renewable resources that are known to be part of PGE's base generating portfolio as of 2026. This includes recent procurements anticipated to be online in 2028 of 125 MW of solar at Biglow and 240 MW of solar at Wheatridge. The battery portions of these new hybrid additions to PGE's portfolio are not relevant for RPS.

The existing portfolio of generating resources, with 20% unbundled RECs are sufficient to demonstrate RPS compliance in 2027-2031.

However, in an effort to align with planning, PGE also includes additional renewable builds aligned with the 2026 CEP/IRP near-term Action Plan. For this RPIP analysis, PGE has conservatively modeled the lower end of the Action Plan range, which aligns with builds in the Continued Progress portfolio. These new builds from IRP modeling included in the RPIP are:

- Montana standalone wind: 143 MW added in 2030.
- SE Washington standalone wind: 400 MW added in 2030.
- Oregon Gorge hybrid: 1000 MW of wind and 667 MW of solar added in 2030 (battery portion of hybrid not relevant for RPS).
- Montana hybrid: 51 MW of wind and 34 MW of solar added in 2030, with additional 99 MW of wind and 66 MW of solar added in 2031 (battery portion of hybrid not relevant for RPS).
- SE Washington hybrid: 400 MW of wind and 267 MW of solar added in 2031 (battery portion of hybrid not relevant for RPS).

See Chapter 2 of the 2026 CEP/IRP for more on PGE's near-term activities identified in planning.

The new additional qualifying renewable resource builds identified by IRP modeling are not expected to materially change PGE's compliance strategy between this filing and the next RPIP filing.

Appendix N Renewable Energy Certificates Discussion

In response to the Public Utility Commission of Oregon (OPUC or Commission) Direction #6 in LC 80 Order No. 24-096,[328] PGE described the future requirements of demonstrating compliance with HB 2021 emissions targets in the January 2026 Roundtable[329] and includes the following discussion to clarify information about emissions reductions and clean energy.

PGE reports emissions to the Oregon Department of Environmental Quality (ODEQ) based on defined rules in OAR Chapter 340, Division 215. As part of the annual emissions report, PGE calculates the total sources of energy from generation, power purchased via long- and short-term contracts, and power purchased from the market, then removes wholesale sales to arrive at the total volume of resources that served retail customers (inclusive of transmission loss considerations). All generating resources, including emitting and non-emitting, are required to be reported to ODEQ. This annual report forms the basis for compliance demonstration with the HB 2021 emissions targets for operations in years 2030, 2035, and 2040. The DEQ emissions report reflects underlying generation resources emissions according to fuel type and known specifications and operations, across the given retail load report year report year used to serve retail load.

HB 2021 and the rules addressing emissions reporting and compliance are distinct from Oregon's clean energy programs such as the Renewable Portfolio Standard (RPS). For the RPS, renewable energy certificates (REC) are used for compliance, as they support contractual claims to renewable energy but do not support emissions compliance. As memorialized in Order No. 24-002, the Commission stated: "The text and context of the statute point unambiguously to the conclusion that compliance with HB 2021's emissions reductions requirements need not be demonstrated through REC retirement. HB 2021 requires us to consider and report the emission attributes of the underlying generating resource, and as such, emissions reported for compliance with HB 2021 can only reflect the underlying generating resource."[330] Thus, the considerations for RECs are not pertinent to HB 2021. This perspective is also shared by California Air Resources Board (CARB) that emissions and REC accounting are separate and distinct accounting approaches.[331]

Emissions accounting for HB 2021 aims to reflect the physical impact of generation. It requires that PGE calculate emissions from generation and not the emissions avoided by adding emissions-free generation. Separate REC-based accounting aims to capture procurement strategy, such as contractual choices and power purchase agreements, from a statutorily defined subset of generation options, some of which emit greenhouse gases when generating. The REC method can be useful for capturing customer-specific purchasing decisions, such as RECs purchased by the voluntary market to demonstrate support of renewable power. However, the ODEQ emissions accounting rules define a different methodology that reflects emissions associated with generating

[328] https://apps.puc.state.or.us/orders/2024ords/24-096.pdf.
[329] Appendix Section C.2.
[330] https://apps.puc.state.or.us/orders/2024ords/24-002.pdf.
[331] https://stakeholdercenter.caiso.com/InitiativeDocuments/CAISO-GHG-Issue-Paper-CARB-Comment-Letter-July2025-signed.pdf.

resources and market purchases, while also requiring reporting of emissions-free generation as a check for total load served.

Both emissions regulations (such as HB 2021) and clean energy programs (such as the RPS) are complementary environmental policies that aim to achieve a cleaner energy system, but do so through different means. ODEQ GHG emissions accounting requirements and REC accounting are separate and distinct methodologies for different programs and purposes and should not be conflated. There is no double counting of resources and emissions within a given accounting framework, and the fact that one system exists does not mean that the other must fit within it or operate consistently with it.

Appendix O Grants

The Oregon Public Utility Commission directed PGE to include a report on federal grants relevant to resource procurement and transmission development. This section outlines the federal grant programs PGE has engaged with, including awarded grants, denied grants, grants still in application phase, instances where PGE withdrew from the application process and recent terminations, initiated by the current administration. Note: Grant Identification (GID) refers to PGE internal numbering system.

O.1 Grants in Execution Phase

O.1.1 Confederated Tribes of Warm Springs and Portland General Electric Regional 500kV Transmission Innovative Project (GID05)

Project Partners

Confederated Tribes of the Warm Springs (CTWS) Prime, PGE subrecipient

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 help offset 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.

Area of Focus

Grid modernization, reliability, decarbonization

Award to PGE

$245M, subject to final approval by DOE.

O.1.2 Critical Sectors Job Quality Tier 2 Implementation Grant (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 Oregon Clean Energy Workforce Coalition's Jobs for a Clean Energy Future seeks to increase the representation of women and people of color within the clean energy sector by focusing on the Good Jobs Principles of Recruitment and Hiring, Skills and Career Advancement. The program will

leverage an industry-led coalition of nearly 60 participants from across the state who are dedicated to building the equitable and inclusive clean energy workforce that will meet the needs of today and will expand to meet the needs of the future.

Area of Focus

Workforce development

Award to PGE

$539,476

O.1.3 Quality Green Jobs Regional Challenge (Jobs for the Future) (GID14)

Project Partners

Oregon Clean Energy Coalition members (PGE applied on behalf of the Oregon Clean Energy Coalition)

Description

Climate Resilient Employees for a Sustainable Tomorrow (CREST) is a multi-year, grant-funded initiative of the Ares Charitable Foundation. The Quality Green Jobs Regional Challenge (the Challenge) is a CREST initiative led by Jobs for the Future (JFF). Over a four-year period, the Challenge will support subrecipients across the United States as they design and implement regional quality green job strategies.

The primary goals of the Challenge:

- Offer green job training and placement in quality jobs to 25,000 individuals in diverse regions across the United States and U.S. territories
- Pilot strategies intended to disrupt occupational segregation in the green economy with a focus on racial, gender, and systemic inequities
- Help 100,000 people gain a deeper understanding of regional climate-related challenges and opportunities in the labor market.

Areas of Focus

Workforce development

Award to PGE

$10,000 (first phase); $75,000 (second phase); $750,000 (third phase).

O.1.4 Proactive Human-Machine Teaming Enabled Cybersecure Technologies (PROTECT) - Cybersecurity, Energy Security, and Emergency Response (CESER) (GID25)

Project Partners

Pacific Northwest National Laboratory (PNNL) (Prime), University of Central Florida (UCF), New Jersey Institute of Technology (NJIT), Siemens Technology, PGE, and Florida Power & Light

Description

In PROTECT, the project team will develop, validate, and field demonstrate novel PROTECT algorithms and tools for enabling next-generation cybersecurity measures at the DER Operations Center (e.g., DMS/ADMS, DERMS, Utility/DER Control Center), for high-DER penetrations (up to 100% DER penetration).

Area of Focus

Cybersecurity

Award to PGE

$200K

O.1.5 SETO Lab Cal Sensor-MAP (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 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

Award to PGE

$0 PGE In-kind only

O.1.6 Community Renewal Energy Grant Program (CREP), Salem Smart Power Center (GID47)

Project Partners

City of Salem (Prime), PGE

Description

This project will repower the Salem Smart Power Center ("SSPC") facility with a new 3.9 MW/7.8 MWh Battery Energy Storage System ("BESS") and retire the existing BESS. The new BESS will be a key asset in supporting the new City of Salem Community Microgrid and strengthen the City of Salem's new resiliency center. The City of Salem Microgrid provides resiliency for the city's new public works operations facility, various city shops and nearby single and multi-family dwellings. Power supplied from the microgrid also provides power to the City's level 1 and level 2 EV charging units.

Area of Focus

Grid Resilience

Award to PGE

$1M

O.1.7 PNNL-Grid Atlas Battelle (GID49)

Project Partners

Pacific Northwest National Laboratory (PNNL) prime, National Lab of the Rockies (NLR) and PGE

Description

Pacific Northwest National Laboratory (PNNL) and the National Lab of the Rockies (NLR) are partnering to develop the new Distribution Grid Atlas—a publicly available catalog of realistic, geographically relevant, representative distribution feeder models without sensitive geographic information, customer data, or disclosure of utility models.

Area of Focus

Grid Resilience

Award to PGE

$0, PGE in-kind

O.2 Awards in Negotiation

O.2.1 Hydropower Incentives- (GID07, GID37, GID38, GID40)

Project Partners

PGE (Prime), 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% cost share required).

Area of Focus

Hydropower operations

Award to PGE

$11.3 million from US Department of Energy for 4 sites

Note

At this time, PGE and DOE have executed conditional awards for both Faraday and Blue Heron projects. DOE has not provided additional guidance on the Pelton-Rd Butte and Willamette Falls projects.

O.2.2 North Plains Connector - 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.

Area of Focus

Grid modernization

Award to PGE

PGE is a subrecipient on this award, but the terms of the resulting agreement are still pending.

O.2.3 ODOE Grid Resilience (GID55)

Project Partners

Oregon Department of Energy (ODOE), prime, PGE

Description

The Summit-Meadows circuit is located within High Fire Risk Zone (HFRZ) 1, functionally serving as the eastern terminal end of PGE's Eastern Service Territory. The project will re-route the Summit-Meadows 13kV mainline to Mt Hood Meadows as an underground line, following the US-26 and OR-35 corridors. The proposed underground route is approximately 10 miles. Once the new lines

are energized, approximately 2.7 miles of overhead conductor and related equipment will be removed.

Area of Focus

Undergrounding power lines

Award PGE

TBD

O.3 Full Applications Submitted

O.3.1 Collaborations Advancing Rapid Load Additions (CARLA): ODOE

Project Partners

Oregon Department of Energy (Prime), PGE, Compass Datacenters, Baringa, ORNL (MEGADC), Nira, and The Ray

Description

Oregon is experiencing rapid and concentrated demand growth driven by datacenters, AI workloads, domestic manufacturing, and electrification. The 12-month, DOE-funded CARLA project creates an integrated framework to accommodate large new loads faster while protecting affordability for residential and small commercial customers.

Area of Focus

Optimize load growth

Award to PGE

$213K

O.3.2 Geothermal with Confederated Tribes of Warm Springs (CTWS) - (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

Note

No further information from DOE since application submittal in Fall of 2024

O.3.3 Distribution System Operator with Virtual Power Plants, Dynamic Operating Envelope, and Competitive Market-Choice - Solar Technologies' Rapid Integration and Validation for Energy Systems (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

$3M

Note

PGE was selected for an interview, post application submittal in Oct 2024. No further action from DOE.

O.4 PGE Withdrew Participation

O.4.1 Renewable Hydrogen Production and Generation (GID04)

Description

PGE has withdrawn from this grant, effective June 4, 2025, given the exit of an essential project partner, challenging project economics for utility customers, and potential federal policy changes.

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.

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.

O.5 Grants Terminated by Federal Funders

O.5.1 Wheatridge Demonstration Project - (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 various 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 as thermal resources retire, the need to replace grid stabilizing services will increase.

Areas of Focus

Grid resiliency, grid modernization

Award to PGE

$1.5M

O.5.2 Accelerating and Deploying Grid Edge Computing - GRIP (GID02)

Project Partners

PGE (Prime), Oregon State University and 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% 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.

Area of Focus

Grid reliability, grid resiliency, grid modernization

Award to PGE

$50M

Note

DOE has notified PGE, requesting to re-engage with the commitments of this grant. Negotiations continue between both parties.

O.5.3 SmartGrid Advanced Load Management & Optimized Neighborhood (SALMON) (GID12)

Project Partners

PGE (Prime) National Renewable Energy Lab (NREL), Energy Trust and Clean Energy Partner (CEP) and Northwest Energy Efficiency Alliance (NEEA)

Description

Project will demonstrate and document the value of Distributed Energy Resources (DERs) as a grid resource for bulk system and distribution operations by developing a 1.4-mega-watt (MW) flexible load resource, retrofit approximately 580 buildings with a range of measures including smart thermostats, smart water heaters, solar with smart inverters, storage, and managed electric vehicle (EV) charging.

Area of Focus

Grid resilience

Award to PGE

$4.2M

O.5.4 Portland Bureau of Transportation: Park and Charge (GID13)

Project Partners

Portland Bureau of Transportation (PBOT) (Prime), 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.

Areas of Focus

EV Adoption

Award to PGE

$40K

O.6 Grants Not Awarded

O.6.1 Distribution Grid Modernization for Reliability and Wildfire Risk Reduction -(GID08)

Project Partners

PGE (Prime), 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 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)

O.6.2 Wildfire and All Hazards Modeling and Mitigation Consortium (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)

O.6.3 Operation and Planning Tools for Inverter-Based Resource Management and Availability for Future Power Systems (OPTIMA) (GID11)

Project Partners

WSU (Prime), 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 synchro phasors 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

O.6.4 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)

O.6.5 Mobile Batteries for Adaptive Resilience (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)

O.6.6 Western Bounty Transmission - (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

O.6.7 West Coast Real-Time Inertia Measurement Project (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)

O.6.8 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

O.6.9 Enhanced Wildfire Awareness Technologies and Visualization Platforms to Support Public Safety and Community Awareness Initiatives (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)

O.6.10 Bethel-Round Butte Middle Mile Fiber Project—NTIA (GID33)

Project Partners

PGE (Prime), 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)

O.6.11 Hydropower Incentives (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.

Area of Focus

Hydropower operations

Project Budget

$11 .3 million across multiple sites

O.6.12 Undergrounding Powerlines to Reduce Wildfire Risk in National Forests (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

O.6.13 Grid Copilot for an Electrified, Decarbonized & Empowering Grid (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)

O.6.14 Weavegrid—(GID62)

Project Partners

Weavegrid (Prime), PGE, Avista, PSE, PG&E, SCE, BGE, Xcel, Alabama Power, Georgia Power, TEP, PEPCO, Orange & Rockland, Eversource, Luma

Description

Managed EV charging to enhance grid resilience.

Area of Focus

Grid Resiliency, Grid Modernization

O.6.15 Agentic Al for Automated Interconnections—ConnectWerx (GID67)

Project Partners

ThinkLabs Al (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 Al models, evaluate results of Al 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

O.6.16 Carbon Optimization Framework for Energy Emissions (COFFEE) Grant (GID71)

Project Partners

PGE (Prime), 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)

O.6.17 Scale Smart Managed Charging and Enhance Grid Resilience through Enriched Grid Edge DERMS (GID72)

Project Partners

PGE (Prime), OSU

Description

Enrich PG E's Grid Edge Distributed Energy Resource Management System (DERMS) integrations to scale Smart Charge Management to more EVs in PG E'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

O.6.18 An Energy Resilience Planning Tool for PGE (GID73)

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. Statistical analysis 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)

O.6.19 Vegetation-based Ignition Risk Characterization and Comprehensive Near-term Wildfire Risk Mitigation (GID74)

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 minimizing the impact of PSPS on the communities.

Area of Focus

Grid Resilience

Project Budget

Advisory Committee Only

O.7 Close Out

O.7.1 Western-based Analysis of Distributed Battery Storage System Emission Benefits and Tradeoffs (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 (3) 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

Award to PGE

$0, PGE In-kind only and no cost share

O.7.2 Forecasting Load and Demand Response during Heat Waves through Large-Scale Sensing and Data Fusion (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

Award to PGE

$0, PGE In-kind only and no cost share

O.7.3 Stevens Institute (GID45)

Project Partners

Stevens Institute of Technology (SIT), University of Arizona (UA) and PGE

Description

Exploring Multidimensional Spatial-Temporal Hydropower Operational Flexibilities by Modeling and Optimizing Water-Constrained Cascading Hydroelectric Systems. Team will analyze potential approaches for maximizing the value of cascading hydroelectric (CHE) systems in providing a suite of operational flexibilities.

Area of Focus

Hydropower Operational Flexibility

Award to PGE

$200,000

O.7.4 Made in America Prize: Plentiful AI (GID60)

Project Partners

Plentiful AI (Prime), PGE

Description

The proposed project will utilize PGE datasets related to interconnection services (such as service-level load calculations, transformer ratings and loadings, and relevant design standards) and distribution system planning (such as hosting-capacity related information). PGE will work with the Plentiful.ai team to review existing internal data flows and seek advice and input on modifications to those processes that will ensure the project's success.

Area of Focus

Grid management

Award to PGE

$0, PGE in-kind only.

Appendix P Energy Trust of Oregon Methodology

Energy Trust of Oregon

PGE Energy Efficiency

2026 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 1,079 aMW of electricity. Additionally, Energy Trust has saved 114 million therms since gas efficiency programs began in 2003. Combined, this equates to more than 48 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 2015 to 2024, as shown in OPUC utility statistic books.[1]

Energy Trust, with support from PGE, serves residential, commercial and industrial customers in Oregon. In 2025, Energy Trust's service to PGE customers through energy efficiency programs achieved 32.1 aMW of electric savings achieving 97% of goal. Energy Trust achieved electric savings at a utility levelized cost of 0.042$/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

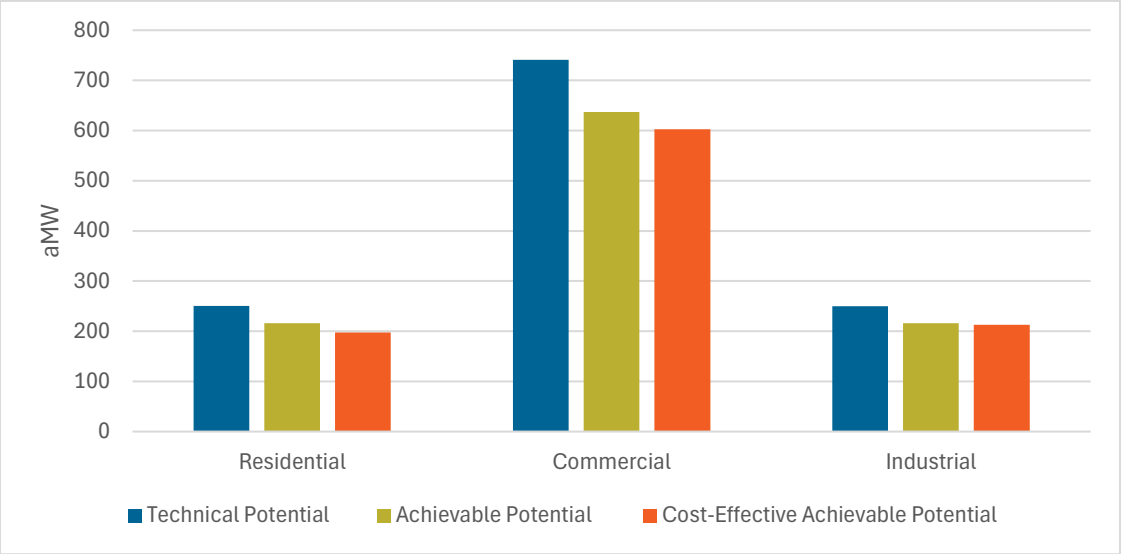
[1] OPUC 2024 Stat book – 10 Year Summary Tables: https://www.oregon.gov/puc/forms/Forms%20and%20Reports/2024-Oregon-Utility-Statistics-Book.pdf

experience, knowledge of current and developing markets, and future codes and standards. The first five years of this deployment are set in alignment with savings targets documented in Energy Trust's multiyear plan[2], which then influences and sets the market adoption rates deployed in the remainder of the savings projection horizon. Energy Trust's efficiency target for PGE in the next five years through 2030 is 166 average megawatts[3] (aMW). Taken together, this final 20-year savings projection is provided to PGE for inclusion in their Integrated Resource Planning (IRP) forecasts. The 2026 IRP results show that PGE can save 180 aMW in the next five years from 2026 to 2030 and over 754 aMW by 2045.[4] These results represent a 4% and 12% increase respectively in deployed cost-effective DSM potential over the prior IRP in 2025. The main drivers of this increased deployment are:

1. Growth in the PGE residential customer forecast and growth in the commercial and industrial load forecast.
2. Growth in avoided costs.
3. Updated measure assumptions and new measures.
4. Some increases in Energy Trust savings projections through 2030, which then set a higher starting point for replacement measure ramp rates and thus greater market penetration through the remainder of the projection.
5. New marginal line loss calculation methodology resulting in increased line losses and savings at the generator.

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



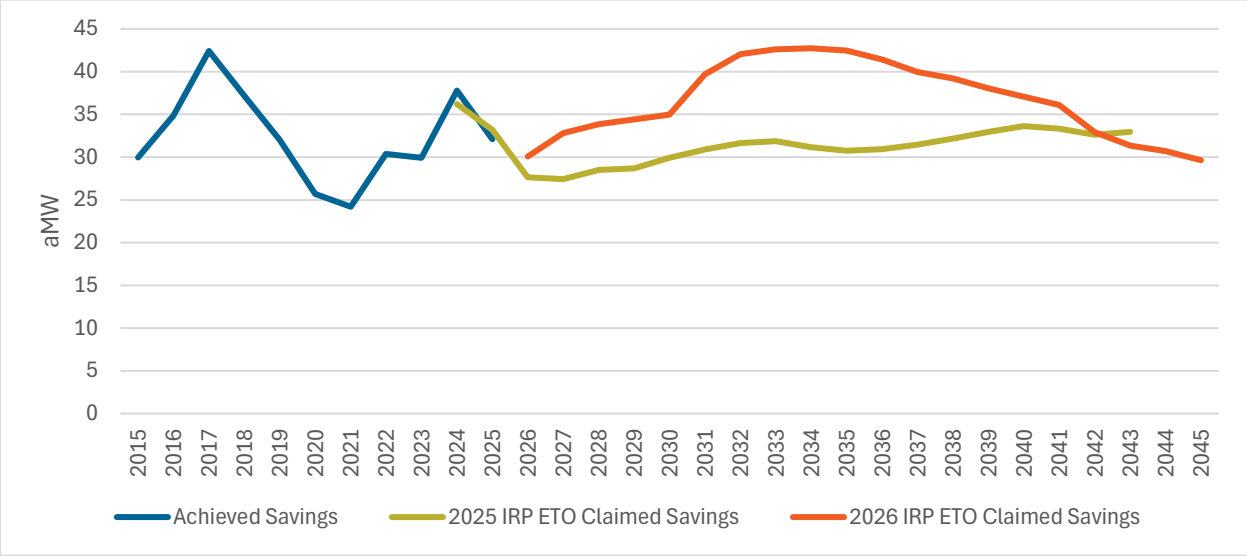
[2] See www.energytrust.org/wp-content/uploads/2025/12/Energy-Trust-2026-2030-Multiyear-Plan-with-financial-statements.pdf

[3] All energy described in this report is measured at the generator and efficiency savings are measured as first year savings.

[4] Includes 22.6 aMW of market transformation savings that Energy Trust will not claim resulting from residential and commercial lighting standards going into effect.

Figure 2 links actual historic savings going back to 2015 to the Energy Trust claimed savings projection for the 2026 IRP. It also compares the 2026 IRP forecast to the 2025 IRP forecast.

Figure 2 - Annual Savings Projection Comparison for 2025 and 2026 IRPs, with Actual savings since 2015

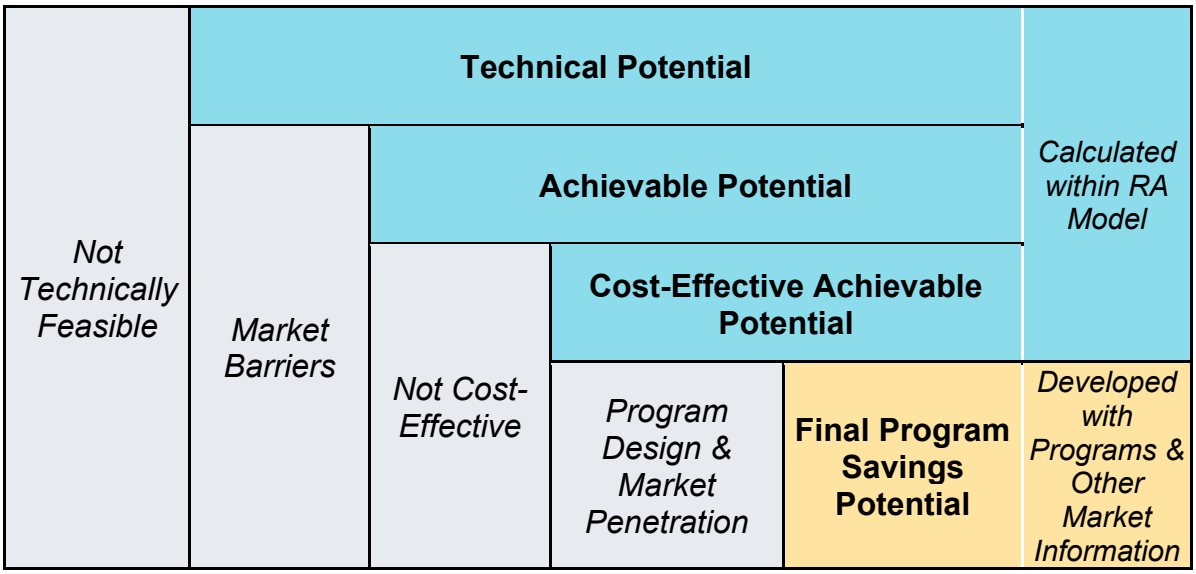


Energy Trust 20-Year Forecast Methodology

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



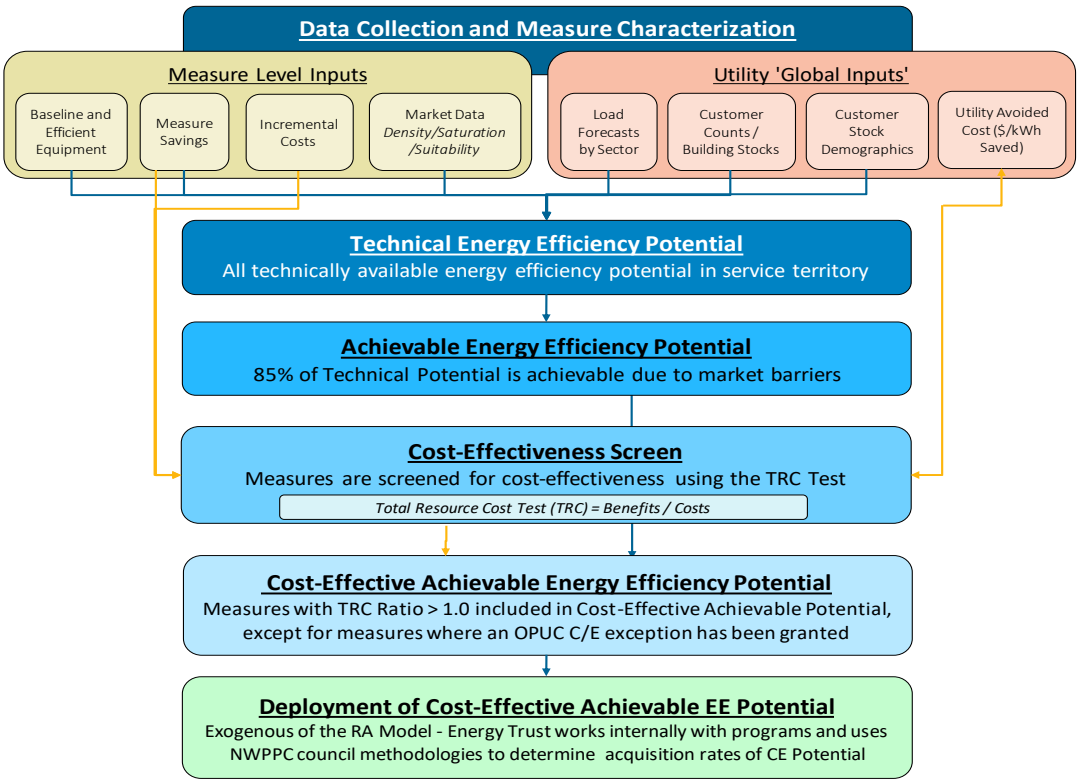
The RA Model utilizes the modeling platform Analytica®[5], an object-flow based modeling platform that is designed to visually show how different objects and parts of the model interrelate and flow throughout the modeling process. The model utilizes multidimensional tables and arrays to compute large, 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.

[5] http://www.lumina.com/why-analytica/what-is-analytica1/

Figure 4 - Energy Trust's 20-Year DSM Forecast Determination Flow Chart



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.[6] 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:***

[6] 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.

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[7], and engineering analysis. There are over 30 measure level inputs that feed into the model, but at 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 actually 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).

- ***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[8]****:* Avoided costs are the net present value of avoided energy purchases and avoided system costs that result from energy efficiency

[7] 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)

[8] Energy Trust uses a single blended avoided costs for its programs, measure development and benefit/cost metrics.

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 <u>not</u> 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 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[9].

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,
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.

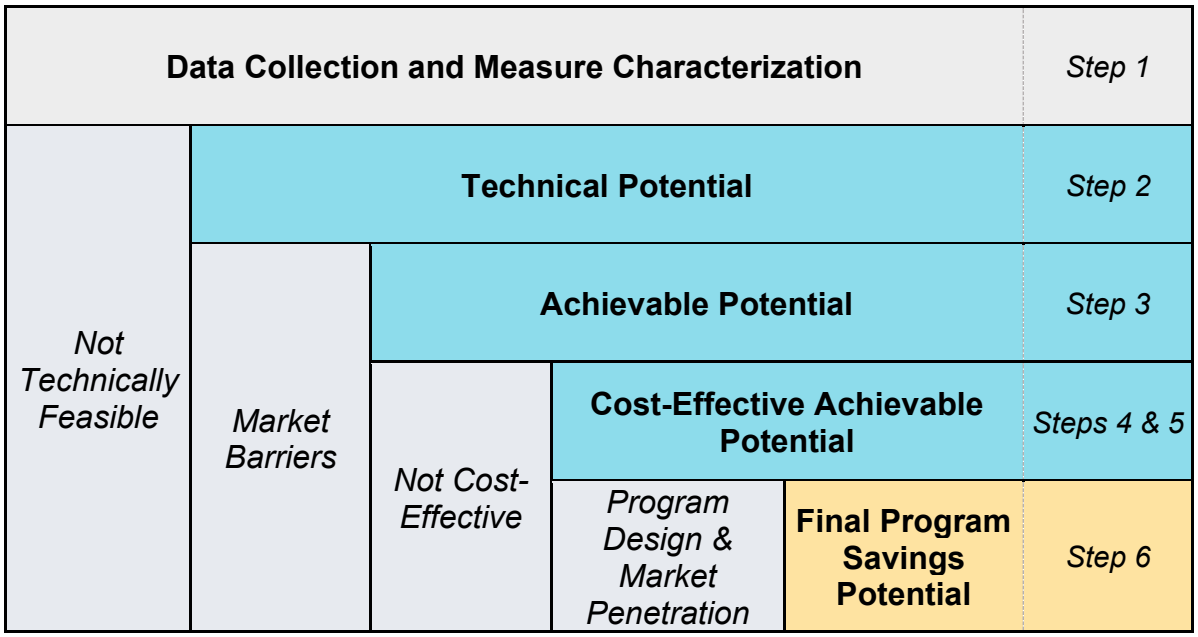
6. Deployment of Cost-Effective Achievable Energy Efficiency Potential

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, and 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.

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

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.

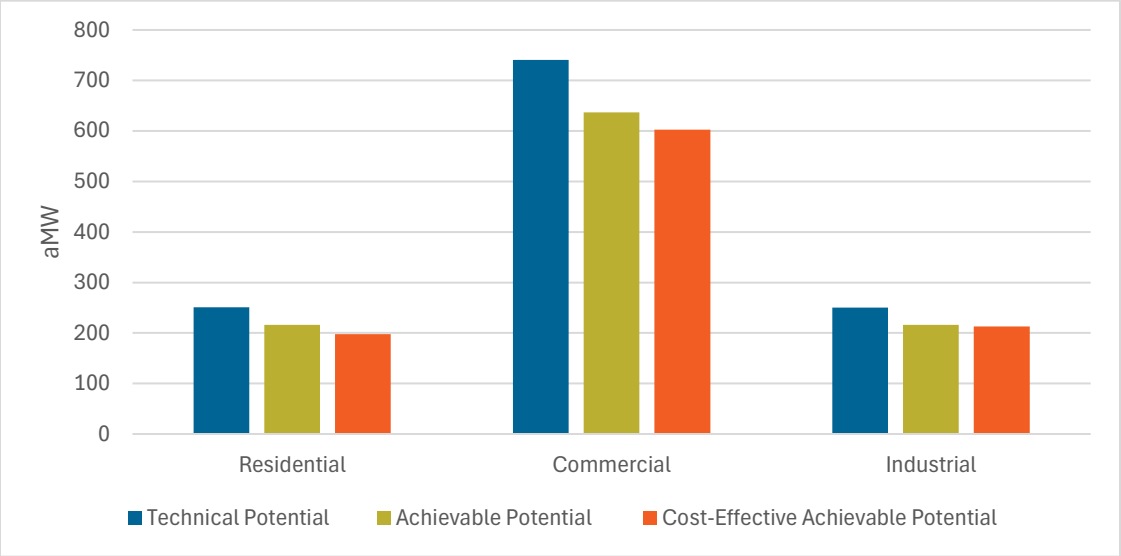
Table 1 - Summary of Cumulative Modeled Savings Potential - 2026–2045

Sector	Technical Potential (aMW)	Achievable Potential (aMW)	Cost-Effective Achievable Potential (aMW)
Residential	251	216	198
Commercial	741	637	603
Industrial	250	216	213
Total	**1,242**	**1,070**	**1,013**

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. 85% of the industrial technical potential is cost-effective, while the residential and commercial sectors cost-effective achievable potential are 79% and 81% of technical potential respectively.

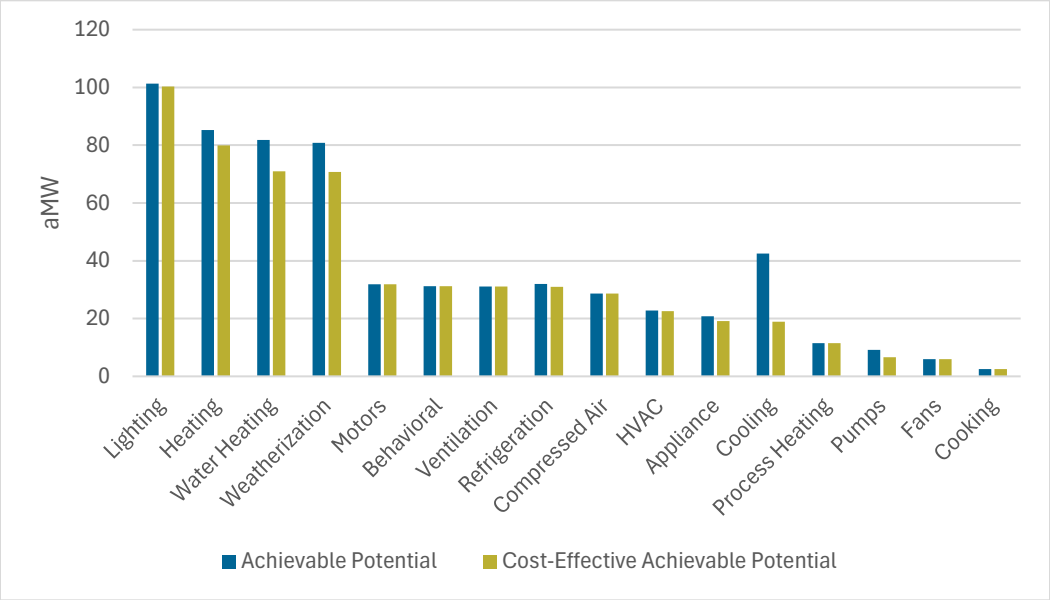
Figure 6 - Savings Potential by Sector – Cumulative 2026–2045



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, water heating and weatherization 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 pass the TRC test in the model.

Figure 7 – 20-year Cost-Effective Achievable Cumulative Potential by End Use



Contribution of Emerging Technologies

As mentioned earlier in this report, Energy Trust includes a suite of emerging technologies (ETs) in its model. The emerging technologies included in the model are listed in Table 2.

Table 2 - Emerging Technologies Included in the Model that are pertinent for PGE

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

Energy Trust recognizes that emerging technologies are inherently uncertain and utilizes a risk factor to hedge against that risk. The risk factor for each emerging technology is used to characterize the inherent uncertainty in the ability for ETs to produce reliable future savings. This risk factor was determined based on qualitative metrics of:

- Market risk
- Technical risk
- Data source risk

The framework for assigning the risk factor is shown in Table 3. Each ET was assessed within each risk category and a total weighted score was then calculated. Well-established and researched technologies

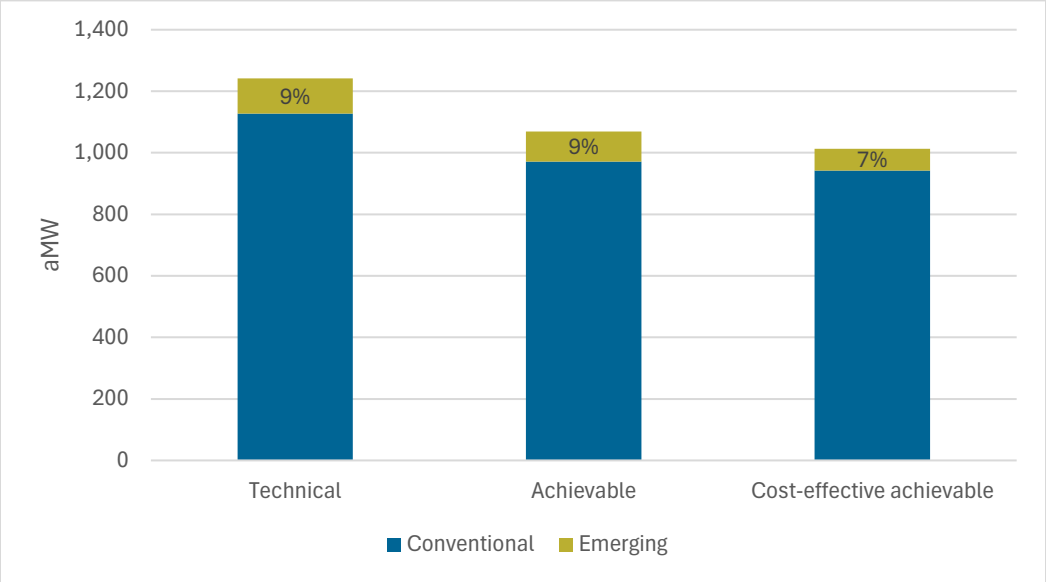
have lower risk factors while nascent, unevaluated technologies (e.g., CO2 heat pump water heaters) have higher risk factors. This risk factor was then used as a multiplier of the incremental savings potential of the measure.

Table 3 - Emerging Technology Risk Factor Score Card

	ET Risk Factor				
Risk Category	**10%**	**30%**	**50%**	**70%**	**90%**
Market Risk (25% weighting)	**High Risk:** • Requires new/changed business model • Start-up, or small manufacturer • Significant changes to infrastructure • Requires training of contractors. Consumer acceptance barriers exist.			**Low Risk:** • Trained contractors • Established business models • Already in U.S. Market • Manufacturer committed to commercialization	
Technical Risk (25% weighting)	**High Risk:** Prototype in first field tests. A single or unknown approach	Low volume manufacturer. Limited experience	New product with broad commercial appeal	Proven technology in different application or different region	**Low Risk:** Proven technology in target application. Multiple potentially viable approaches.
Data Source Risk (50% weighting)	**High Risk:** Based only on manufacturer claims	Manufacturer case studies	Engineering assessment or lab test	Third party case study (real world installation)	**Low Risk:** Evaluation results or multiple third party case studies

Figure 8 below shows the amount of emerging technology savings within each type of DSM cumulative potential. While emerging technologies make up about 9% of the technical potential, once the cost-effectiveness screen is applied, the relative share of emerging technologies drops to about 7% 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 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[10].

[10] 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 (2026-2045) 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	198	150	47
Commercial	603	603	0
Industrial	213	213	0
Total DSM:	**1,013**	**966**	**47**

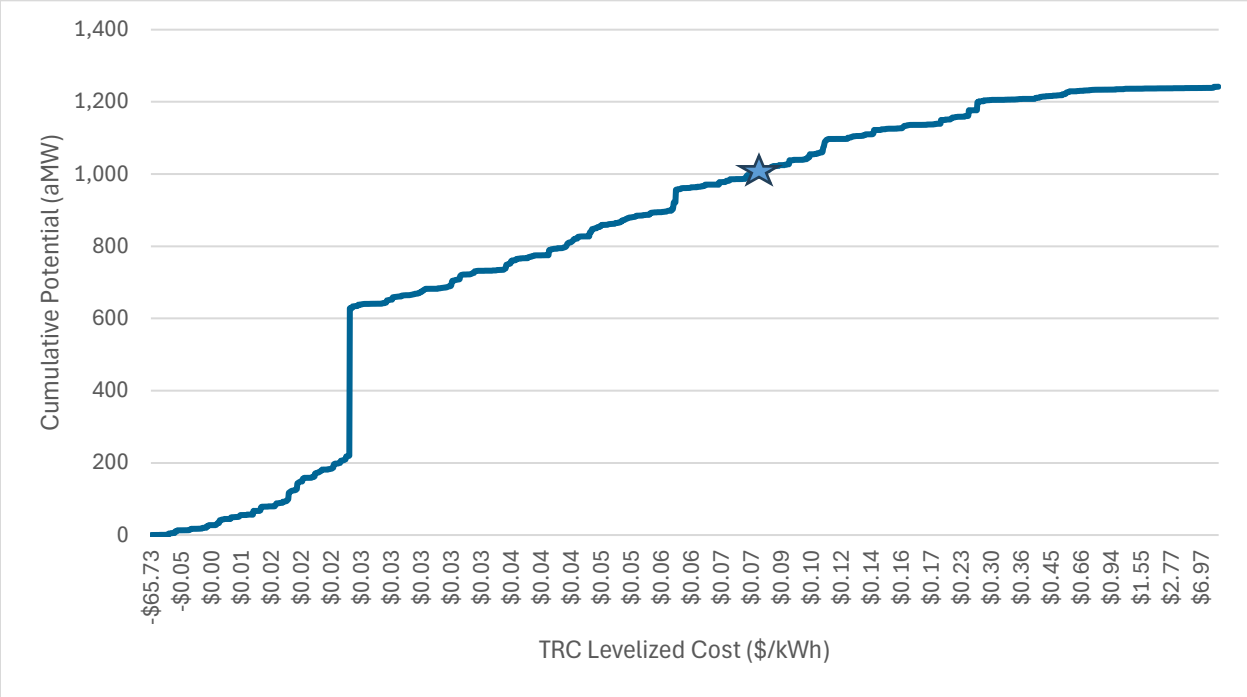
In this IRP, 5% of the cost-effective potential identified by the model is due to the use of the cost-effective override for measures. While lower than in the previous IRP (9%), this is still a higher share than in earlier IRPs and is attributable to the OPUC cost-effectiveness exception for manufactured homes early replacement (12 aMW of the 47 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 4% 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

Energy Trust published its multiyear plan[11] in 2025, and the strategies and savings targets documented in the plan established the starting point for and are consistent with the final savings projection shown below; Energy Trust's efficiency target for PGE in the next five years through 2030 is 166 aMW. The results of the final IRP savings projection show that PGE can save 180 aMW in the next five years from 2026 to 2030 and over 754 aMW by 2045[12]. This represents an 11.3 percent cumulative load reduction by 2045[13] and is an average of 0.8 percent incremental annual load reduction. The final savings projection is shown in Table 5 compared to the technical, achievable and cost-effective achievable potential.

Table 5 - 20-Year savings potential by type, including final savings projection (aMW)

Sector	Technical Potential	Achievable Potential	Cost-Effective Achievable Potential	Final Savings Projection
Residential	251	216	198	173

[11] See www.energytrust.org/wp-content/uploads/2025/12/Energy-Trust-2026-2030-Multiyear-Plan-with-financial-statements.pdf

[12] 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 20.8 aMW of the combined commercial and industrial final savings projections and 1.8 aMW of the residential final savings projection.

[13] 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. The only exception to this is home energy reports which are treated as non-cumulative with a one-year measure life.

Commercial	741	637	603	268
Industrial	250	216	213	223
Exogenous Savings[14]				90
Total	**1,242**	**1,070**	**1,013**	**755**

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).

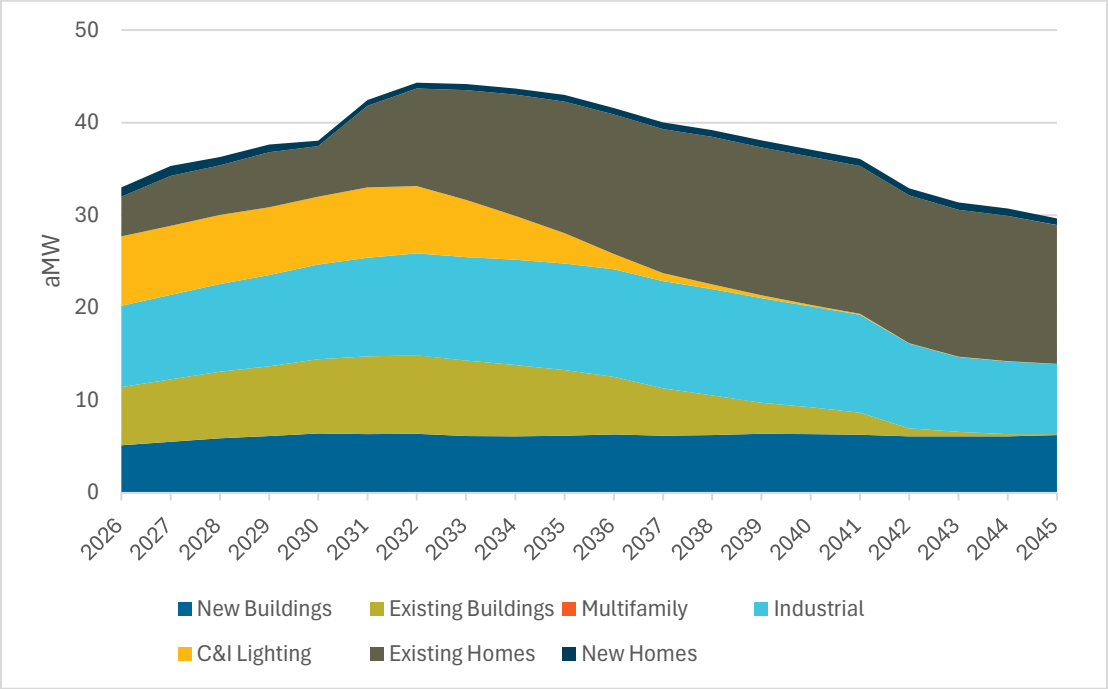
Exogenous savings are calculated outside of the RA model because they are generally accounted for in market characterization assumptions (prior codes), their baseline is present in the utility load forecast (residential electrification), or the savings are a different category than modeled potential (home energy reports). Energy Trust models prior codes using a forecast from NEEA. Residential electrification was calculated as incremental lost opportunity savings above PGE's electrification forecast and were

[14] Exogenous savings are calculated outside of the RA model and consist of commercial and residential prior codes, industrial large projects, residential home energy reports and residential electrification.

deployed consistent with similar lost opportunity measure adoption. Finally, Energy Trust and PGE have begun to offer Home Energy Reports which have been exogenously added due to their ability to be re-installed and are non-cumulative, one year savings. In total exogenous savings total 90 aMW and make up 12% of the final savings projection.

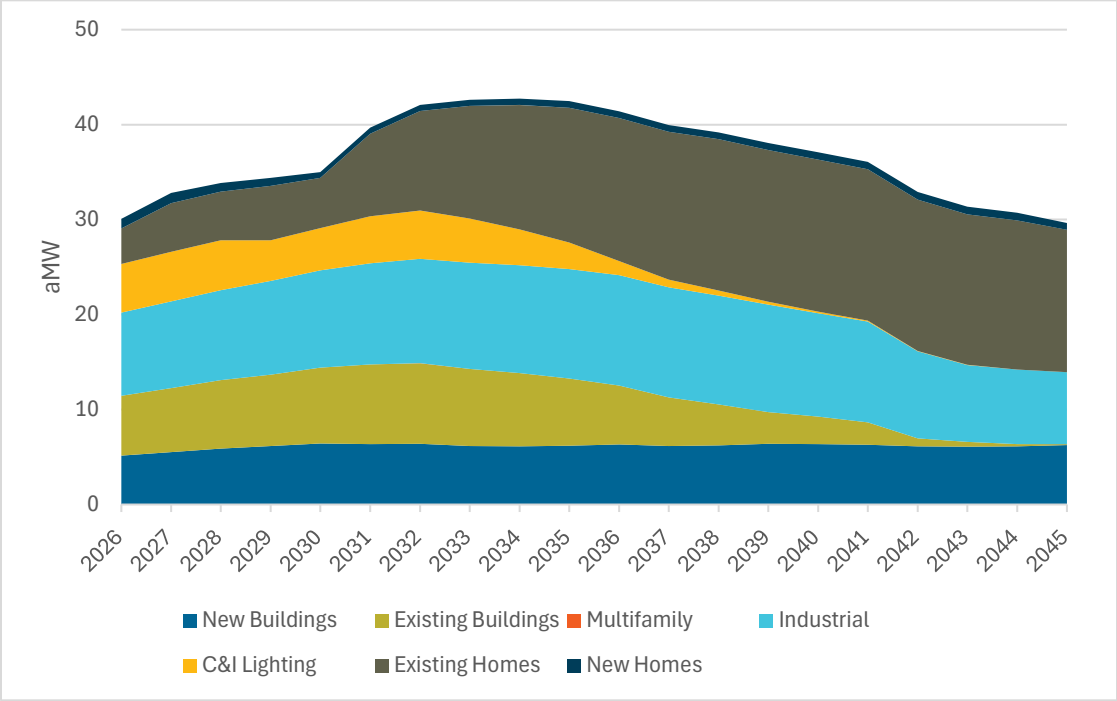
The final savings projection of 755 aMW in Table 5 represents 20 years of efficiency savings. The annual shape of the deployed efficiency forecast is shown in Figure 10 below.

Figure 10 – Annual Deployed Final Savings Potential



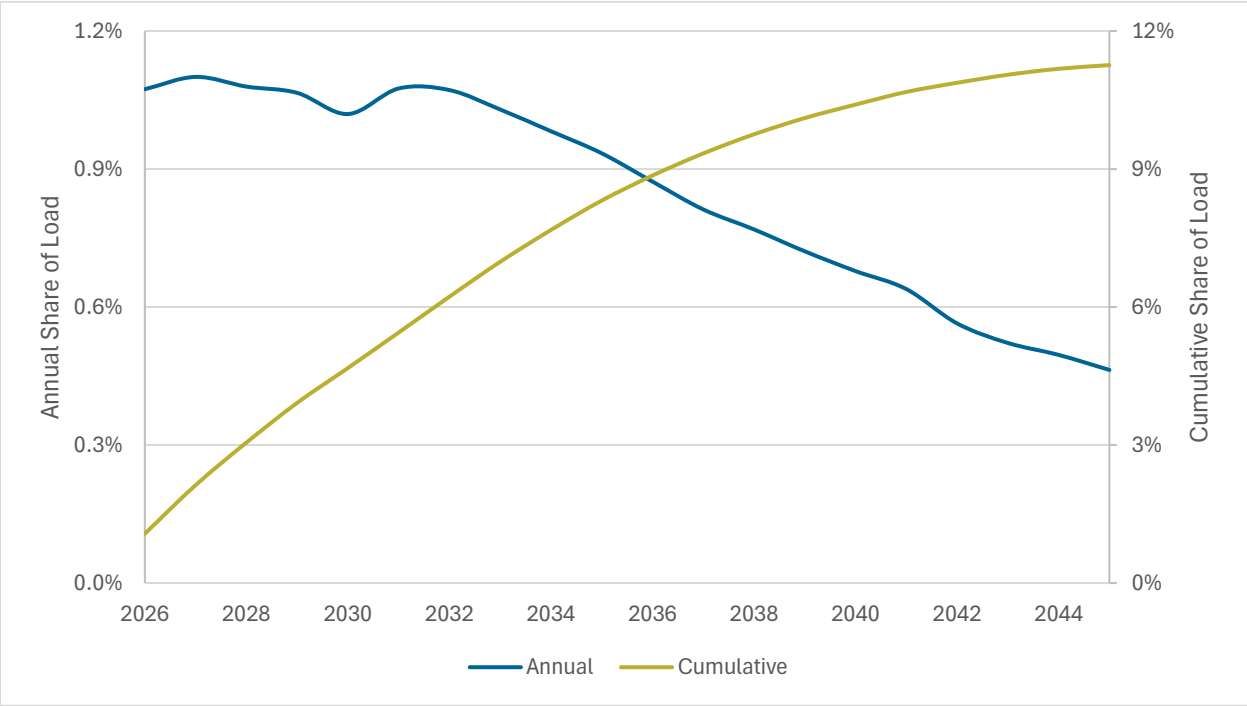
As previously noted, the final savings projection depicted in Figure 10 above includes 22.6 aMW of market transformation lighting savings that energy trust will not claim. Figure 11 below shows the annual efficiency forecast of Energy Trust claimed savings.

Figure 11 – Annual Deployed Energy Trust Claimed Savings Potential



Finally, Figure 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 0.5% at its lowest to 1.1% 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 11.3% by 2045, 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[15].

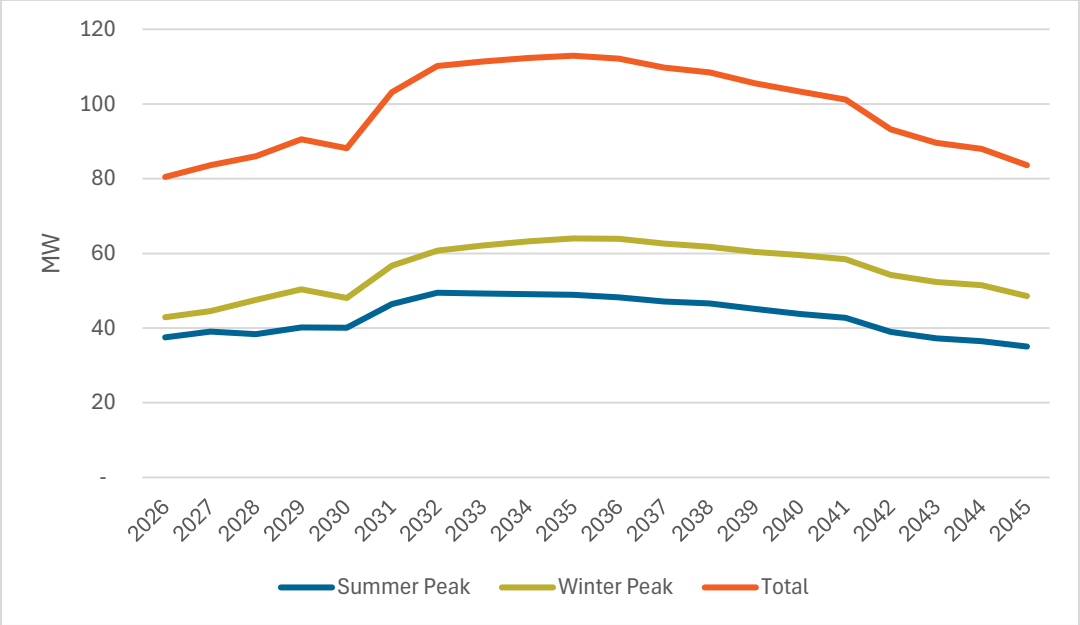
Peak hour factors are the percentage of annual energy savings that occur during peak hours over the course of a year. Energy Trust calculates peak demand factors using Equation 1, where load factors and coincidence factors being derived from the NWPCC library of load profiles.

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 projection based upon the results of the 20-year forecast. Each measure analyzed is assigned a load shape and the appropriate peak factor is applied to the annual savings to calculate the overall DSM contribution to peak day capacity. Cumulatively, this is equal to 1,973 MW[16], as shown in Table 6 below.

Figure 11 - Annual Deployed Peak Savings Contribution by Season



[15] For the 2025 version of this report see Appendix 9 of Energy Trust's "*2025 Annual Report to the Oregon Public Utility Commission & Energy Trust Board of Directors*" available at www.energytrust.org/wp-content/uploads/2026/04/Energy-Trust_2025-Annual-Report.pdf

[16] Peak results do not include energy savings from exogenous categories.

Table 6 - Cumulative Deployed Peak Savings Contribution by Sector

Sector	Cumulative Peak Savings (MW)	% of Overall Peak Savings
Residential	751	38%
Commercial	701	36%
Industrial	521	26%
Total	**1,973**	

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 potential submitted by Energy Trust are shown below in Table 7. For the 2026 IRP analysis, these savings total 72.3 aMW at a weighted average levelized cost[17] of $0.431/kWh.

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

Sector	Non-Cost-Effective Achievable Potential (aMW)[18]	Weighted Average Levelized Cost ($/kWh)
Residential	30.0	$0.455
Commercial	39.3	$0.430
Industrial	3.0	$0.196
Total	**72.3**	**$0.431**

[17] This levelized cost represents the total resource cost net of non-energy benefits, levelized over measure life ($/kWh) plus a 37% administrative cost adder.

[18] The values in this column do not exactly match the difference between Achievable Potential and Cost-Effective Achievable Potential in Table 5 for a number of reasons including substitution between competing measures, cost-effective override, and the timing of discretionary measures on the margin of cost-effectiveness.

Appendix Q Sylvan Energy Analytics Flexibility Study

PGE 2026 IRP Flexibility Study

Prepared for:

Portland General Electric

Prepared by:

SYLVAN ENERGY ANALYTICS

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1. Background

For the 2026 Integrated Resource Plan (IRP), Portland General Electric (PGE) engaged Sylvan Energy Analytics (Sylvan) to perform the Flexibility Study, a component of PGE's IRP analysis. This study builds off the 2019 and 2023 IRP flexibility studies, conducted by Blue Marble Analytics (Blue Marble transitioned its services to Sylvan in 2024). The analysis utilizes the GridPath production-cost modeling platform to evaluate PGE system operations across day-ahead, hour-ahead, and real-time commitment stages. The flexibility study conducted for the IRP refers to three individual studies: flexibility adequacy, flexibility integration cost of new resources, and new storage resource (e.g., batteries) flexibility value.

Sylvan Energy Analytics is a Portland-based energy consulting and software development firm specializing in power system modeling, integrated resource planning, and resource adequacy. Sylvan conducted the flexibility analysis using GridPath, a comprehensive power-system-modeling platform it develops and maintains.

GridPath is an open-source platform, designed as a modular and highly customizable power-system-planning software tool. GridPath integrates production-cost simulation, used here for the Flexibility Study analysis, in addition to capacity-expansion, asset-valuation, and resource adequacy modeling functionality within the same platform. GridPath's complete codebase is publicly accessible for download, review, and modification on GitHub at https://github.com/blue-marble/gridpath and extensive documentation is available on Read the Docs at https://gridpath.readthedocs.io/en/latest/.

2. Modeling Methodology

Introduction

Maintaining reliability is a primary goal for power systems. The system's ability to respond to uncertainty in loads and generation, known as flexibility, is part of maintaining reliability.[1,2] Greater quantities of variable energy resources influence the flexibility of a system, changing the likelihood, magnitude, and timing of generation uncertainty. As Portland General Electric (PGE) plans for continued decarbonization of its generation portfolio, the integration of greater quantities of renewables affects the flexibility of the system. This study analyzes the flexibility of a proxy PGE future system and quantifies the need for flexible resources, the operational costs of integrating increasingly more variable resources, and the value of storage resources that can respond quickly to fluctuations and forecast error.

Flexibility Study Framework

The Flexibility Study serves as one component of PGE's holistic IRP resource valuation framework. It consists of three distinct components, each addressing a specific aspect of flexibility-related system dynamics, including reliability and economics.

The first component is the Flexibility Adequacy Analysis. The primary objective of the Flexibility Adequacy Analysis is to assess whether the resource portfolio has sufficient short-term flexibility to maintain load-resource balance, i.e., whether the portfolio of resources can respond to rapid changes in net load as well as forecast error.

The second component is the Flexibility Value Analysis. This component of the Flexibility Study quantifies the operational benefits provided by fast-responding assets, specifically energy storage. This analysis seeks to quantify the avoided operational costs and other economic benefits associated with a resource's ability to ramp quickly and/or to mitigate forecast errors in load and variable generation.

The third component of the Flexibility Study is the Integration Cost Analysis. This component investigates the incremental operational impacts of incorporating variable energy resources (VERs), such as wind and solar. Because these resources are variable and uncertain, they can increase the flexibility requirements of the existing system. The Integration Cost Analysis evaluates the resulting increase in operational costs, which may include increased fuel

[1] National Renewable Energy Laboratory. Advancing System Flexibility for High Penetration Renewable Integration. 2015. https://docs.nrel.gov/docs/fy16osti/64864.pdf
[2] Flexibility does not refer to flexible loads associated to large load growth.

consumption, variable O&M costs, and start-up costs for the thermal fleet as well as less optimal market transactions.

Production Cost Model

The Flexibility Study methodology utilizes a high-fidelity, operationally realistic simulation of the PGE system under typical grid conditions. The analysis employs a multi-stage commitment and dispatch modeling approach whose goal is to capture the impacts of both forecast error and the physical constraints of the generating fleet (e.g., ramp rates, minimum up/down times, and start-up costs).

For this Flexibility Study, GridPath is configured as a multi-stage optimal commitment and dispatch model. We use GridPath to optimize generator dispatch and system operation for two future years of interest: 2030 and 2035. One year of analysis consists of 52 one-week model runs. For each one-week period, the model is run in three stages: day-ahead (DA) with an hourly timestep, hour-ahead (HA) with a 15-minute timestep, and real-time (RT) with a 15-minute timestep. GridPath creates a constrained optimization with an objective function of minimizing total system operating costs subject to a set of system- and generator-level operational constraints. The model takes in inputs at each stage and optimizes system dispatch subject to the operational constraints relevant at that stage and decisions that were made in the previous stages, including generator commitment and market transaction decisions. Detailed generator operational constraints include minimum loading levels, minimum up- and down-times, ramp rate limits, etc. In addition, the model enforces system-level market availability constraints and reserve requirements.

Input Data

The Flexibility Study is designed to investigate "typical" system operations under median conditions. This approach allows for the derivation of representative operational costs and resource values. While extreme grid conditions and resource adequacy (RA) stress are critical to system planning, those elements are addressed via other components of the PGE IRP valuation framework, such as the Sequoia model, PGE's resource adequacy assessment tool.

To maintain alignment across the different 2026 IRP workstreams, the flexibility analysis utilizes PGE's Reference Case economic assumptions. This includes Reference forecasts for natural gas prices, market electricity prices, and carbon pricing.

The analysis uses PGE's September 2025 corporate load forecast for a median (p50) year, reflecting expected electricity demand under average weather conditions.[3] The PGE system is modeled with access to an external market and market availability limits are set to p50 resource adequacy assumptions, as represented in Sequoia.

The simulated portfolio includes PGE's existing fleet of generating assets and long-term contracts. Because the existing portfolio of generating assets and contracts may not meet all forecasted demand in 2030 and 2035, the model employs two distinct methodologies to fill the resource adequacy gap, depending on the specific study objective.

In the Flexibility Adequacy Analysis, an expensive day-ahead (DA) on-peak capacity product is available to the system to meet resource adequacy. The goal is to establish a starting flexibility "need" for the evolving system, i.e., a minimum amount of flexible capacity that may need to be added to the system. The DA on-peak capacity product is available in 100 MW increments for the 16-hour on-peak block. If selected in the DA, the DA on-peak capacity product is also available in the HA and RT stages, but it cannot be decommitted. The use of an inflexible resource allows the model to identify baseline flexibility deficits that would occur if no additional flexible resources were added to the system.

In the Flexibility Value Analysis and Integration Cost Analysis, future resource adequacy shortages are met using a proxy resource portfolio rather than an inflexible DA capacity block product. In these studies, the goal is to develop a realistic system to determine a representative estimate of the flexibility value and integration costs of new resources as the system evolves. By utilizing a diverse and plausible future resource mix, the approach ensures that the calculated flexibility value of a new asset such as a standalone battery or the integration cost of a new VER project is based on a realistic representation of the future grid that is first deemed resource adequate. A summary of relevant input data for the 2026 IRP Flexibility Study analysis is described in Table 1 below.

[3] Sylvan Energy Analytics was contracted to conduct this study prior to the completion of PGE's May 2026 corporate load forecast. The newer load forecast is not expected to have a material impact on these results.

Table 1. Flexibility Study Data Inputs

Data Input	Flexibility Adequacy	Flexibility Values and Integration Costs
Test Years	2030, 2035	←
Gas Prices	Reference	←
Carbon Prices	Reference	←
Electricity Prices	Reference	←
Load Forecast	p50 of Reference for each test year	←
VER generation	Profiles for one representative year of historical wind and solar data	←
Existing Base Portfolio of Owned and Contracted Resources	Reference	←
Market Availability	Aligned with p50 resource adequacy Assumptions	←
Reserves	Regulation, spin, and load-following	←
Capacity Additions / Availability	Day-ahead, high load hour (HLH) block capacity that is more expensive than existing system generation & markets, and provides no flexibility	Proxy resource additions: Representative resources broadly aligned with the Final Shortlist of the 2025 RFP (added for 2030, see Table 2) and draft additions from a ROSE-E portfolio to meet adequacy for reliability only (added for 2035, see Table 3)

Portfolio Effects

An important consideration in designing modeling approaches and interpreting results from the Flexibility Study is that the net value of any single asset is not a static attribute. Rather, these values are dynamic variables determined by the overall portfolio composition, including the existing resource mix and the specific proxy resources used to meet capacity adequacy requirements. This phenomenon is known as portfolio effects.

As the simulated portfolio evolves, the marginal economic and operational impact of adding a specific technology also changes based on the synergy or competition between resources in the portfolio mix. As the penetration of a specific technology increases, the marginal value of additional units typically declines. For example, in a system with high battery storage capacity, the incremental flexibility value of adding another battery may decrease as the system's flexibility requirements are already met. Wind or solar generation increase system-

wide variability and uncertainty, so the cost to integrate an additional similar project is higher in a portfolio with already-high penetrations of those technologies. Portfolio effects can also be positive. For example, the addition of energy storage can lower the integration costs of solar energy by absorbing mid-day oversupply and discharging it during the evening ramp, thereby making additional solar easier to integrate into the grid. Because of these dynamics, the flexibility values and integration costs should not be viewed as constants; they are snapshots of a specific resource trajectory. Changes in the underlying IRP portfolio assumptions may alter the flexibility economics of the individual technologies.

As described above, a diverse mix of proxy assets was added to the Flexibility Value and Integration Cost simulations to eliminate capacity-related unserved energy. The additions to the 2030 simulation are broadly consistent with the Final Shortlist of the 2025 RFP (Table 2); the additions to the 2035 simulation are based on draft VER, battery, and capacity additions from a ROSE-E portfolio that meets reliability goals only (Table 3). The 2035 additions are instead of, not in addition to the 2030 RFP proxy resources. These additions ensure resource adequacy is met with a representative portfolio where no single technology disproportionately influences the flexibility value or integration cost results due to the portfolio effects discussed above.

Table 2. Resource Adequacy Additions to 2030 Portfolio

2030 Resource Addition	Capacity (MW)
Solar East Hybrid (1:1)	600[4]
Solar East	100
Washington Wind	663
Term Natural Gas Energy	196

Table 3. Resource Adequacy Additions to 2035 Portfolio

2035 Resource Addition	Capacity (MW)
Solar West	224
Solar East	894
Montana Wind	1224
Washington Wind	1224
Batteries	2800
Term Natural Gas Energy	450

[4] Represents 600 MW of solar and 600 MW of storage.

3. Flexibility Adequacy Analysis

Modeling Approach

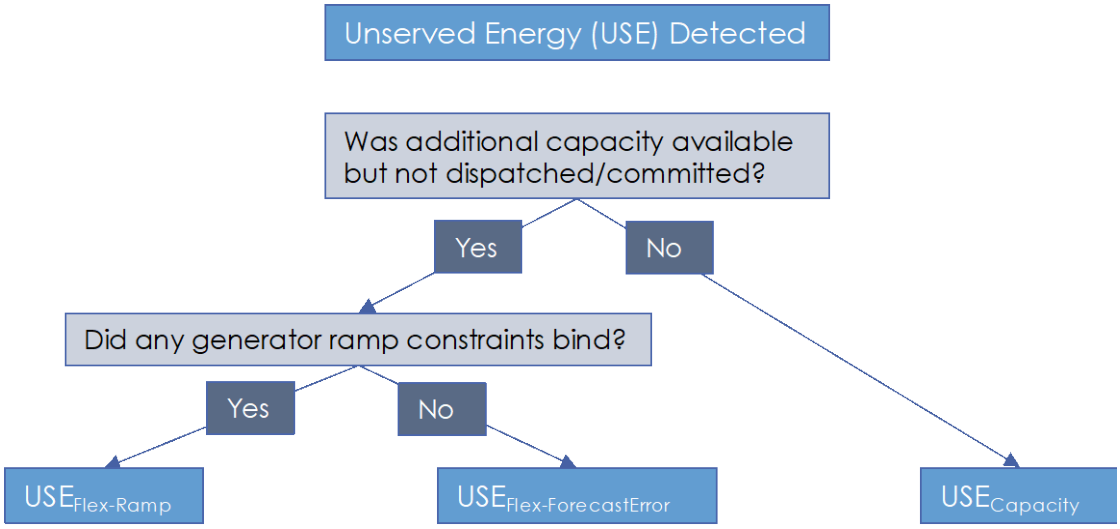
The Flexibility Adequacy Analysis focuses on upward flexibility challenges. While several metrics from production cost simulation exist that could indicate insufficient flexibility – for example, unserved energy or reserve shortfalls – it is important to distinguish between reliability events that can be attributed to insufficient flexibility and those due to inadequate capacity. Consistent with the analysis first developed in the 2019 IRP Flexibility Study, we use unserved energy due to flexibility shortages (USE_{Flex}) as the main metric indicating flexibility challenges. This metric was adapted from The Flexibility Metrics and Standards Project -- a California Energy Systems for the 21st Century (CES-21) Project.[5] As employed here, USE_{Flex} is not a metric of "expectation" or "probability," but rather an accounting of the frequency and magnitude of these events in a single "median" future year for load, renewable resource output, and hydro conditions.

Unserved energy is the main way in which problems due to upward flexibility challenges – either large ramps or forecast error – manifest themselves. To decide whether the observed violations are due to insufficient flexibility or to inadequate capacity, we adapt the method used in CES-21. Whenever we observe unserved energy, we follow the decision process described in Figure 1.

The first decision point is to determine whether capacity is available on the system that is not committed and/or dispatched. If all available capacity was running, we ascribe the reliability event to insufficient capacity and add the shortage to $USE_{Capacity}$, the unserved energy attributable to resource inadequacy, not flexibility inadequacy. If additional capacity is available during the time with unserved energy but is not running, we attribute the unserved energy to insufficient flexibility and further divide these events into two flexibility types. As described above in the section discussing Input Data, $USE_{Capacity}$ observations are filled with an inflexible DA block product. The second decision point allows us to understand whether the flexibility event is caused by insufficient ramping capability or by forecast error. In the former case, capacity is available and running, but output cannot be adjusted fast enough to follow net load, manifesting itself as a binding ramp constraint; in the latter case, there are no binding ramp constraints and the reliability event occurs because of a difference between the net load forecast (usually in the day-ahead commitment stage) and the realized net load that the system is not able to adjust to, e.g., because of under-commitment of resources.

[5] Astrape Consulting, EPRI, LLNL, PG&E, and SDG&E, "Flexibility Metrics and Standards Project -- a California Energy Systems for the 21st Century (CES-21) Project," 06-Jan-2016.

Figure 1. Decision Tree for Determining USE Type



Results and Discussion

The results from the Flexibility Adequacy Analysis are presented in Table 4 below. The analysis indicates that the modeled PGE system, as configured for this study's test years, has a high degree of operational flexibility. In the 2030 system, few flexibility-related unserved energy events occur: a total of 10 MWh of USE_{Flex} in nine 15-minute segments and a maximum observed shortage of 13 MW. By 2035, increases in load and the associated load forecast error result in USE_{Flex} of 22 MWh spread over nine 15-minute segments, with a maximum shortage of 25 MW.

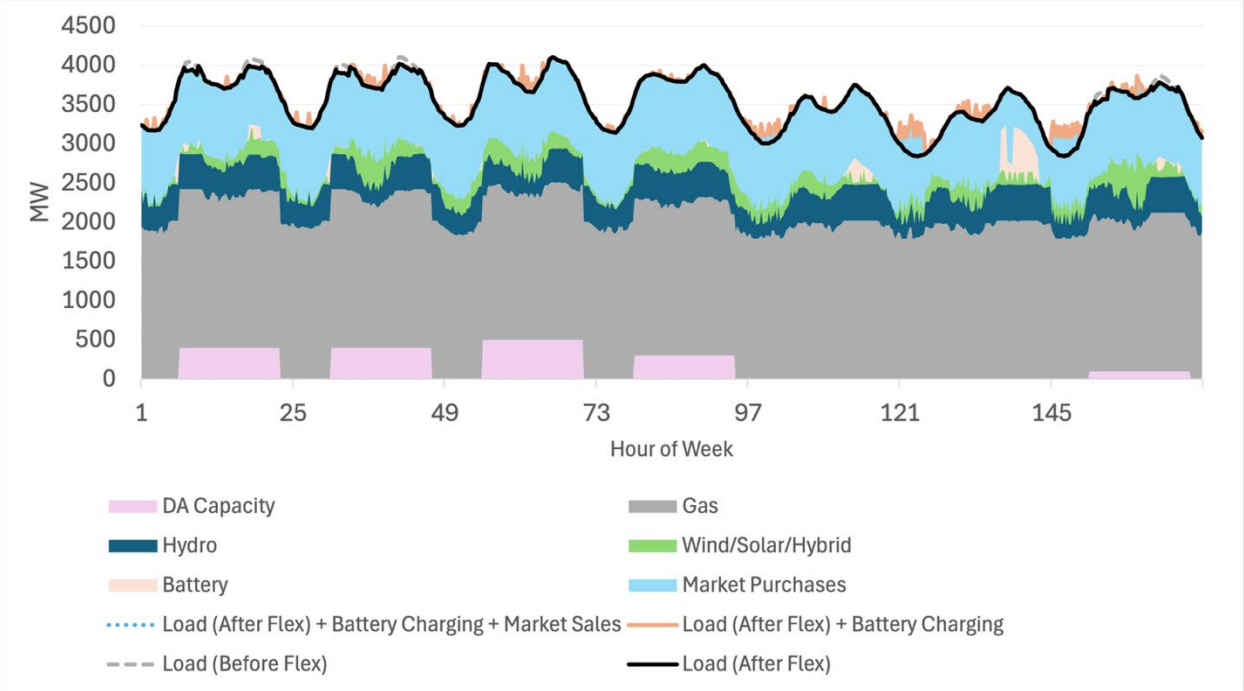
Table 4. Real Time USE_{Flex} in 2030 and 2035

	2030	2035
# 15-min Timepoints	9	9
% Timepoints	0%	0%
Total MWh	10	22
Max MW	13	25

As discussed in the Input Data subsection above, the Flexibility Adequacy Analysis uses an expensive DA capacity product to meet future resource adequacy while providing no flexibility to the system, with the goal of establishing a baseline need for flexible resources. Figure 2 shows the system's real time dispatch in a 2030 week in winter to demonstrate the

highest utilization of the DA product, with up to 500 MW used to fill any resource adequacy gap.

Figure 2. Real Time System Dispatch, December Week, 2030



Replacing the inflexible DA capacity product with the diverse proxy portfolio resource additions described in Tables 2 and 3 results in the elimination of all flexibility adequacy events in both 2030 and 2035, suggesting that, while a baseline flexibility need exists, under representative resource development scenarios, PGE's system is flexibility adequate.

The results of the 2026 Flexibility Adequacy Study indicate that under the modeled resource trajectories and operational practices, the PGE system can meet short-term balancing requirements. A central finding of the Flexibility Adequacy Analysis across recent IRP cycles has been the critical role of forecast error as a primary flexibility challenge. Refining the treatment of forecast error reserves, alongside careful of consideration of the role and capabilities of storage resources and renewable curtailment within operational modeling, would ensure that planning simulations accurately reflect the operational practices, balancing heuristics and procedures, and flexibility requirements of the PGE grid.

4. Flexibility Value Analysis

Modeling Approach

The goal of the Flexibility Value Analysis is to account for the flexibility provided by various resource options within PGE's portfolio development framework. Consistent with previous IRP cycles, the 2026 IRP estimates flexibility value, a component of PGE's economic analysis that captures the value of providing flexibility to the system by responding to forecast errors, enabling fast ramping, and meeting reserve requirements.

Flexibility values of new resources are estimated using GridPath production cost simulations of the PGE system. As described in the Input Data and Portfolio Effects sections, this analysis includes the year specific representative future resource portfolio to ensure Resource Adequacy detailed in Tables 2 and 3, as flexibility values are a function of interactive portfolio effects. For each resource option, the values presented here are calculated by simulating the system with and without the new resources and then comparing the operational costs of the two scenarios. The resources tested are 100 MW batteries with durations of 4, 6, and 8 hours and round-trip efficiency of 85 percent, a 10-hour pumped hydro storage resource with round-trip efficiency of 81 percent, and a 100-hour multi-day storage (MDS) technology with round-trip efficiency of 35 percent.

Results and Discussion

Estimates of flexibility values for new storage resources based on the 2030 and 2035 test years are summarized in Table 5. These values are dependent on the system that the resources are added to. The marginal value of each resource will decrease as more of it is added to the system and, beyond declining marginal benefits, the value of each resource is dependent on the resource mix of the system we are adding to. The values in Table 5 represent "mid" estimates with Reference assumptions and with the resource adequacy shortage filled with a diverse resource portfolio in the future years.

Table 5. Flexibility Value of Storage Resources (2026$/kW-year)

	2030	2035
4-Hour Battery	$9.8	$2.2
6-Hour Battery	$12.5	$4.0
8-Hour Battery	$14.9	$5.9
10-Hour Pumped Storage	$17.0	$8.7
100-Hour Multi-Day Storage	$5.8	$6.9

The results reflect the previously discussed portfolio effects, where the marginal value of an asset is intrinsically linked to the existing resource mix.

Compared to the 2023 IRP, the 4-hour and 6-hour battery flexibility values are lower in the 2030 and 2035 test years. This is a consequence of the significant volume of 4-hour battery and hybrid resources added to the PGE reference baseline portfolio for the 2026 IRP (about 700 MW) relative to the 2023 IRP. By 2035, an additional 2800 MW of 4-hour batteries are added to the system for resource adequacy. As the system becomes saturated with short-duration resources, the incremental flexibility value of adding more 4-hour batteries begins to decline. Longer-duration technologies retain a higher portion of their flexibility value. These assets provide sustained ramping and balancing capabilities that provide additional value, even as the penetration of shorter-duration batteries increases.

We also test a 100-hour MDS technology. Given its low round-trip efficiency (35%), the value of MDS is expected to manifest in longer-term seasonal balancing and resource adequacy value streams, captured in other segments of the IRP valuation framework, rather than the short-term balancing examined in this flexibility analysis. By 2035, the modeled system is assumed to be heavily saturated with 4-hour batteries that are effective at managing intra-day flexibility requirements; the remaining system stresses shift toward longer time horizons within the week, allowing MDS to retain and even gain value, as multi-day energy shifting needs increase. Whether MDS will contribute toward within-the-week balancing requirements will depend on its incentive structure as well as any costs not modeled here such as degradation due to frequent cycling.

5. Integration Cost Analysis

Modeling Approach

Since 2009, PGE has quantified the costs associated with integrating wind and solar generation into its power system. The 2026 IRP continues this practice using multi-stage commitment and dispatch modeling to capture the short-term operational adjustments required to balance variable energy resources. We use GridPath to simulate the variable costs associated with meeting load over the course of a "median" year, including fuel costs, variable operations and maintenance costs, startup costs, and costs and revenues associated with market interactions.

One challenge in estimating integration costs is distinguishing between the energy value of a resource (based on when it produces electricity) and its integration cost (based on its variability and uncertainty). To isolate the integration cost, we compare a case with 100 MWa of each of the test resources to one in which we add a flat block resource that matches the weekly capacity factor of the test resource. The system cost delta between these two runs is divided by the total resource output. This identifies the cost impact specifically attributable to short-term fluctuations and forecast errors, independent of seasonal availability.

High production from renewable resources can result in periods of time where the system has an oversupply of renewable energy, which may be curtailed. Curtailment may occur for economic or operational reasons, and the cost and amount of curtailment depends on a variety of factors including market prices, system conditions, and resource constraints. Within the Integration Cost Analysis simulation, curtailment of renewable resources is allowed at no cost, providing flexibility value to the system. If renewable resources were not allowed to curtail or if curtailment incurred a cost (e.g., for resources that must forego the production tax credit to curtail), we would expect the renewable integration costs to be higher than those listed in Table 6 below.

Results and Discussion

The estimated integration costs for 100 MWa of various solar and wind resources are summarized in Table 6. These costs represent the operational cost for variability and uncertainty in 2026 dollars per megawatt-hour of each resource.

Table 6. Integration Cost of Resource Options (2026$/MWh)

	2030	2035
Solar East	$7.1	$5.5
Solar West	$5.5	$3.1
Montana Wind	$1.0	$5.1
Washington Wind	$3.8	$5.3

For the 2026 IRP, we estimate renewable integration costs for 100 MWa of wind and solar resources based for the 2030 and 2035 test years. Because of portfolio effect, these values are dependent on the portfolio mix assumed for each test year.

For example, the difference between Montana and Washington wind integration costs in 2030 highlights the value of geographic diversity. The 2030 portfolio contains Washington wind only and no Montana wind, so the integration cost of an increment of Montana wind has a substantially lower integration cost that Washington wind in 2030. By 2035, a significant amount (1200 MW) of Montana wind is added to the modeled portfolio, so additional Montana wind becomes more expensive to integrate. The increase in integration costs for both the Washington and Montana resources is primarily driven by the saturation effect associated with higher penetrations of wind generation. As the volume of these specific resources increases in the portfolio, the system must manage larger aggregate variability and uncertainty in generation.

In contrast to wind, the integration costs for both Solar East and Solar West decrease between 2030 and 2035. This downward trend is driven by portfolio synergy effects: the 2035 system has large deployment of 4-hour battery storage (2800 MW) for resource adequacy purposes, which allows the system to absorb solar variability. Solar generation has a predictable diurnal cycle that is more readily integrated with 4-hour battery technology than wind whose variability is less cyclical and can persist for multiple days.

6. Conclusions

The findings of the 2026 IRP Flexibility Study underscore an important aspect of modern power system planning and the metrics used to determine resource value: as significant load growth and clean energy policies necessitate a transition to a fundamentally different resource mix, portfolio effects are a central consideration in resource planning.

A recurring theme throughout this analysis is that no resource operates in isolation; the flexibility value of a battery and the integration cost of a wind or solar farm are a function of the system into which they are being integrated. As the PGE system reaches higher saturation levels of short-duration storage, the marginal flexibility value of additional battery deployment declines. Conversely, the expansion of the storage fleet can lower the integration costs for solar resources, demonstrating how complementary technologies can be combined into an optimized portfolio.

The flexibility values and costs identified here represent a relatively small component of the overall resource valuation framework deployed in IRP and provide a fine-tuning for PGE's portfolio design. The primary economic drivers remain capital investment, energy value, and, critically in the context of current load-growth trends, resource adequacy. By accounting for the dynamic nature of portfolio effects and continuing to align planning models with operational practices, PGE can navigate the integration of renewable and storage assets into its system.

Appendix R Energy Strategies Analysis

North of Pearl Risk Assessment

Portland General Electric July 2026 IRP Roundtable

July 22, 2026

PGE

ENERGY STRATEGIES

Presentation Contents

1. NOPE Background & High-Level Findings
2. Background on NOPE & PGE 2026 IRP
3. Energy Strategies Scope of Work & Sources
4. Findings from Review of Historic Data
5. Findings from Review of PGE 2035 PCM Modeling
6. Recommendations for PGE Planning Models
7. Conclusions & Next Steps
8. Appendix

NOPE Background & High-Level Findings

NOPE Background & High-Level Findings

- PGE previous IRP modeling assumed 25% of new remote resource capacity could utilize non-firm transmission
- PGE April and May 2026 IRP Roundtables detailed role of Bonneville Power Administration (BPA) flowgates in potentially constraining non-firm transmission availability
- The BPA North of Pearl (NOPE) constraint specifically emerged as a risk to non-firm transmission with past IRP Roundtables stating that NOPE flows > 80% of Total Transfer Capability (TTC) indicate non-firm transmission availability is at risk
- PGE's approach for the coming IRP cycles is to use nodal Production Cost Modeling (PCM) to forecast physical flows on NOPE and to incorporate corresponding forecasts of non-firm availability into downstream zonal portfolio modeling

- Our findings validate and identify:

1. **NOPE flows >80% of TTC as a data-driven threshold indicating non-firm transmission availability risk**
2. **Use of the PCM modeling results to forecast flows and inform zonal portfolio modeling**
3. **Possible refinements to this approach for future IRP cycles**

- *These findings are detailed in the contents of our presentation*

2024-2026 historic data average % of hours NOPE Non-Firm unavailable:

Hour Ending \ Month	1	2	3	4	5	6	7	8	9	10	11	12
1	5%	0%	0%	0%	0%	0%	0%	0%	0%	0%	27%	2%
2	5%	0%	0%	0%	0%	0%	0%	0%	0%	2%	27%	2%
3	3%	0%	0%	0%	0%	0%	0%	0%	0%	2%	25%	2%
4	5%	0%	0%	0%	0%	0%	0%	0%	0%	3%	27%	2%
5	5%	0%	0%	0%	0%	0%	0%	0%	0%	3%	28%	2%
6	6%	2%	2%	0%	0%	0%	0%	0%	0%	3%	32%	2%
7	10%	9%	10%	2%	0%	0%	0%	0%	0%	3%	40%	3%
8	29%	46%	34%	5%	3%	0%	0%	0%	0%	8%	47%	13%
9	45%	57%	55%	5%	6%	2%	0%	2%	3%	21%	47%	18%
10	48%	61%	58%	7%	11%	5%	0%	2%	3%	23%	50%	16%
11	48%	57%	65%	12%	11%	5%	3%	2%	5%	26%	50%	19%
12	50%	57%	63%	8%	11%	8%	5%	5%	5%	24%	50%	21%
13	48%	57%	58%	8%	6%	7%	5%	6%	3%	24%	50%	21%
14	48%	55%	63%	8%	8%	8%	10%	8%	0%	23%	50%	18%
15	47%	57%	60%	8%	8%	10%	15%	10%	2%	21%	50%	18%
16	42%	55%	55%	7%	8%	10%	18%	11%	0%	23%	50%	15%
17	15%	27%	42%	8%	8%	10%	15%	13%	0%	18%	47%	10%
18	16%	0%	19%	5%	6%	7%	11%	10%	0%	10%	47%	13%
19	15%	2%	15%	0%	0%	7%	11%	11%	0%	6%	47%	10%
20	13%	0%	13%	0%	0%	3%	3%	3%	0%	8%	47%	10%
21	11%	7%	11%	0%	0%	3%	0%	3%	0%	10%	43%	8%
22	8%	2%	11%	0%	0%	2%	0%	0%	0%	6%	42%	6%
23	5%	2%	0%	0%	0%	0%	0%	0%	0%	2%	33%	2%
24	5%	0%	0%	0%	0%	0%	0%	0%	0%	3%	30%	2%

2035 Production Cost Modeled % of hours NOPE Non-Firm unavailable:

Hour Ending \ Month	1	2	3	4	5	6	7	8	9	10	11	12
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	20%	39%	6%	0%	0%	0%	0%
8	0%	0%	3%	23%	0%	40%	55%	23%	0%	0%	0%	0%
9	0%	0%	6%	30%	10%	47%	81%	52%	37%	0%	3%	0%
10	0%	7%	23%	43%	13%	57%	90%	61%	57%	0%	17%	0%
11	0%	29%	39%	73%	23%	70%	84%	81%	50%	0%	27%	0%
12	0%	50%	45%	73%	45%	77%	94%	81%	57%	0%	23%	0%
13	0%	46%	42%	90%	68%	73%	84%	71%	50%	3%	23%	0%
14	0%	50%	42%	87%	71%	73%	77%	77%	60%	6%	27%	0%
15	0%	39%	45%	87%	61%	67%	61%	77%	60%	10%	27%	0%
16	0%	29%	52%	87%	58%	50%	55%	52%	47%	6%	20%	0%
17	0%	4%	39%	87%	26%	30%	29%	32%	37%	0%	7%	0%
18	0%	0%	13%	23%	0%	10%	10%	0%	3%	0%	0%	0%
19	0%	0%	3%	7%	0%	0%	6%	0%	0%	0%	0%	0%
20	0%	0%	0%	7%	0%	0%	3%	0%	0%	0%	0%	0%
21	0%	0%	13%	7%	0%	0%	3%	0%	0%	0%	0%	0%
22	0%	0%	0%	7%	0%	0%	3%	0%	0%	0%	0%	0%
23	0%	0%	0%	3%	0%	0%	3%	0%	0%	0%	0%	0%
24	0%	0%	0%	0%	0%	0%	3%	0%	0%	0%	0%	0%

Background from PGE IRP and IRP Roundtables

Background from PGE IRP Update & IRP Roundtables

PGE's IRP update detailed the challenges that the NOPE flowgate poses[1]:

- *During spring of 2024 & 2025 the North of Pearl flowgate reached flow levels near its upper limits*
- *Additionally unscheduled energy flows have been observed coming from the Pacific Northwest and through PGE's service territory*
- *These unscheduled flows have caused BPA to take actions including curtailing approximately 4000 MWs of transmission schedules across the region*

Location of NOPE Flowgate:

- PGE's **April 2026 IRP Roundtable** detailed how high flows lead to risks for non-firm transmission on the NOPE flowgate:
  - *"non-firm transmission can be suspended as a congestion management tool to prevent further loadings on congested flowgates"*[2]
- Thus, non-firm transmission can be unavailable even when the flowgate is below its seasonal TTC
  - This leads to defining the threshold at >= 80% of TTC
  - Still may not capture all conditions where non-firm availability could be impacted

- PGE's **May 2026 IRP Roundtable** proposed threshold for a flowgate to be congested (for non-firm availability) when the flows were >= 80%[3]
  - Nodal Production Cost Modeling (PCM) can be used to simulate how often this occurs in future study years
  - During hours that the flows are >=80%, non-firm transmission is assumed to be unavailable
    - *Previous PGE IRP modeling assumed planned resources would only need **75% of capacity contracted as firm transmission service** and the remainder could be available as non-firm*[4]
  - PGE's current plan is to update IRP modeling to consider when NOPE flows are >= 80% and non-firm transmission is at risk

(1) https://assets.ctfassets.net/416ywc1laqmd/54JgOyxGa8dfAZch4vc54p/db067fc5010d0c23efcd903c56a65cf3/Chapter_4._Transmission_landscape.pdf pp.8
(2) https://assets.ctfassets.net/416ywc1laqmd/5BeH4dfyFys9hQtdBaR4li/61bbbd699da5bd06a6c2dc45b69edba4/CEP_IRP_Roundtable_Apr_8-3.pdf#page=1 pp.21
(3) https://assets.ctfassets.net/416ywc1laqmd/iOtlq68CuHUHy2e6d0Jv7/f822e4294d6c0035a1d75299a83bf491/CEP_IRP_Roundtable_May_20_-_4.pdf#page=1 pp.54
(4) https://assets.ctfassets.net/416ywc1laqmd/54JgOyxGa8dfAZch4vc54p/db067fc5010d0c23efcd903c56a65cf3/Chapter_4._Transmission_landscape.pdf pp.16

Energy Strategies Scope of Work & Sources

Study Process – Detail on Historic & PCM Analysis Methods

Compile & Analyze Historical BPA Constraint Data → **Validate & Analyze PGE PCM Outputs** → **Develop Risk Framework** → **Estimate Future NOPE Risk Exposure** → **Develop Refinements & Recommendations for PGE Planning Models**

2024-2026 Historic:

- Flows over NOPE & other regional flowgates
- PNW & CA Renewable Generation
- PNW & CA Loads

2035 PCM:

- Flows over NOPE & other regional flowgates
- PNW & CA Renewable Generation
- PNW & CA Loads

De-seasonalized Pearson Correlation

Results detailed in following slides and in appendix

		Feb-May (7a-5p)			Jun-Sep (7a-5p)			Oct-Jan (7a-5p)		
Driver	Category	Actuals	PCM 2035	Δ Act-PCM	Actuals	PCM 2035	Δ Act-PCM	Actuals	PCM 2035	Δ Act-PCM
West of Cascades South (E->W)	BPA internal path	+0.64	+0.79	-0.15	+0.67	+0.77	-0.09	+0.61	+0.76	-0.15
COI (northbound)	Intertie flow	+0.34	+0.47	-0.13	+0.45	+0.55	-0.09	+0.51	+0.26	+0.25
PDCI (northbound)	Intertie flow	+0.30	+0.12	+0.18	+0.35	+0.09	+0.26	+0.38	+0.09	+0.29
COI + PDCI (northbound)	Intertie flow	+0.37	+0.47	-0.10	+0.46	+0.55	-0.09	+0.52	+0.28	+0.24
CA net-export	Intertie flow	+0.25	+0.43	-0.18	+0.42	+0.43	-0.02	+0.49	+0.27	+0.23
BPA Wind	BPA generation	+0.48	+0.36	+0.12	+0.34	+0.31	+0.04	+0.23	+0.51	-0.27
BPA / PNW Hydro	BPA generation	-0.16	-0.21	+0.05	-0.26	-0.21	-0.04	-0.19	+0.06	-0.25
PNW load (total)	BA load (north)	+0.12	+0.17	-0.05	+0.13	+0.01	+0.12	+0.34	+0.20	+0.14
BPAT load	BA load (north)	+0.05	+0.19	-0.14	+0.19	+0.04	+0.15	+0.31	+0.20	+0.11
Puget load (PSEI+SCL+TPWR)	BA load (north)	+0.24	+0.11	+0.13	+0.15	+0.09	+0.06	+0.40	+0.20	+0.20
PSEI load	BA load (north)	+0.26	+0.12	+0.13	+0.15	+0.11	+0.04	+0.41	+0.21	+0.19
SCL (Seattle) load	BA load (north)	+0.17	+0.07	+0.10	+0.13	+0.05	+0.08	+0.35	+0.16	+0.18
TPWR (Tacoma) load	BA load (north)	+0.25	+0.11	+0.14	+0.08	+0.04	+0.03	+0.40	+0.19	+0.21
PGE load	BA load (loads path)	+0.06	+0.13	-0.07	+0.19	+0.04	+0.14	+0.20	+0.13	+0.07
PACW load	BA load (south)	+0.06	+0.15	-0.08	-0.09	-0.06	-0.03	+0.29	+0.13	+0.17
South load (PGE+PACW)	BA load (south)	+0.06	+0.14	-0.08	+0.05	-0.01	+0.06	+0.25	+0.13	+0.12
CISO (California) load	BA load (south/CA)	-0.34	-0.07	-0.26	-0.34	-0.24	-0.10	-0.19	-0.11	-0.08
CISO Solar	CA generation	-0.07	+0.39	-0.46	+0.12	+0.30	-0.18	+0.06	+0.09	-0.02

Outputs:

- "De-seasonalized" correlations that control for seasonal and diurnal relationships.
- Answers the question: *"When NOPE has a peak flow day, what else tends to peak with it?"*

Source	What it provides
BPA Interties & Flowgates	Path Actual flow (MW) + TTC: NOPE, COI, PDCI, West of Cascades-South.
BPA BA Load & VER feed	5-min BA Load, Wind, Hydro, Thermal, Net Interchange (Pacific; archives to 2007).
EIA-930 – Hourly Electric Grid Monitor	Hourly demand by BA, generation by fuel, and interchange (BA-level; 2019→).
EIA-923	Monthly per-plant hydro generation, WA/OR/ID (primeMover = HY; 2019→).
BPA Hourly Firm Data Monitoring & Evaluation	TC-20 Report (actual firm/non-firm curtailments) + TLR Avoidance Summary; 2008→.
BPA OASIS (OATI)	ATC (System Data Summary report), Outages (Notices: Message Summary report), Operational message log; reliability-curtailment & congestion postings.
CAISO OASIS	NOPE flowgate shadow prices (indicative of EIM (Energy Imbalance Market) binding)

- Interpretation:
  - Estimate Future NOPE Risk Exposure
    - Corroborate PGE's current approach
  - Develop Refinements and Recommendations for future PGE Modeling
    - Provide possible future refinements to use in following IRP cycles

Findings from Review of Historic Data

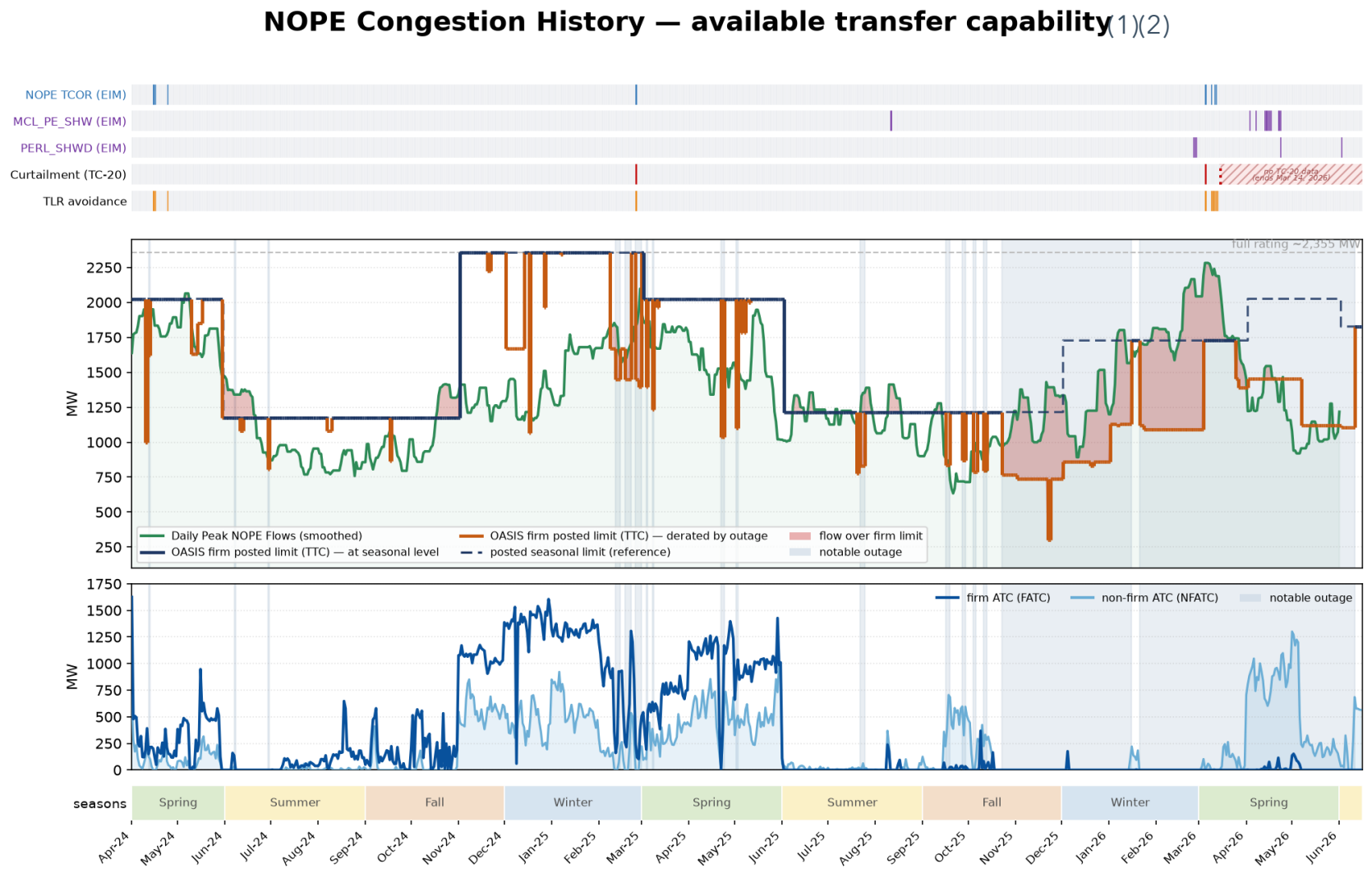
Overview of Historic NOPE Congestion

What did we look at when attempting to characterize historical congestion

- Curtailment (TC-20)
- TLR-Avoidance
- EIM Binding (NOPE & Constituent Lines)
- NOPE Flows, TTC, and Outages
- Firm/Non-Firm ATC availability

Historically, NOPE Non-firm transmission availability has been extremely limited during the summer months and periods of extensive planned outages

Non-firm ATC historically goes to 0 when flows approach TTC

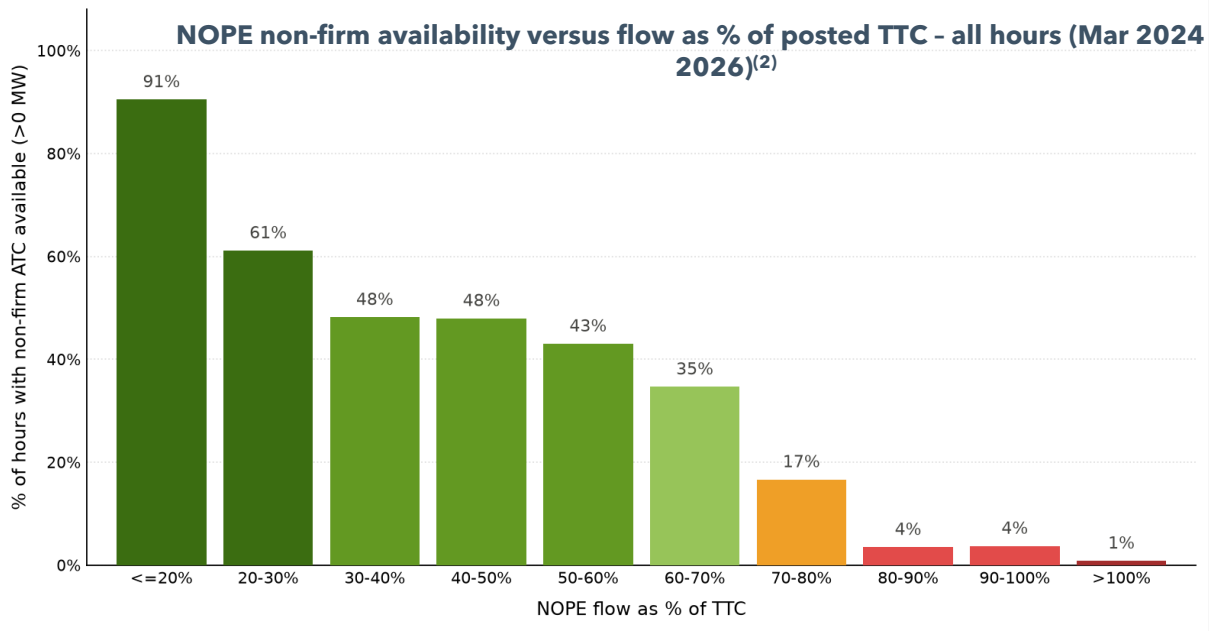


Sources: (1) BPA Flows, Curtailment & TLR Avoidance, ATC OASIS System Data Summary report for "W/BPAT/NOPE_S>N//"
(2) CAISO Intertie Constraint Shadow Prices

Acronyms: TLR – Transmission Loading Relief, EIM – Energy Imbalance Market, TTC – Total Transfer Capability, ATC – Available Transfer Capability

NOPE ATC vs Flow & 2 Years Historic Data 12x24 Heatmap

- **Non-firm transmission is the interruptible, short-term tranche of transfer capability:**
  - It can't be reserved long-term, it's the first product curtailed to relieve congestion, and it can be suspended as a congestion-management tool even when the flowgate is below its seasonal TTC[1]
- **As flows on NOPE exceed 80% of posted TTC historically, non-firm ATC increasingly unavailable**
  - The figure confirms this empirically: non-firm ATC is available in ~91% of hours when flow is ≤20% of TTC, falling to ~4% in the 80–90% band and ~1% above TTC (x-axis = NOPE hourly peak flow as % of TTC; y-axis = % of hours with non-firm ATC available)
  - The headroom between TTC and flow is the proxy for incremental non-firm availability; comparing forecasted or historical flow to an 80%-of-TTC threshold is a practical, observable way to forecast non-firm availability without reproducing the full ATC accounting (a proxy, not exact – schedules and market dispatch also drive flow)



- Using two years of 15-minute historic data[3] we can see the temporal occurrence of NOPE flows hitting >80% of TTC:
  - Hours with >80% of NOPE TTC occur primarily in spring and fall on peak hours
  - **Strong confounding factor is TTC derates that happened with planned outages in late 2025 and early 2026**

Historic 2 year % of days at each hour for each month that NOPE >80% (100% means every hour of each day that month)

Hour Ending \ Month	1	2	3	4	5	6	7	8	9	10	11	12
1	5%	0%	0%	0%	0%	0%	0%	0%	0%	0%	27%	2%
2	5%	0%	0%	0%	0%	0%	0%	0%	0%	2%	27%	2%
3	3%	0%	0%	0%	0%	0%	0%	0%	0%	2%	25%	2%
4	5%	0%	0%	0%	0%	0%	0%	0%	0%	3%	27%	2%
5	5%	0%	0%	0%	0%	0%	0%	0%	0%	3%	28%	2%
6	6%	2%	2%	0%	0%	0%	0%	0%	0%	3%	32%	2%
7	10%	9%	10%	2%	0%	0%	0%	0%	0%	3%	40%	3%
8	29%	46%	34%	5%	3%	0%	0%	0%	0%	8%	47%	13%
9	45%	57%	55%	5%	6%	2%	0%	2%	3%	21%	47%	18%
10	48%	61%	58%	7%	11%	5%	0%	2%	3%	23%	50%	16%
11	48%	57%	65%	12%	11%	5%	3%	2%	5%	26%	50%	19%
12	50%	57%	63%	8%	11%	8%	5%	5%	5%	24%	50%	21%
13	48%	57%	58%	8%	6%	7%	5%	6%	3%	24%	50%	21%
14	48%	55%	63%	8%	8%	8%	10%	8%	0%	23%	50%	18%
15	47%	57%	60%	8%	8%	10%	15%	10%	2%	21%	50%	18%
16	42%	55%	55%	7%	8%	10%	18%	11%	0%	23%	50%	15%
17	15%	27%	42%	8%	8%	10%	15%	13%	0%	18%	47%	10%
18	16%	0%	19%	5%	6%	7%	11%	10%	0%	10%	47%	13%
19	15%	2%	15%	0%	0%	7%	11%	11%	0%	6%	47%	10%
20	13%	0%	13%	0%	0%	3%	3%	3%	0%	8%	47%	10%
21	11%	7%	11%	0%	0%	3%	0%	3%	0%	10%	43%	8%
22	8%	2%	11%	0%	0%	2%	0%	0%	0%	6%	42%	6%
23	5%	2%	0%	0%	0%	0%	0%	0%	0%	2%	33%	2%
24	5%	0%	0%	0%	0%	0%	0%	0%	0%	3%	30%	2%

Sources: (1) PGE April 2026 IRP Roundtable pp 21; (2) ATC OASIS System Data Summary report for "W/BPAT/NOPE_S>N//"; (3) BPA Flows

Findings from Review of PGE 2035 PCM Modeling

PCM Modeled Outputs 12x24 Heatmap & Top Correlations

- With magnitude of solar additions in 2035 model versus 06/2024-06/2026 actuals, magnitude of hours with >80% seasonal TTC from 2035 PCM outputs[1] increases to >24 days out of 30 and shifts from February and March to April and July
  - Stands as an indicator of increasing role of solar, though wind still correlates highly through most of the year

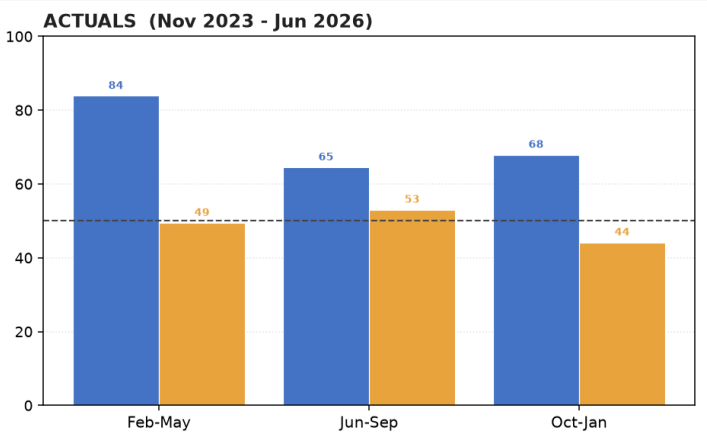
PCM modeled 2035 % of days at each hour for each month that NOPE >80% (100% means every hour of each day that month)

Hour Ending \ Month	1	2	3	4	5	6	7	8	9	10	11	12
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	20%	39%	6%	0%	0%	0%	0%
8	0%	0%	3%	23%	0%	40%	55%	23%	0%	0%	0%	0%
9	0%	0%	6%	30%	10%	47%	81%	52%	37%	0%	3%	0%
10	0%	7%	23%	43%	13%	57%	90%	61%	57%	0%	17%	0%
11	0%	29%	39%	73%	23%	70%	84%	81%	50%	0%	27%	0%
12	0%	50%	45%	73%	45%	77%	94%	81%	57%	0%	23%	0%
13	0%	46%	42%	90%	68%	73%	84%	71%	50%	3%	23%	0%
14	0%	50%	42%	87%	71%	73%	77%	77%	60%	6%	27%	0%
15	0%	39%	45%	87%	61%	67%	61%	77%	60%	10%	27%	0%
16	0%	29%	52%	87%	58%	50%	55%	52%	47%	6%	20%	0%
17	0%	4%	39%	87%	26%	30%	29%	32%	37%	0%	7%	0%
18	0%	0%	13%	23%	0%	10%	10%	0%	3%	0%	0%	0%
19	0%	0%	3%	7%	0%	0%	6%	0%	0%	0%	0%	0%
20	0%	0%	0%	7%	0%	0%	3%	0%	0%	0%	0%	0%
21	0%	0%	13%	7%	0%	0%	3%	0%	0%	0%	0%	0%
22	0%	0%	0%	7%	0%	0%	3%	0%	0%	0%	0%	0%
23	0%	0%	0%	3%	0%	0%	3%	0%	0%	0%	0%	0%
24	0%	0%	0%	0%	0%	0%	3%	0%	0%	0%	0%	0%

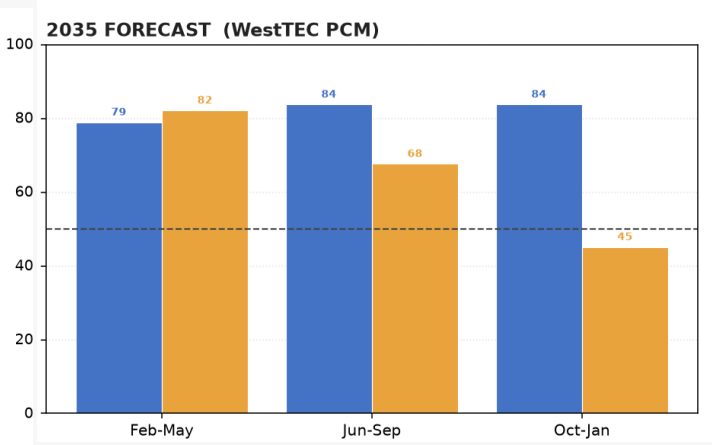
Sources: (1) PGE WestTEC adjusted PCM outputs with NOPE not binding for TTC

CA Solar and BPA Wind Percentiles on the Top 10% of NOPE Flow Days (7am-5pm) Historic vs PCM (showing correlations from 0-100% on highest NOPE days median versus each day's +/- 15 day local normal)

- In 2+ years of historic data, Pacific Northwest (PNW) wind had the highest correlation with top 10% flow periods of flow on NOPE



- In 2035 PCM modeling, solar emerges as highest correlation factor in springtime, however PNW wind continues to dominate correlations through rest of the year



Pearson Correlation Analysis – Summary Results

The correlation analysis shows renewable generation and load drivers as normalized covariant components, isolating the underlying signals that move with south to north NOPE flow after seasonality is stripped out

- Positive values show increases in the factor with S->N NOPE flows, negative values show a factor that decreases when NOPE flows increase
- This analysis considered correlations with factors against NOPE flow in general and not conditioned on congestion or on the ≥80%-of-TTC threshold (see appendix for details)
- In the historic data PNW wind (measured as wind in the BPA region) has the highest covariance, in the PCM modeled data CA net solar (California solar minus California load) also emerges as strong factor covariant with NOPE flows
- PNW load, primarily captured as PGE + Puget Sound load, also has high covariance some times of the year

- **Based on this statistical analysis, PNW Wind, CA Net Solar and PNW load values were chosen as exogenous predictive factors to consider when forecasting NOPE flows (and non-firm unavailability) for years and conditions independent of PCM unit dispatch results**

		Feb-May (7a-5p)			Jun-Sep (7a-5p)			Oct-Jan (7a-5p)		
Factor	Category	Historic	PCM 2035	Δ Act-PCM	Historic	PCM 2035	Δ Act-PCM	Historic	PCM 2035	Δ Act-PCM
COI + PDCI (northbound)	Intertie flow	+0.37	+0.47	-0.10	+0.46	+0.55	-0.09	+0.52	+0.28	+0.24
CA net-export	Intertie flow	+0.25	+0.43	-0.18	+0.42	+0.43	-0.02	+0.49	+0.27	+0.23
BPA Wind	**BPA generation**	**+0.48**	**+0.36**	**+0.12**	**+0.34**	**+0.31**	**+0.04**	**+0.23**	**+0.51**	**-0.27**
PNW load (total)	BA load (north)	+0.12	+0.17	-0.05	+0.13	+0.01	+0.12	+0.34	+0.20	+0.14
CISO (California) load	BA load (south/CA)	-0.34	-0.07	-0.26	-0.34	-0.24	-0.10	-0.19	-0.11	-0.08
CISO Solar	**CA generation**	**-0.07**	**+0.39**	**-0.46**	**+0.12**	**+0.30**	**-0.18**	**+0.06**	**+0.09**	**-0.02**
BPA / PNW Hydro	BPA generation	-0.16	-0.21	+0.05	-0.26	-0.21	-0.04	-0.19	+0.06	-0.25

Recommendations for PGE Future Planning Models

Future Modeling: Incorporating Findings from PCM into Aurora

Modeling flow on NOPE from exogenous zonal input variables

- Use 2035 PCM case modeled flow as a target to train a regression model
- The regression model outputs hourly flow against BPA seasonal TTC limits by using input variables as they relate to PCM modeled NOPE flows, then determines the likely congested state as hours when flows are >80% of seasonal TTC

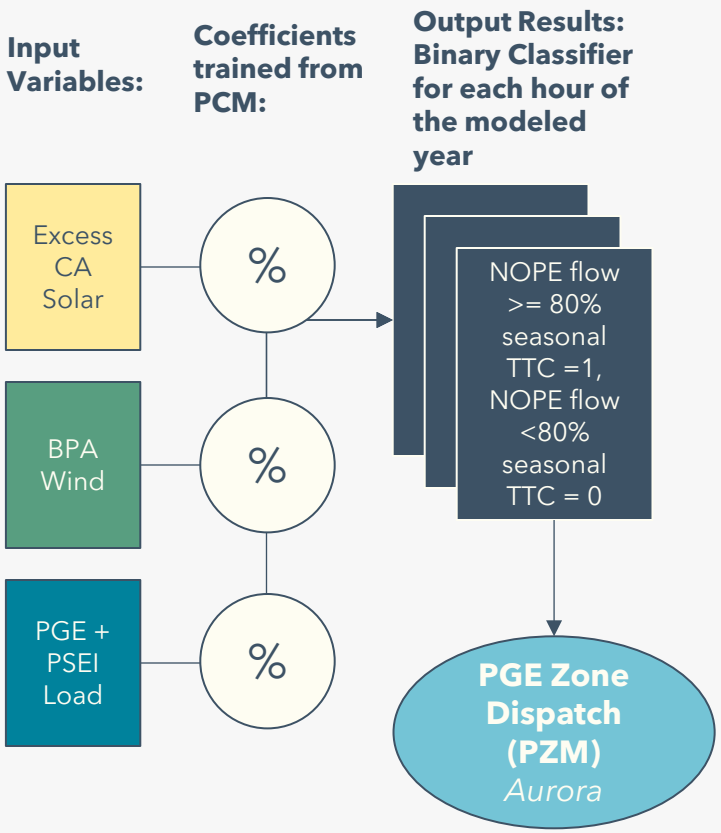
Input Variables

- Excess CA Solar
  - Determined by obtaining positive values for CISO solar output minus CISO load
- BPA Wind
  - Wind output for the BPAT region
- PNW Load (west-wide only)
  - Sum of PGE and PSEI area load

Results

- Binary Classifier 1 = NOPE flow at hour expected to be >= 80% seasonal TTC, 0 = < 80% seasonal TTC
- Can be run each year for Aurora using different annual sets of above input variables

- The results show **1,489 hours** of the year (vs. **1,333 hours in the PCM**) where NOPE flows would exceed 80% of seasonal TTC and as a result indicate risk for the ability to obtain non-firm transmission service
- The regression can be further refined by using multiple PCM results derived from different weather years before using in future IRP cycle Aurora modeling



Result Category	2035 PCM	Predicted
True Positives (TP)		941
False Positives (FP)		548
Total Positives	1,333	1,489
False Negatives (FN)		392
True Negatives (TN)		6,879
Total Negatives	7,427	7,271
Total		8,760
Balanced Accuracy		**0.816**

Predicted 2035 % of days at each hour for each month that NOPE >80% (100% means every hour of each day that month)

Hour Ending \ Month	1	2	3	4	5	6	7	8	9	10	11	12
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
8	0%	0%	0%	0%	0%	23%	3%	0%	0%	0%	0%	0%
9	0%	0%	0%	47%	29%	80%	55%	48%	67%	0%	0%	0%
10	0%	18%	19%	67%	58%	90%	84%	94%	87%	16%	7%	0%
11	0%	54%	48%	83%	84%	93%	87%	97%	100%	35%	33%	0%
12	0%	61%	61%	100%	87%	97%	87%	97%	97%	48%	53%	0%
13	0%	75%	58%	100%	84%	100%	81%	87%	97%	55%	60%	0%
14	0%	75%	61%	100%	77%	93%	65%	68%	70%	52%	53%	0%
15	0%	61%	48%	93%	65%	87%	48%	45%	33%	16%	13%	0%
16	0%	39%	26%	70%	35%	60%	32%	29%	10%	0%	0%	0%
17	0%	0%	0%	7%	3%	7%	19%	13%	0%	0%	0%	0%
18	0%	0%	0%	0%	0%	3%	16%	13%	0%	0%	0%	0%
19	0%	0%	0%	0%	0%	3%	19%	13%	0%	0%	0%	0%
20	0%	0%	0%	0%	0%	3%	16%	13%	0%	0%	0%	0%
21	0%	0%	0%	0%	0%	0%	13%	10%	0%	0%	0%	0%
22	0%	0%	0%	0%	0%	0%	13%	10%	0%	0%	0%	0%
23	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
24	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Conclusions & Next Steps

Findings

PGE NOPE Flows >= 80% of Seasonal TTC is a reliable risk metric for non-firm ATC availability in the historic data

Current IRP modeling approach to use PCM results for NOPE flows to estimate non-firm transmission risk is a useful update to past assumptions around 25% non-firm availability year round

Analysis of historic data and 2035 PCM modeling also can be used to identify a set of factors that are covariant with NOPE flows

High CA solar net of load, PNW wind output and PNW load have strongest correlation with high NOPE flows in the PCM

In future IRP cycles, these factors can be used to estimate NOPE flows using a regression model trained on PCM-generated flows across multiple weather years and applied within Aurora

Recommendations

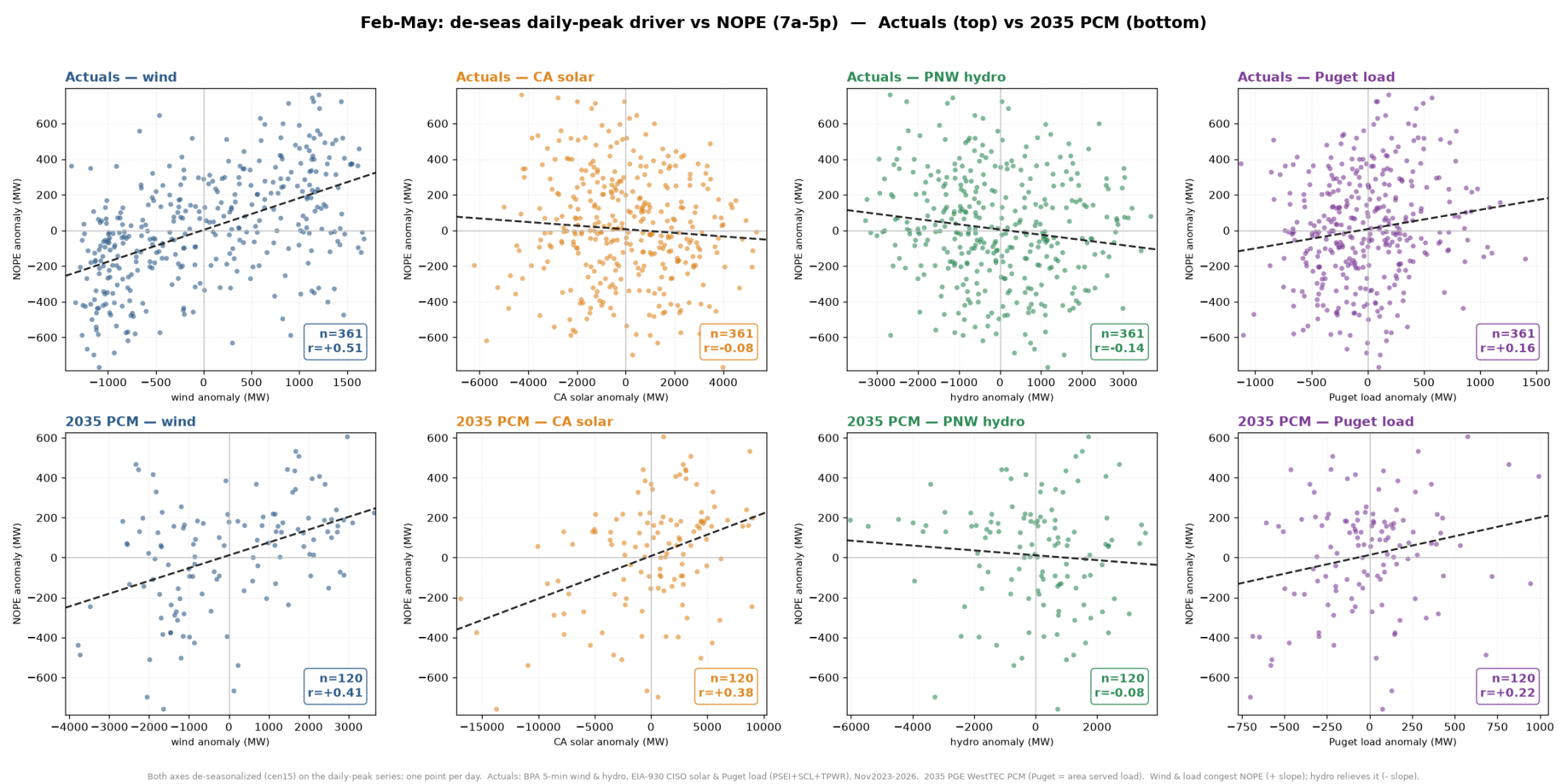
In the current IRP cycle, retain 80% of NOPE seasonal TTC in modeling as a proxy for likely congestion and unavailability of non-firm transmission

In future IRP cycles, consider implementing a weather-year generalized regression model informed by PCM-generated flows across multiple weather years within Aurora as a proxy for non-firm transmission availability on NOPE

- This will allow future study years and the capacity expansion model to consider non-firm availability on NOPE subject to changing system conditions across the West
- Doing so should help PGE's modeling tools better assess non-firm transmission availability risks and arrive at a lower-risk resource portfolio

Appendix – IRP Roundtable

Top Individual Correlated Factors Scatter Plots



Correlation Analysis - Details

The de-seasonalized Pearson Correlation (PC) analysis decomposes correlated renewable generation and load drivers into normalized covariant components, isolating the underlying signals that move NOPE after seasonality is stripped out

- This correlation analysis is computed on de-seasonalized daily-peak NOPE flow across all days in each seasonal bucket, in the S→N (northbound) direction

- **These correlations describe what moves NOPE flow in general – they are not conditioned on congestion or on the ≥80%-of-TTC threshold**
  - Identifying when flow crosses 80% of seasonal TTC is the job of the regression/binary classifier shown later, which is equally valuable for identifying hours below 80% as above it – We deliberately did not condition the correlations on only the ≥80% hours
  - Conditioning the correlations on only the ≥80% hours would restrict the fit to a small, rare subset – roughly 15% of hours in the 2035 PCM (1,333 of 8,760), and fewer still in the ~2-year historic record – drawn from a single PCM weather year.
  - With so few congested observations and no weather-year variation, the fitted relationships would tend to track noise particular to those hours rather than drivers that generalize.
  - Correlating on flow across all hours retains the full signal and lets the same drivers explain both congested and non-congested conditions, which is what the downstream classifier needs.

		Feb-May (7a-5p)			Jun-Sep (7a-5p)			Oct-Jan (7a-5p)		
Driver	Category	Actuals	PCM 2035	Δ Act-PCM	Actuals	PCM 2035	Δ Act-PCM	Actuals	PCM 2035	Δ Act-PCM
West of Cascades South (E->W)	BPA internal path	+0.64	+0.79	-0.15	+0.67	+0.77	-0.09	+0.61	+0.76	-0.15
COI (northbound)	Intertie flow	+0.34	+0.47	-0.13	+0.45	+0.55	-0.09	+0.51	+0.26	+0.25
PDCI (northbound)	Intertie flow	+0.30	+0.12	+0.18	+0.35	+0.09	+0.26	+0.38	+0.09	+0.29
COI + PDCI (northbound)	Intertie flow	+0.37	+0.47	-0.10	+0.46	+0.55	-0.09	+0.52	+0.28	+0.24
CA net-export	Intertie flow	+0.25	+0.43	-0.18	+0.42	+0.43	-0.02	+0.49	+0.27	+0.23
BPA Wind	BPA generation	+0.48	+0.36	+0.12	+0.34	+0.31	+0.04	+0.23	+0.51	-0.27
BPA / PNW Hydro	BPA generation	-0.16	-0.21	+0.05	-0.26	-0.21	-0.04	-0.19	+0.06	-0.25
PNW load (total)	BA load (north)	+0.12	+0.17	-0.05	+0.13	+0.01	+0.12	+0.34	+0.20	+0.14
BPAT load	BA load (north)	+0.05	+0.19	-0.14	+0.19	+0.04	+0.15	+0.31	+0.20	+0.11
Puget load (PSEI+SCL+TPWR)	BA load (north)	+0.24	+0.11	+0.13	+0.15	+0.09	+0.06	+0.40	+0.20	+0.20
PSEI load	BA load (north)	+0.26	+0.12	+0.13	+0.15	+0.11	+0.04	+0.41	+0.21	+0.19
SCL (Seattle) load	BA load (north)	+0.17	+0.07	+0.10	+0.13	+0.05	+0.08	+0.35	+0.16	+0.18
TPWR (Tacoma) load	BA load (north)	+0.25	+0.11	+0.14	+0.08	+0.04	+0.03	+0.40	+0.19	+0.21
PGE load	BA load (loads path)	+0.06	+0.13	-0.07	+0.19	+0.04	+0.14	+0.20	+0.13	+0.07
PACW load	BA load (south)	+0.06	+0.15	-0.08	-0.09	-0.06	-0.03	+0.29	+0.13	+0.17
South load (PGE+PACW)	BA load (south)	+0.06	+0.14	-0.08	+0.05	-0.01	+0.06	+0.25	+0.13	+0.12
CISO (California) load	BA load (south/CA)	-0.34	-0.07	-0.26	-0.34	-0.24	-0.10	-0.19	-0.11	-0.08
CISO Solar	CA generation	-0.07	+0.39	-0.46	+0.12	+0.30	-0.18	+0.06	+0.09	-0.02