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September 6, 2023

Via Electronic Filing

Public Utility Commission of Oregon
Attention: Filing Center
P.O. Box 1088
Salem, OR 97308-1088

Re: LC 80 – Portland General Electric Company's 2023 Clean Energy Plan and Integrated Resource Plan
Reply to Round 1 Comments

Dear Filing Center:

Enclosed for filing today in the above-referenced docket is Portland General Electric Company's (PGE) replies to Round 1 Staff and stakeholder comments on PGE's 2023 Clean Energy Plan (CEP) and Integrated Resource Plan (IRP).

PGE has sought to respond to each point of feedback included in Staff and stakeholders' Round 1 comments. Appendix A to PGE's response lists each comment and references the chapter in which it is addressed. PGE looks forward to engaging in further discussion of these topics and providing additional information on remaining questions at the upcoming LC 80 workshops on September 14th and 22nd.

Kristen Sheeran, PGE's Senior Director of Strategy Integration and Planning, leads PGE's CEP and IRP work. Please direct any questions or communications regarding these comments to: pge.opuc.filings@pgn.com.

Sincerely,

/s/ Riley Peck

Riley Peck
Senior Manager, Regulatory Strategy
Resource & Regulatory Strategy

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Introduction

PGE offers these Reply Comments in response to the Round 1 Comments filed by 13 different stakeholder groups in the LC 80 docket.[1] The Company appreciates the work that stakeholders have devoted towards PGE's 2023 CEP/IRP, and PGE has benefited from the reflections on the important considerations for both this and future CEP/IRP cycles.

While we have sought to respond to each question or suggestion (as summarized in **Appendix A: Comment and Response Crosswalk**), we have focused incremental analytical work on several high-priority areas where modeling refinements appeared to us to be able to most meaningfully inform consequential topics raised by stakeholders. These topics include transmission, energy efficiency, modeling considerations and portfolio analysis. As part of the new analysis responding to stakeholders' concerns, we have included a revised Preferred Portfolio which is provided in **Section 6.3**.

While there are many modeling improvements discussed below, PGE continues to believe that the CEP/IRP Action Plan aligns with the state's public policy goals and mitigates risks for customers while balancing affordability and emissions reduction during a highly dynamic period of change for our industry.

[1] A 14^{th} was filed but were the same comments to which PGE responded in its 5/31 Round 0 comments.

Chapter 1. Decarbonization Plan

1.1 Clean Energy Plan

The Oregon Public Utility Commission Staff (Staff) has stated that PGE has not fully answered questions in long-term decarbonization planning.[2] It states that PGE has glossed over compliance obstacles and has not provided sufficient detail to allow the consideration of future options and trade-offs. Further, Staff requests additional discussion about the risk associated with the actions in the CEP/IRP, including the economic, technical feasibility, and implementation risks. Finally, Staff posed five questions to PGE that seek more detail on the Company's long-term decarbonization strategy.

PGE's response

PGE's 2023 CEP/IRP undertook a significant effort to balance system reliability, affordability for customers, and emissions reductions in the determination of what additional supply-side, demand-side, distributed energy resources, energy efficiency, and transmission resources would be required to meet the emissions targets established in HB 2021. Based on PGE's current long-term modeling processes, the plan articulates the general characteristics of incremental resources that will be needed over the remainder of the decade to reach the targets binding 2030 and beyond. To reduce emissions, PGE needs to replace thermal generation and purchases with non-emitting energy and capacity resources, while working with customers to shave or shift peak loads through energy efficiency, demand response, and management of flexible loads.

Absent HB 2021 there would still be significant resource need, driven by accelerating load growth, existing contract expirations, RPS obligations, and the requirement for small-scale renewables. However, a main finding from the 2023 CEP/IRP was that an unprecedented quantity of additional incremental generation resources and transmission capacity are needed to meet the 2030 target. Importantly, the CEP/IRP modeling also found that the resources needed to meet the 2030 target are economically and technically feasible.

Beyond 2030, and specifically to achieve the 2040 zero emissions target, the modeling shows that additional non-emitting resource technologies that are not currently economically or technically feasible will be needed to replace thermal generation as a backstop resource for reliability. This finding is consistent with numerous regional and national studies of pathways to deep decarbonization, net zero, or 100 percent emissions free targets. In the 2023 CEP/IRP, PGE was unwilling to speculate on which specific non-emitting technologies (e.g.,

[2] LC 80 Round One Comments of Staff at 7

hydrogen, nuclear, CCS, etc.) or combinations thereof and their costs will emerge over the next decade or more to advance decarbonization in the power sector. Instead, our longer-term modeling to 2040 detailed the key characteristics of those resources and the quantities that would be required to serve retail load with zero associated emissions while maintaining reliability and affordability.

Our decarbonization path modeled in the 2023 CEP/IRP is based on the best information that is known and available today and will almost certainly evolve as technologies, markets, and modeling improve. Importantly, the near-term resource actions proposed in PGE's Action Plan are the appropriate 'no regrets' next steps to meet the 2030 target and position our system for compliance with targets in 2035 and 2040, no matter how future technologies evolve. The resource need is so significant that the acquisition over the next several years of incremental non-emitting energy and capacity resources on our system is unavoidable under any future scenario of new technology development. None of the resource actions in PGE's proposed Action Plan preclude the future adoption of emergent technologies, including those that will enable PGE to aggregate and manage flexible loads to shave and/or shift peak energy needs. Our Action Plan proposes the near-term resource actions that balance cost, reliability, and emissions that best position PGE for success in achieving the 2030 target and targets beyond. Delaying action today for greater clarity on the development of future technologies that our modeling doesn't indicate are needed between now and 2030 will almost assuredly mean the company cannot meet the 2030 target.

With regards to the pathway to the 2030 target for which the commercial availability and costs of non-emitting technologies are better known, the modeling demonstrates that additional non-emitting energy and capacity generation resources are needed on PGE's system to reduce existing thermal generation and purchases with associated emissions sufficiently to achieve emissions targets. Coal from our contractual obligations to Colstrip will no longer be used to serve retail load by 2030. The modeling shows natural gas serving as a critical reliability backstop resource for our system, a need that was demonstrated most recently during the heat event the week of August 13th when our system broke another peak load record. Simply reducing existing thermal output to the required emission levels while not bringing on additional generation and capacity creates a system forecasted to be inadequate for reliability. These findings, again, are consistent with other studies of long-term decarbonization, which generally all suggest a large increase in non-emitting generation is required to meet emission reduction goals. Accordingly, it is a straightforward statement to say that many of the energy and transmission resources identified in the 2023 CEP/IRP, including utility scale wind, solar, and batteries, as well as distributed solar paired with storage, demand response, and energy efficiency are needed for HB 2021 compliance. That is why all these resources feature prominently in our proposed Action Plan.

Customer affordability must remain front and center as we decarbonize. Optionality and flexibility will be key as markets and the procurement environment evolve over time. This is why the 2023 CEP/IRP is filed and updated on a regular cadence with the Commission, to account for changing economic and market conditions, technologies, and customer needs.

As discussed at great length in the CEP/IRP, PGE evaluated different scenarios for achieving the mandated emissions targets, including earlier or later decarbonization resource actions between now and 2030. Our modeling shows that those strategies, while consistent with meeting the emissions targets in HB 2021, pose higher risks and rate pressures for our customers. The linear path to emissions reduction detailed in the CEP/IRP best balances costs and community benefit with the likelihood of achieving the emission target by 2030.

To add an unprecedented amount of new non-emitting generation and transmission capacity under any of the evaluated scenarios, while expanding demand response, small-scale and community based renewable energy resources, and energy efficiency, however, is not without risk, as discussed in our CEP/IRP. The market's ability to site new resources and transmission; persisting supply chain constraints and challenging labor market dynamics; and the process time to buy, build, or otherwise secure access to new resources on our system is challenging. Our CEP/IRP is also forecasting load growth in a period of heightened uncertainty, because of new federal, state, and local policy drivers accelerating electrification and economic growth in key energy-intensive sectors in our service territory.

Climate impacts and weather uncertainty continue to challenge the reliability of the Western grid and the availability of hydro and wind resources. Market price volatility resulting from these and other dynamics challenge our ability to maintain affordability while we decarbonize. As other Western states decarbonize under similarly ambitious policy directives, the region will confront an increased scarcity of developable lands for new generation, transmission constraints and growing risks for resource curtailment. Some of these constraints can be alleviated by regional partnerships and collaboration and the growth and expansion of organized markets. PGE actively cooperates with BPA, CAISO, other entities, utilities, and energy suppliers across the West to support decarbonization goals and planning.

Despite these risks, we are pleased with recent successes since we filed the CEP/IRP in March: the acquisition of 475 MW of battery storage on our system and the recent announcement by BPA that will address some of our most immediate transmission constraints. We are taking all appropriate steps to accelerate the acquisition of resources and alleviation of transmission constraints and stand behind the path identified in the CEP/IRP as the right path to the emissions target for our customers. We are also engaging in regional discussions to improve the accounting and specificity of market purchases to ensure all non-emitting resources imported to our system are accounted for appropriately.

As the path we identified in the CEP/IRP is the least-cost, least-risk path to the emissions targets, deviations from that path based on what we know today imply increased cost and risk of the system becoming resource inadequate. To contemplate pursuit of other options would require further discussion and direction from the Commission regarding the cost and reliability pauses referenced in HB 2021. Possible options include resources that the model did not select as cost-effective during this time horizon (e.g., pumped storage) or increased reliance on market purchases, which presents significant market price volatility and risks to our customers. Our modeling also shows that the aggregated sizes of the potential alternatives are insufficient to meet PGE's increasing need.

As mentioned above, there is no prudent path to the 2030 emissions targets on PGE's system that does not involve taking the near-term resource actions identified in the proposed Action Plan. Accordingly, this set of incremental resource additions can be viewed as 'no-regrets'. To increase the likelihood of acquiring the necessary resources on time and at the lowest possible cost for our customers, a more flexible acquisition process that can allow us to prioritize better market data with multiple acquisition windows to ensure we're acquiring the best value resources at the lowest cost will be very helpful, as we discuss in our July 17 filing in UM 2274.

Beyond 2030 we demonstrate, based on what we believe today, how much additional non-emitting energy and capacity will be needed to fully replace the role of thermal generation on our system. Key drivers such as technological advancement and market evolution will determine which resources will be most beneficial to replace them.

Turning to Staff's specific questions:

> *Will PGE's plan be feasible without future market interactions and market participation?*

The incremental resources included in the Action Plan of this CEP/IRP are based on the current structure of market organization.[3] As discussed above, there are many unquantifiable risks included in PGE's CEP/IRP that could prevent the full realization of the plan; supply chains, labor availability, and development policy could each create significant headwinds to sufficient resource acquisition. Further, the economic impacts of those resource additions should be considered carefully. Currently, PGE projects a nominal 7.6 percent compounding average growth rate between 2024 and 2030, representing a ~37 percent increase in the real costs associated with generation resources. These projected cost increases present a risk to the plan's feasibility and addressing those cost increases, especially to lower-income and historically marginalized communities, will be a significant challenge.

[3] As both the impacts of market redesign on system requirements can vary widely and the wide uncertainty about potential future market developments, PGE's IRPs have generally not invested much attention towards potential market developments. The most certainty available today is the development of the WRAP, though there are many open questions about the methodologies as well as the integration of another planning jurisdictions (both discussed below in **Section 4.3.2.1, WRAP and CEP/IRP adequacy**).

It is possible that the development of a new and/or expanded market structure could more efficiently allocate resources and reduce the size of required incremental resource additions (and their associated costs). There is some analysis in the filed CEP/IRP envisioning these potential benefits, but they provide limited value as the results are highly sensitive to the input assumptions. PGE is actively participating in the development and expansion of organized markets and looks forward to working with Staff and stakeholders to adjust its long-term planning processes to fit the most expected market design.

> *Where are there junctures at which the Company might consider material changes in strategy that go beyond procurement volumes, for example adopting operating constraints on emitting resources, adjusting transmission requirements for renewables, joining an RTO, or other alternatives?*

PGE first notes that procurement targets will likely change between now and 2030 for two main reasons. The first, updated forecasts of system need, is the most intuitive, especially after the significant increase in estimated system need in the July 7th Addendum. However, the second, improved modeling capacity, could be equally important. The CEP/IRP modified what long-term planning tools it had available to incorporate appropriate emission accounting methodologies and address several new requirements and expectations. The realities of integrating variable generation will require additional improvements in PGE's modeling capabilities. Some of these improvements are discussed below in **Section 4.7.1, Hourly analysis of the Preferred Portfolio**, and some were discussed in the March 2023 IRP roundtable; however, further work is needed to develop a better understanding of the operational and financial challenges and opportunities of intermittent generation as the total MWs on PGE's system (and that of the region) increases. Additionally, changes to market structure could be a third driver of a change in resource need if they materialize.

PGE continues to evaluate transmission requirements for its owned and contracted off-system generation resources. The Company notes it has been responsive to stakeholder and Commission input in recent procurements reducing levels of required firm transmission. However, PGE notes that adjusting transmission requirements for renewables can increase risk to customers. As noted below in **Section 2.1, Comprehensive transmission comments**, as part of WRAP compliance obligations PGE is expected in the day of operations to have 100 percent of energy delivered to load on firm transmission. The reduction of expected capacity contribution to PGE's system as well as to the WRAP could decrease the cost-effectiveness of certain projects. To mitigate this risk PGE will continue to work with regional peers and stakeholders to establish risk-adjusted no regrets strategies, such as accelerating new build of transmission, seeking regional portfolio diversity, exploring an RTO, and taking the highest-value transmission products when they're available.

Operational limits on thermal generation do not change PGE's resource strategy. The modeling assumes a fixed carbon budget from thermal generation consistent with the HB 2021 emissions targets. Holding thermal generation fixed without substituting that power on the system with sufficient non-emitting energy and capacity resources would lead to a system that is resource inadequate. Hence, PGE's strategy must include replacing thermal generation and purchases with sufficient non-emitting energy and capacity resources. The specific resources or combinations therein that offset the need for thermal generation will be determined primarily through competitive bidding processes. But there is no physical path to serving our customers' energy needs without replacing thermal generation with non-emitting resources. Energy efficiency, demand response, and aggregation and management of flexible loads will help shave load and reduce peak energy needs; but no combination of these resources is sufficient to offset all the thermal capacity currently serving our customers and to meet anticipated load growth. Again, these findings are consistent with other studies of long-term decarbonization, which generally all suggest a large increase in non-emitting generation is required to meet emission reduction goals.

However, Staff's question asks about modifications in PGE's decarbonization strategy that go beyond updates to procurement volumes mentioned above. This question is unanswerable, as PGE does not have the foresight to know when, where, and why conditions will change to warrant a different strategy; if PGE knew where these junctures sat, it would already have changed its plan to address them. PGE, the Commission, and stakeholders can re-evaluate PGE's strategy when the next CEP/IRP is filed. In the interim, PGE proposes to take the no-regrets near term actions proposed in the Action Plan and we will continue to look both internally (e.g., changes in operational requirements) and externally (e.g., market redesign) to address challenges to affordability, reliability, and decarbonization.

> *What information will the Company use to determine whether a change in course may be warranted? Will the Company adjust its strategy based only on the progress of procurement, or will PGE examine additional data, like actual GHG emissions, power costs, load forecasts, and load forecast uncertainties, as the Company executes its strategy?*

The company will have to acquire sufficient non-emitting generation to maintain system adequacy while reducing dependence on thermal generation to meet retail load. In its long-term planning processes, PGE already incorporates GHG emissions, power costs, load forecast uncertainties into its analysis. The Company expects to continue updating and incorporating this data going forward. Additionally, new data and information will inform future planning assumptions, including that which we learn through responses to our RFP. Our ability to acquire on a least-cost, least-risk basis, as well as any significant changes in technology cost or availability could modify PGE's preferred resource mix in the future.

Affordability for customers and system reliability remain PGE's priority as we decarbonize. If risks to system reliability or unsustainable rate pressures for customers materialize, PGE will invite further discussion and direction from the Commission regarding the cost and reliability pauses referenced in HB 2021.

> *Under what circumstances could each of PGE's planned actions result in poor outcomes for customers?*

PGE's customers have routinely expressed their preference for an energy system that is reliable, affordable, and increasingly decarbonized. Accordingly, any action that reduces any of those three main components could be considered a poor outcome to customers. PGE sees very few opportunities for unilateral actions the Company can take to improve one or more components without negatively affecting another. For example, incremental generation resources cost money, which while increasing decarbonization and reliability, reduces affordability. However, the opportunities to partner with our customers on flexible grid solutions, including demand response, energy efficiency, managed vehicle charging, solar paired with batteries, and distributed standby generation can help reduce our customers' overall energy expenditures, lower GHG emissions, and provide needed flexibility and capacity to the grid. That is why these resources factor more prominently in this CEP/IRP and proposed Action Plan than in years past.

In this CEP/IRP, PGE did not model any evaluation of reducing system reliability, as the Company believed its long-term plan should ensure a consistent approach to resource adequacy. As a side analysis PGE did consider some variations in likelihood the company was able to meet 2030 emission reduction targets. This analysis did not influence the Action Plan, as the Commission directed PGE to create a plan that achieved emission targets under expected average conditions.[4] Accordingly, PGE created a plan that achieved reliability and emission reduction targets at the lowest expected costs. To determine the economic feasibility of this plan, a more salient question to both PGE and its customers would be to ask what potential rate impacts customers would accept to have a reliable and decarbonized system. PGE has been transparent in providing all projected cost information and is willing to continue working with Staff and stakeholders to assess that challenge.

Finally, while it is impossible to create a portfolio that is devoid of risk, PGE's planned actions are designed to be robust to a wide range of future circumstances while balancing the inherent tradeoffs between key outcomes for customers. There is substantial uncertainty inherent in forecasting of energy prices, resource costs, supply chains, need, weather, etc. That is why portfolio analysis is conducted across many future conditions to capture the effects of a wide range of potential future outcomes. PGE's Action Plan represents the best combination of cost, risk, community benefits and emission reductions, as determined by the

[4] See Commission Order No. 22-446: https://apps.puc.state.or.us/orders/2022ords/22-446.pdf

insights gained through portfolio analysis and the construction of the Preferred Portfolio. The goal is to provide the best possible combination of outcomes for customers across the range of these areas while balancing the tradeoffs between them.

Did PGE consider but exclude any actions because of their potential for adverse impacts to customers under one or more future scenarios?

Yes, PGE considered many actions that were eventually excluded from the Preferred Portfolio due to their potential for adverse impacts to customers. As mentioned above, portfolio analysis in the CEP/IRP was designed to consider which actions should be taken to provide maximum benefit to customers while meeting decarbonization requirements and maintaining a reliable system. This was done by designing groups of portfolios to test outcomes regarding key planning questions. PGE considered both faster and slower rates of decarbonization and found that neither could provide a better balance of the tradeoffs between cost and GHG-reductions than a linear glidepath. PGE considered including additional quantities of EE above and beyond what ETO forecasted as cost-effective, however, the Company elected to exclude them in the Preferred Portfolio due to their near-term cost impacts and uncertainty regarding how recent historic increases in federal, state, and local funding for energy efficiency in our service territory may shift the market and lead to new opportunities for our customers to access these energy saving opportunities at lower cost. PGE considered not pursuing transmission expansion and upgrades, but portfolio analysis strongly suggested this would increase both costs and risk as well as the reliance on transmission capacity beyond what is forecasted to be currently available. The consideration of lower quantities of CBRE acquisitions was also evaluated but found to increase cost and risk while also decreasing community benefits. PGE will continue to work with Staff and stakeholders to determine the most appropriate questions in long-term planning and will seek to design its portfolio analysis to answer them.

Chapter 2. Transmission

2.1 Comprehensive transmission comments

OPUC Staff submitted multiple near-term transmission questions and comments regarding South of Allston (SoA) congestion relief and Bethel-Round Butte upgrades. Staff is concerned that these two near-term Action Plan items are not supported by analysis.[5]

Specific to SoA congestion relief, Staff writes that PGE "has not provided very much analysis" to demonstrate that the benefits of the SoA upgrade outweigh the costs. They note that the

[5] LC 80 Round One Comments of Staff at 32-34

CEP/IRP only compares this upgrade to a generic variable energy resource, and that this comparison is arbitrary given the generic nature of that resource. They ask "if and when" PGE can provide more specific cost/benefit analysis to determine what upgrades should be invested in and/or what alternatives should be pursued.

Staff asks if PGE has considered different approaches to relieving SoA congestion, including solutions like batteries and/or multiple option solutions, and interpret the congestion relief Action Plan item to be "inclusive of a range of possible solutions." Staff also asks if the SoA congestion relief is feasible by 2030, and if not, what alternatives exist. Lastly, Staff asks if the SoA upgrade is driven partly due to load-service needs (as opposed to renewable procurement), and if yes, how the costs and benefits of the upgrade changed with the Addendum load growth assumptions.

Related to the Bethel-Round Butte Action Plan item, Staff notes that they are unclear on the amount of transmission (in MW) this upgrade would provide and are unclear on its costs. They are concerned that this transmission option has not been incorporated into portfolio analysis, and that PGE has not "provided the information needed to confirm that the costs of this type of investment is supported by PGE's analysis." Staff also asks if the Preferred Portfolio would change if the costs and benefits of this option were included in modeling. They reiterate that like SoA congestion relief they need more cost/benefit analysis, including analysis on thermal operations and GHG emissions, to "determine the investment reasonable."

OPUC Staff asks PGE to explain the CEP/IRP long-term transmission strategy, noting that the Action Plan does not provide insights into how regional transmission resources will be acquired. They ask for PGE to improve transmission modeling for future planning work, and to explain how the transmission strategy protects against risks, what those risks are, and how PGE will use transmission rights excess to load service to benefit customers.[6]

Regarding regional transmission, Staff would like to know when PGE will know if the Wyoming and Desert SW transmission proxies are feasible within the timeline of the Preferred Portfolio (553 MW of resource acquired by 2029, 800 MW by 2030). If they prove to be infeasible, Staff asks what alternative resources and/or transmission strategy exists. Staff is also concerned that the 2030 reliance on Wyoming and Desert SW transmission increased from 255 MW in the filed IRP to 800 MW in the Addendum, and notes that PGE has not addressed the risk "that it may have severely underestimated or overestimated future transmission needs within the plans."

NewSun Energy and Energy Advocates also raised concern regarding the transmission proxy development timeline. NewSun states that if PGE is unable to secure transmission rights or

[6] LC 80 Round One Comments of Staff at 30-31, 34-36

partnerships on existing projects that a new transmission build could take "at a minimum" 10 years to construct. They are concerned that reliance on the transmission proxies could lead to under-procurement of other resources should the proxy be unavailable.[7] Energy Advocates notes that proxy transmission to Wyoming and The Desert SW appears in the Preferred Portfolio as early as 2029, which is at odds to PGE's statement that "…new significant transmission projects can take 15-20 years to develop..."[8]

Lastly, Staff notes that the transmission strategy includes around 15,000 MW of transmission rights in 2040 while PGE's peak load reaches roughly 6,000 MW. They state that this strategy is "not sustainable" and prioritizes avoiding transmission-related curtailments over "all other cost and risk considerations." Staff asks how those levels of transmission rights will benefit customers, and what other strategies PGE could examine to reduce costs to customers and to avoid "over-constraining BPA's transmission inventory." Staff notes other strategies exist, including using short term firm or non-firm transmission, sharing transmission rights of existing resources, joining an RTO, securing transmission to less constrained points, and limiting rights "…across constrained paths based on what is needed for load service…" They suggest PGE explore, potentially via zonal dispatch modeling, alternative transmission strategies in the next CEP/IRP and identify the costs, risks, emissions, and community impacts of those strategies.

AWEC finds PGE's transmission modeling to be generic in nature and thus unsupportive of investment plans.[9] They note that the resources unlocked by SoA congestion relief have transmission paths that should be differentiated in the analysis and are skeptical that SoA congestion relief would benefit all Northwest proxy resources like solar in McMinnville or Christmas Valley. AWEC also finds PGE's transmission Action Plan items to be unactionable, noting that the amount of transmission selected by the CEP/IRP did not increase in the Addendum despite the increased resource need. They are unsure if Commission acknowledgment of the Action Plan would allow further study of transmission or transmission resource acquisitions.[10]

RNW encourages PGE to perform a more detailed examination of transmission options, in part due to the rapid development schedule in the CEP/IRP, and in part to improve offshore wind analysis.[11] They find that PGE's transmission modeling is overly generic and note that the specific upgrades available (SoA and Bethel to Round Butte) favor resource development in those areas, and that PGE has not demonstrated which transmission projects are best since that involves determining which geographic areas or technologies are of highest resource

[7] LC 80 Round One Comments of NewSun at 6-7.
[8] LC 80 Round One Comments of Energy Advocates at 10.
[9] LC 80 Round One Comments of AWEC at 9-10.
[10] LC 80 Round One Comments of AWEC at 11-12
[11] LC 80 Round One Comments of RNW at 30-31.

value.[12] They state that "Oregon offshore wind is a viable alternative to SoA and Bethel to Round Butte because its energy can be delivered to Portland without these specific transmission upgrades," and that based on a NorthernGrid study that offshore wind would alleviate SoA congestion.[13] Finally, they ask for PGE to consider merchant transmission projects in the CEP/IRP and to actively consider non-wires solutions for addressing transmission congestion.

Energy Advocates would like a transmission workshop held to discuss the details of the CEP/IRP transmission assumptions, with a focus on SoA congestion relief and the Wyoming and Desert SW proxies. They state that the transmission information provided in the CEP/IRP goes beyond what was discussed during the development of the CEP/IRP, and that the workshop could help stakeholders better understand the transmission options.[14] NewSun Energy recommends that the Oregon PUC hold a transmission workshop on upgrades to the BPA system. They are concerned that the transmission service requests (TSRs) pointing at PGE are no longer available. They also ask for a different methodology to determine the availability of firm versus condition firm transmission rather than assuming that confirmed TSRs are firm and those in study are conditional firm. Lastly, NewSun is concerned that the timeline for BPA transmission upgrades in the CEP/IRP is unrealistically quick.[15]

PGE's response

PGE appreciates stakeholder input noted above and the opportunity to explain how the transmission resources in the Action Plan fit into its wider transmission strategy as the company moves towards the emission reduction targets established in HB 2021. Finding a means to increase capacity over the South of Allston flowgate and the upgrading of the Bethel-Round Butte line from 230 kV to 500 kV are critical to acquire sufficient generation. Additionally, the company is continuing its work planning for cost effective, safe, and reliable load service by advancing nearly twenty transmission projects needed to bolster system reliability and bring incremental transmission capacity to and through PGE's service territory to serve growing loads. Projects currently included in PGE's local Transmission Plan span both projects that enhance regional transmission reliability and expand interface capacity with BPA, as well as projects that are designed to meet high concentrations of new load and enhance reliability on specific parts of PGE's system. These specific projects are listed below in **Table 1**.

[12] LC 80 Round One Comments of RNW at 40-41
[13] LC 80 Round One Comments of RNW at 41 & 43
[14] LC 80 Round One Comments of Energy Advocates at 8.
[15] LC 80 Round One Comments of NewSun at 7-8.

Table 1. Summary of regional enhancement projects

Title	Purpose/scope
Harborton Reliability	Reconfigure the system to reduce exposure and provide a stronger source to Northwest Portland 230 and 115 kV systems. Expected completion 2026.
Horizon-Keeler BPA #2 230kV	Accommodate load growth in Hillsboro by constructing a new bay at BPA's Keeler Substation. Expected completion 2024.
Willamette Valley Resiliency	Strengthen and increase the resiliency of PGE's system in the Central portion of PGE's territory, north of the Salem region. Expected completion 2028.
Pearl/Sherwood 230kV Reinforcement	Mitigate the overloading of the McLoughlin-Pearl BPA-Sherwood 230 kV line caused by the loss of the Pearl BPA-Sherwood 230 kV line. Expected completion 2026.
Hillsboro Reliability	Significant upgrades to prepare for load growth in the Hillsboro area. Expected completion 2027.
Horizon Keeler BPA #1 230 kV Reinforcement	Mitigate overloads seen on the Horizon-Keeler BPA #1 230 kV line due to Hillsboro-area load growth. Expected completion 2027.
Murrayhill-Sherwood #1 and 2 230 kV Reconductor	Mitigate overloads caused by the loss of other 500 and 230 kV sources during south-to-north flow conditions in the Beaverton/Hillsboro area. Expected completion 2027.
Murrayhill-St. Marys #2	Mitigate overloads caused by the loss of other 500 and 230 kV sources during south-to-north flow conditions in the Beaverton/Hillsboro area. Expected completion 2027.

Additionally, PGE has identified projects that are included in the OATT Attachment K Local Transmission Plan and are designed to enhance local system reliability, displayed below in **Table 2**:

Table 2. Summary of local system reliability projects

Reedville Substation Rebuild	Groveland Substation Project
Memorial Substation Project	Glencullen Rebuild & Cedar Hills Breaker Project
Tonquin Substation Project	SE Portland Conversion Project Holgate Substation
Kaster Substation Project	Mt Pleasant Substation Project
Redland Substation Project	Scholls Ferry Substation Project

Further, PGE is also collaboratively investigating with its regional peers how transmission and resource planning processes should be reformed to create an actionable regional transmission plan the evaluates the regional transmission system using a 'one-utility' approach.

South of Allston

PGE has been experiencing increasing load growth across our territory, with a high concentration in the Portland Metro area that includes Hillsboro. To serve that load PGE needs to increase the transfer capability to and through PGE's system to discrete load service areas. Adding capacity to the South of Allston flowgate does this. An upgrade to the South of Allston flowgate that brings incremental transfer capability to and through PGE's system also benefits customers through supporting reliability in the Portland and Hillsboro area.

There is not a location on the BPA system, or beyond, to site generation that does not have an impact on South of Allston flowgate. This is because of Power Transfer Distribution Factor (PTDF), which refers to the distribution of power flows on the networked transmission system. PTDF applies broadly across the regional transmission system. For PGE, because of the topology of the regional transmission system, there are effectively no locations within the western interconnection, whether inside BPA's footprint or beyond, where new incremental transmission service can be added that delivers to PGE that doesn't measurably impact flows on the South of Allston path. With South of Allston being fully subscribed, a transmission solution to bring incremental transmission capacity to South of Allston is necessary to enable incremental transmission service directed to PGE. Adding transmission capacity provides an opportunity to meet HB 2021 requirements. Additionally, studies are now demonstrating that upgrades to South of Allston are necessary to deliver enough power to serve the northern part of PGE's service area, which includes Portland and Hillsboro. This means the company must increase the total transfer capability to serve requested load in Hillsboro/Portland area.

The recently announced BPA projects from their TSEPs help increase deliverability to PGE's general service territory, but it is not possible to discern exactly how much capacity BPA's projects will bring that directly benefit PGE customers with the currently available information. When this information becomes available, we will incorporate it into our models and ensure our plans are still the best for choices for customers.

PGE has not recently considered alternative methods to alleviate South of Allston congestion (such as batteries or non-wires alternatives) because the known constraint in the studies is hundreds of MWs and can last greater than 12 hours. Figure 66 in the filed CEP/IRP shows that the expected deficit in 2030 is more than 1,500 MW, and due to the volume and timing there simply is not an economically and operationally viable alternative today. PGE believes that if work began immediately on the South of Allston flowgate the increased capacity could be available by 2030.

Bethel-Round Butte

The Bethel-Round Butte component of the Action Plan aims to study optionality to develop a project that would upgrade the Bethel-Round Butte 230 kV line to 500 kV. The project would increase transmission capacity from resource-rich areas of central and southern Oregon to

PGE's system. The project also increasingly connects PGE's load service territory directly with the Northwest AC Intertie (NWACI), the 500 kV transmission system that connects Oregon and California. PGE is a co-owner of the NWACI along with BPA.

The Bethel-Round Butte line is part of the Cross Cascades South which is considered a WECC defined path. The Cross Cascades South Path is the same as BPA flowgate known as West of Cascades South (WOCS). The WOCS flowgate is currently known to be constrained and is viewed by some commenters in this docket as PGE's biggest obstacle to delivering new resources to company loads. Currently, the Bethel-Round Butte line is considered a de minimis component of the WOCS flowgate. An upgrade of the Bethel-Round Butte line will increase WOCS transfer capability for the purposes of serving PGE's system loads. It should be noted that due to the geographic location of the Bethel-Round Butte line, energy deliveries that use new incremental line capacity could allow PGE to avoid the constraints of multiple BPA flowgates that exist near the border between Oregon and Washington.

Together with the Confederated Tribes of Warm Springs (CTWS), an application has been submitted to the US Department of Energy (USDOE) seeking up to $250 million dollars in grant funds under the USDOE's Grid Resilience and Innovation Partnerships Program. If the grant application is successful, PGE and the CTWS will partner on the development of the project. Along with PGE's increased access to resources and energy markets, the project would provide the CTWS economic development opportunities that otherwise would not exist. PGE currently lacks the detail that parties are requesting as the Company has not yet started in earnest studying the project. There are many variables still to be determined. PGE plans on conducting the analysis over the next few months.

Transmission in CEP/IRP portfolio analysis

PGE appreciates the feedback on the need for improved transmission analysis as part of future planning processes. For the need for greater granularity on paths that would alleviate SoA congestion and increase transfer capability over the Bethel-Round Butte path, we note that the Action Plan requested that both options should be further explored via power flow studies and economic analysis to meet the portfolio need identified in the CEP/IRP. PGE plans on conducting this analysis in the coming months, and we expect that this additional analysis can provide more granular detail on the potential capabilities of transmission upgrades and the more precise cost/benefit tradeoffs.

Regarding the proxy Wyoming and Desert Southwest transmission options being available too quickly, PGE agrees with that statement if the assumption is that any new rights introduced into the portfolio are based on beginning a new resource build today. PGE's Action Plan assumes that the company can and will explore all options to add incremental rights, including acquisition of rights on existing regional systems, and/or potential participation in new inter-regional transmission builds that are already underway and scheduled to come online before 2029. PGE stresses that these two options are proxy representations and that other transmission options may be explored as well.

It is also worth noting that the portfolio selections, both in the Action Plan window and later in time, are proxy-based, are intended to solve system-based need to ensure operational reliability. For example, Staff notes that 15,000 MW of incremental transmission rights in 2040 seems like an unsustainable number, however as part of WRAP compliance obligations, PGE is expected in the day of operations to have 100 percent of energy delivered to load on firm transmission. Reliance on non-firm leaves PGE at risk of increased curtailment, increased loss of load probability, and sanctions for non-compliance. When a transmission loading relief (TLR) is issued (curtailment order), non-firm transmission is the first to be curtailed, consistent with NERC e-tag priority, to alleviate congestion on the flowgate. At the same time, BPA stops all sales of transmission across that flowgate. For the South of Allston flowgate, there is not a generation location on the BPA system that has a non *de minimis* impact on the South of Allston flowgate, meaning the only alternative PGE must resupply the curtailed energy is from on-system generation. TLR events are most likely to occur during high load times, when all on-system generation is being dispatched to serve load with little to no capability to backfill non-firm curtailments and puts PGE at greater risk of having to shed load. Also, there are limited quantities of firm ATC in the short-term time horizons. Conditional firm products have priority access to short-term ATC, meaning conditional firm transmission service reservations (TSRs) are firmed up with any short-term ATC, given the volumes of conditional firm service, BPA releases limited amounts ATC in the short-term market.

Regarding the comments on offshore wind generation, and its impact on South of Allston transmission, PGE agrees that in general, import of power in the Southern Oregon area appears to have a minimal impact on the South of Allston flowgate. The BPA Power Transfer Distribution Factor calculator (displayed below in **Figure 1**) estimates that for every 100 MW injected at Gold Beach (an offshore wind proxy location), South of Allston would experience 7.5 MW of additional congestion, which may be considered a *de minimis* impact. BPA notes that the PTDF calculator on their website should be used for indicative purposes only and that all requests for long-term firm transmission capacity must be studied. It is worth noting that this calculator does not yet include the modifications necessary to account for the new BPA flowgates that are currently being implemented and impact PGE, including the North of Pearl flowgate (NOPE) and the North of Grizzly flowgate (NOG). NOPE is a west-to-east cutplane flowgate located between Sherwood and Wilsonville and significantly impacts PGE's ability to delivery power to Portland and Hillsboro. NOG is a new flowgate that will be implemented on the NWACI north of PGE's Bethel-Round Butte line. The successful development of a Bethel-Round Butte upgrade project could allow PGE to avoid NOG impacts and the successful development of a South of Allston project could help mitigate impacts from the implementation of NOPE.

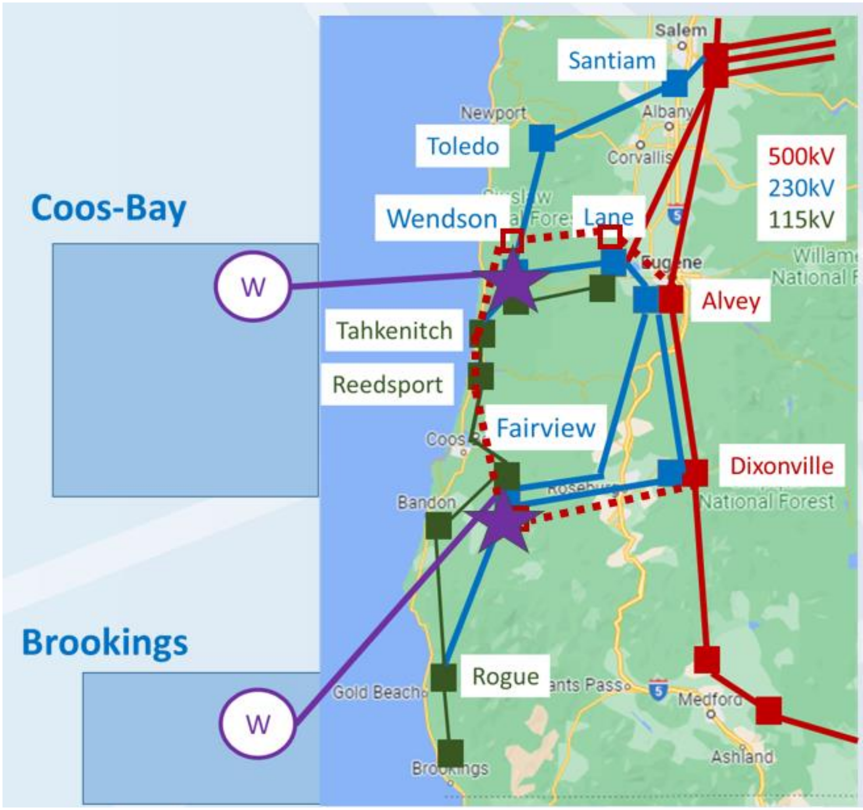
Figure 1. BPA Power Transfer Distribution Factor calculator

			Zone	kV	Owner Name
Evaluated Source:	GOLDBEACH115		Western Oregon	115	Bonneville Power Admin
Evaluated Sink:			PAC:PTLD	230	PacifiCorp - West
Request MW:	100				
Posted 6/1/23					
Sub Grid Constrained Area:		PORTLAND AREA			
PTDF #:	40475	45301			
Flowgate	**Source**	**Sink**	**% Impact**	**MW Impact**	**Result**
CROSS CASCADES NORTH E>W	-0.1955	-0.2642	6.9%	6.9	Potential LTF
CROSS CASCADES SOUTH E>W	-0.5196	-0.6736	15.4%	15.4	Study for CFS
NORTH OF HANFORD N>S	-0.5992	-0.5277	-7.2%	0.0	Potential LTF
RAVER-PAUL N>S	-0.1271	-0.1739	4.7%	4.7	Potential LTF
SOUTH OF ALLSTON N>S	-0.2018	-0.2757	7.4%	7.4	Potential LTF
WEST OF JOHN DAY E>W	-0.0697	-0.2598	19.0%	19.0	Potential LTF
WEST OF SLATT E>W	-0.1906	-0.1355	-5.5%	0.0	Potential LTF
WEST OF LOWER MONUMENTAL E>W	-0.0586	-0.0580	-0.1%	0.0	Potential LTF
SOUTH OF CUSTER N>S	-0.0022	-0.0059	0.4%	0.4	Potential LTF
NORTH OF ECHO LAKE S>N	0.0441	0.0464	-0.2%	0.0	Potential LTF
WEST OF MCNARY E>W	-0.1345	-0.1259	-0.9%	0.0	Potential LTF
WEST OF HATWAI E>W	0.0551	0.0418	1.3%	1.3	Potential LTF
NORTH OF GRIZZLY N>S	-0.2119	-0.0022	-21.0%	0.0	Potential LTF
0.#####	Indicates that impact may be considered de minimis.				

Per the ongoing NorthernGrid Economic Study Request that examined offshore wind impacts on the regional transmission system, significant additional transmission investments would be required to accommodate any large injection of offshore wind generation. The study identified that for 3 GW of new wind, hundreds of miles of additional 500 kV transmission lines would need to be built. Much of the required right-of-way would pass through the sensitive Rogue River Valley and other sensitive and scenic coastal areas. The expected cost of this required transmission infrastructure is significantly higher than the contemplated PGE transmission projects. It is important to remember that the economic study was for economic dispatch evaluation purposes only and did not contemplate the full scope of analysis necessary to evaluate interconnection and delivery to specific load centers. It is expected that interconnection and transmission service delivery analysis studies would identify significant additional costly transmission upgrades.

Additionally, the NorthernGrid study utilized a 2030 delivery date for the projects, which would not meet PGE's needs and is likely not feasible. The project would also primarily require BPA and PacifiCorp to fund and construct the upgrades, with significant portions needing to be located in new or expanded rights-of-way. PGE will have little control or influence of project timelines. In addition to transmission upgrades by BPA and PacifiCorp, land-based coastal infrastructure necessary to deploy offshore wind will need to be developed. PGE understands that there is not sufficient port or highway infrastructure currently in place in Oregon necessary to deliver, assemble, and make ready offshore wind equipment for deployment. **Figure 2** displays the interconnection upgrades necessary for the development of offshore wind.

Figure 2. Necessary interconnection upgrades for offshore wind



Regarding the suggestion of a potential transmission-specific workshop, PGE is not convinced that is the most productive use of time. The Company has spent substantial time in the IRP roundtable meeting series describing transmission planning, and we encourage any participants who missed those sessions to rewatch the videos available on our website as time allows. PGE periodically holds 'office hours' throughout the comment period, as opposed to additional workshops. We recommend bringing these questions to the office hours sessions. If these topics cannot be sufficiently addressed in that forum, the Company is committed to working with parties to determine how to address them. Earlier transmission focused workshops covered material at a rudimentary level and did not lead to any actionable changes in transmission planning or operations.

Regarding the comment that the analysis is overly generic, the transmission analysis in the PGE IRP focuses on transmission paths that are (1) impactful to PGE's ability to import generation (2) known to have existing congestion and (3) projected to experience increasing congestion due to changing generation and load patterns. The overall transmission system is networked, and generation impacts at one location affect flows across the network. As additional generation is constructed in the Western Interconnect, PGE will continue to assess how these changing generation patterns impact potential transmission bottlenecks and identify necessary transmission investments accordingly.

2.2 Conditional firm transmission modeling

RNW, via a report written by Grid Strategies, again asks PGE to rethink the modeling of conditional Firm 200hr transmission and that a more detailed curtailment analysis could lead to "innovative solutions to transmission congestion."[16] They provide an updated version of their conditional firm study that they submitted with their Initial Comments.[17] They find that zero hours of curtailment should be used for modeling conditional firm 200hr transmission in the adequacy model. However, arriving at that result required them to assume that curtailments are reduced via a 4-hour 2,400 MW battery. The 4-hour 2,400 MW battery represents "the installed storage capacity between PGE and PacifiCorp West."[18]

Grid Strategies responded to the comments PGE provided in its Initial Comment Response. They agree with PGE's comment that not all resources should use conditional firm transmission due to "uncertainty about the location and quantity of the regional expansion of renewable and storage resources", but then restates that BPA has never curtailed conditional firm transmission and again finds that zero hours of curtailment should be modeled for conditional firm transmission.[19] They do not think studying the South of Alston transmission path is necessary and still think the West of Cascade South path is PGE's key transmission constraint point. Grid Strategies agrees that a power flow study is the best modeling approach and suggests that PGE conduct one, that insufficient data are available for a N-1 analysis, that incorporating load growth into the analysis is unnecessary, and that accounting for renewables built by other Northwest utilities (outside of PacifiCorp and PGE) is unnecessary.[20]

PGE's response

PGE appreciates the work that both RNW and Grid Strategies have done to contribute to the transmission picture in Oregon. While additional analysis can help to clarify the overall picture, PGE has concerns with the methodology employed to determine that zero hours of curtailment for BPA Conditional Firm products should be the base case for future analysis, and we caution against extrapolating any near-term decisions based on the analysis.

Primarily, the study relied on the assumption that there will be 2,400 MW worth of 4-hour batteries installed that could offset the need for curtailment by shifting transmission in a way that would alleviate congestion. PGE notes that this would likely be a significant resource addition effort alone. Additionally, the study assumed that South of Allston would be

[16] LC 80 Round One Comments of RNW at 30-31
[17] LC 80 Round One Comments of RNW at Attachment D
[18] LC 80 Round One Comments of RNW at Attachment D
[19] LC 80 Round One Comments of RNW at Attachment D
[20] LC 80 Round One Comments of RNW at Attachment D

upgraded, meaning that the zero-curtailment case would hold only if PGE were to pursue at least one of the actions listed in the 2023 CEP/IRP Action Plan. Finally, the study notes that "newer technologies and practices… can be used to respond to system contingencies." PGE agrees that future technology and process innovation will help make transmission planning nimbler and more precise, but that future state cannot be the basis of near-term modeling that could impact PGE's operational window.

PGE does not disagree with Grid Strategies' findings necessarily over a 20-year time horizon and under the specific conditions put forward (South of Allston upgrade in place, 2,400 MW of incremental 4-hour battery, and new technologies). However, we note the risk of making operational decisions (such as assuming zero curtailment for the purposes of actual resource acquisition) based on the study put forward. PGE looks forward to continued collaboration with staff and stakeholders to assess the right operational modeling needs as we work to maintain reliability and progress toward the decarbonization targets.

PGE is also concerned about Grid Strategies' choice of load growth assumptions. For context, the PGE Corporate Forecasting expects 1-in-10 loads to increase from 4,456 MW in 2023, to 5,166 MW in 2030, to 6,362 MW in 2040. If the Grid Strategies analysis failed to consider these (very reasonable) increases in forecasted load, it would miss significant impact that this additional load has on regional transmission paths, including SOA and WOCS. It should be noted that PGE's load during the 2021 heat dome event exceeded 4500MW on two occasions in August of 2023. PGE believes the analysis should consider WECC-wide load and generations; simply looking at PGE and PAC does not appropriately estimate all the changes in flows we are seeing across BPA's network. PGE does not believe the study provides sufficient evidence that the capacity contribution should be the same for LTF and CF transmission.

2.3 Proxy Transmission Cost

Energy Advocates would like more information on the costs used for the proxy transmission projects to Wyoming and the Desert Southwest. Specifically, they would like to know if the prices from the 2018 report have been updated to reflect current prices, including if the prices have been adjusted for inflation, and if not, if PGE is taking potentially higher prices into consideration.[21] NewSun Energy also has concerns regarding the cost of the generic proxy resources, noting that PGE has not explained how they were developed and questions if they are reflective of costs found on the market. They cite the study PGE used to develop

[21] LC 80 Round One Comments of Energy Advocates at 9-10

costs that notes that transmission costs can be "substantially higher if substations are needed" and if right-of-way costs are higher.[22]

PGE's response

PGE has not done additional work on the transmission proxy costs since filing the CEP/IRP. Rather, the company continues to rely on the 2018 report "Relative Costs of Transporting Electrical Chemical Energy" to form the basis of the transmission proxy costs in the CEP/IRP.[23] To formulate the transmission proxy costs, the costs outlined in the study are adjusted for inflation using PGE's long-term inflation rate available at the time of the analysis.

As explained previously, PGE developed the cost assumptions by relying on the study cited above, where PGE converted the costs associated with a 500 kV single circuit transmission line expressed in a $/MW-mile metric. That cost, and the estimated distance of the proxy transmission paths, form the basis for the capital costs for the transmission proxies. PGE's historical O&M costs associated with our existing transmission portfolio are extrapolated and included as well. PGE's historical O&M costs associated with our existing transmission portfolio are extrapolated and included as well. The prices do not incorporate any further adjustments as the costs are intended to reflect a generic proxy resource. Market transmission costs can vary depending on factors like terrain, environmental considerations, right-of-way costs, substation costs, and so on. These nuances were not intended to be captured in this high-level, directional analysis. PGE notes too that increases to these cost estimates would only affect projections of future costs and would not likely change resource buildout choices.

2.4 Additional transmission options

Grid United suggests that the two proxy transmission expansion resources modeled in the CEP/IRP do not capture the full suite of interregional benefits PGE could capture through new transmission to other organized markets. They request that PGE include an interregional proxy resource that would provide additional benefits in additional analysis as part of the 2023 IRP Update or a future IRP.[24]

[22] LC 80 Round One Comments of NewSun at 6-7
[23] Saadi, Fadl H, et al. "Relative Costs of Transporting Electrical Chemical Energy." Energy & Environmental Science, Energy & Environmental Science, no. 3, 29 Jan. 2018, pp. 469–475.
[24] LC 80 Round 1 Comments of Grid United at 4

PGE's response

PGE agrees that including more proxy transmission resources would be beneficial and will consider developing interregional transmission options as we determine next steps for improving our transmission modeling going forward.

Chapter 3. Additional energy efficiency

3.1 Action Plan

Staff, CUB, and Energy Advocates recommend the inclusion of the ~50 MWa of additional energy efficiency (EE) that reduced long term cost and risk as shown within portfolio analysis.[25,26,27] Staff also noted that based on PGE's response, they believe that the procurement risk of EE is smaller and more quantifiable than procurement risks of other resources in the Preferred Portfolio, pointing to ETO's historical record of and ongoing discussion with ETO, and noting the relative size of the risk across transmission, storage, and EE. Staff also asked PGE to provide an update on the ongoing collaboration with ETO to procure the additional EE by 2030.[28]

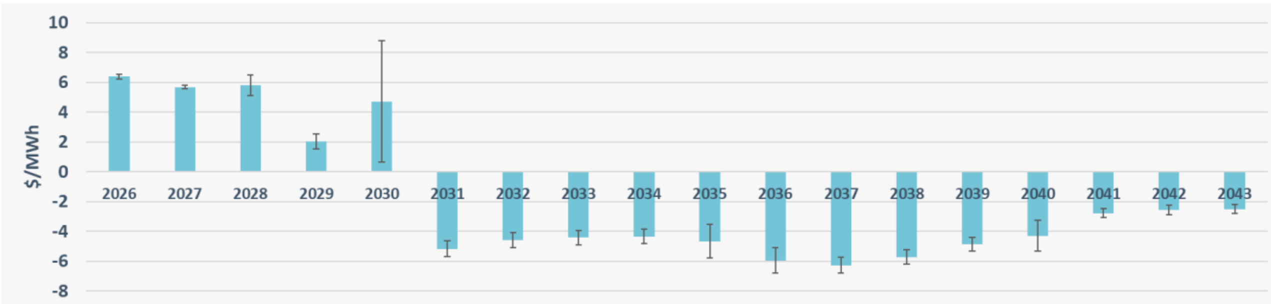
PGE's response

As shown in portfolio analysis, the additional ~50 MWa of EE above and beyond what is forecasted by ETO as cost-effective (based on previous avoided costs) compares favorably to other supply-side resource options that are transmission constrained. While PGE's proposed Action Plan includes the procurement of all cost-effective energy efficiency that is forecasted by ETO, PGE elected not to commit to the near-term rate increases that are associated with the additional increment of EE in the proposed Action Plan. This is because PGE believes that the level of new federal, state, and local resources being directed in support of energy efficiency is truly historic and dramatically changes the procurement options for energy efficiency. There may be less costly options emerging for our customers to access the additional energy efficiency than procuring it through rates. To further illustrate the rate pressure impact, PGE has compared the Preferred Portfolio developed as part of these Reply Comments with and without the additional EE.[29] Consistent with prior findings, when available the model selects a portion of the additional EE available ~50 MWa and it reduces

[25] LC 80 Round 1 Comments of Staff at 29
[26] LC 80 Round 1 Comments of CUB at 2
[27] LC 80 Round 1 Comments of Energy Advocates at pp. 5-7
[28] LC 80 Round 1 Comments of Staff at 29
[29] **Section 6.2.4** details the Preferred Portfolio developed as part of PGE's Round 1 Comment response.

the NPVRR of the portfolio by $532 million across the planning horizon.[30] This decrease in long-term cost should be compared against the increase in yearly rate pressure, which is displayed in **Figure 3**.

Figure 3. Price impact of the Preferred Portfolio with and without additonal EE[31]



Never-before-seen levels of new federal funding for energy efficiency, enabled through the IRA and IIJA, may fundamentally alter the market landscape for EE and demand response opportunities for our customers. At the same time, there are significant new local and state resources, including the Portland Clean Energy Fund (PCEF) and DEQ's Community Climate Investments fund (CCI), that will bring additional energy efficiency opportunities to customers in our service territory. On its own, PCEF plans to spend $150 million/year for the next five years just within the City of Portland, which is a greater investment than ETO spends annually on conservation within PGE's service territory.

The additional ~50 MWa increment of energy efficiency mentioned in our plan is not modeled to be added until 2026.[32] Between now and then PGE anticipates greater clarity on many uncertainties germane to the expansion of EE in our service territory through these other investments. Further, the ~50 MWa resource labeled as Energy Efficiency represents an opportunity to acquire related DER measures where co-deployment can save money in relation to independent procurement actions. This fact highlights a limitation of the current capacity expansion analysis yet opens an opportunity which should be thoroughly discussed with stakeholders and the Commission. Examples of measures which carry both EE and flexible load values include insulation, smart thermostats, water heating and space heating. PGE views this fact along with coordination of federal funding as an opportunity to procure both energy efficiency and more dynamic flexible load resources. Co-deployed measures which procure additional flexibility and dynamic capabilities grant PGE operational capabilities which solely procuring EE would not. Although co-deployment would increase the dollars necessary to acquire installation of the measure the coordinated approach would

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[30] The exact quantity selected is (and has been) 53 MWa; PGE uses '~50 MWa' in this document as that value has been used in earlier comments and in public meetings.
[31] A positive (negative) value suggests a higher (lower) yearly cost per MWh of the portfolio with the additional EE
[32] An initial date of 2026 in the CEP/IRP represents a resource that is procured before December 31st, 2025

save customer dollars overall. In the recent past through our demand response programs such as Smart Thermostats and our U.S.DOE grant project within the Smart Grid Testbed known as the SALMON Project, ETO and PGE have learned that energy efficiency and flex load can be co-deployed. These facts and lessons learned regarding the co-benefits of co-deployment points to a pathway by which the expenditure to procure the 50 MWa identified in the IRP can provide a host of benefits to customers beyond EE, and when coordinated across funding streams and measure types each dollar used to acquire the greatest customer and system benefit.

To this end we request the Commission grant the opportunity to all DSM procurement entities to coordinate both how and what is procured through which entities. This should magnify the effects of this rare funding opportunity but also acquire the greatest benefit at the lowest overall cost than if each entity operated independently. We recognize that this process adjustment may affect the Energy Trust two-year budgeting process. Later this year the Energy Trust is charged with delivering a two-year budget to the Commission, its Board, and funding utilities. PGE requests that the Commission be flexible regarding the delivery of Energy Trust two-year budget to create time for all entities to come together to work collaboratively to develop a proposal to acquire the necessary energy efficiency and other benefits.

Over the next 12-24 months, the scale of new energy efficiency investments in our service territory from federal, state, and local sources combined will become more readily apparent, and that anticipated energy efficiency resource will be included in the next round of IRP modeling. In other words, some, if not all, of the additional 50 MWa of energy efficiency that portfolio modeling shows today to be beneficial to our customers post 2026 may come online in our service territory through mechanisms that are neither procured by PGE nor paid for in rates by our customers.

We are also observing promising technological advancements by data centers and the semi-conductor industry toward deeper energy efficiency. For all these reasons, we chose not to include the additional 50 MWa of additional energy efficiency in our proposed short term Action Plan as this issue can be revisited, with the benefit of clarity on these other funding mechanisms and technology evolution, in the next IRP. In the meantime, PGE is coordinating closely with ODOE, PCEF, DEQ, ETO, municipalities, and other entities to bring as many of these dollars to our service territory as we can to help alleviate rate pressure for our customers and grant our customers greater access to energy savings opportunities. Because of the way energy efficiency is currently funded in Oregon the cost of the additional 50 MWa would hit our customers as a significant increase in rates in the near term, before the customer benefits of energy savings accrue. This is on top of the rate pressure we already anticipate from resource acquisition to meet emissions targets by 2030. Moreover, as we discuss in comments below, PGE agrees with Staff, CUB, and other stakeholders that a discussion of alternative funding mechanisms to address the issue of near-term rate pressure resulting from increasing spending on EE is needed. That discussion almost certainly takes place outside of LC 80 but will inform PGE's next IRP.

Affordability for our customers is our core priority as we transition to a cleaner energy system. Our decision to hold off on a commitment to additional energy efficiency acquisition through customer dollars until the totality of the additional funding sources and markets changes prompted by recent federal, state, and local policy are clarified should not be interpreted as weak support for energy efficiency as a resource important to decarbonization. PGE will continue to explore potential avenues to increase EE adoption through multiples channels while addressing near-term rate pressures.

3.2 Portfolio considerations

Energy Advocates asked for more details on why the long-term benefits highlighted within portfolio analysis are not sufficient basis for the inclusion of the additional EE. [33]

Staff noted that the OPUC has the tools to mitigate rate shocks to customers and advised PGE to work with the Commission to consider mechanisms to amortize or spread the cost of EE over multiple years. [34] CUB appreciated PGE's focus on near-term rate impact of EE but pushed back against considering utility rate base financing as a potential solution. However, CUB expressed an interest in discussing how securitization could be a solution to reduce the near-term rate burden. Specifically, CUB is interested in understanding if the amount is worth securitizing, the associated risks, its potential impact on PGE's credit rating and PGE's capital structure. [35]

Differing from CUB and Staff, the Energy Advocates argued that spreading costs over time through mechanisms such as financing or securitization impose higher costs on customers, due to the costs of financing. Specifically, they sought additional clarity on the policies that PGE believes must be amended to enable the inclusion of additional EE within PGE's Action Plan. [36]

PGE's response

IRP portfolio metrics of Cost, Variability, and Severity as well as community benefits and decarbonization were evaluated for each portfolio and displayed in the CEP data template. However, PGE also scrutinized portfolios that have different dimensions of cost and risk. For example, non-quantifiable procurement risks were used in the evaluation of the "Backloaded decline" decarbonization glidepath portfolio; despite showing lower Cost and Risk metrics,

[33] LC 80, Round 1 Comments of Energy Advocates at pp. 5-7
[34] LC 80, Round 1 Comments of Staff at 29
[35] LC 80 Round 1 Comments of CUB at 2
[36] LC 80 Round 1 Comments of Energy Advocates at pp. 5-7

PGE elected to not pursue this emission reduction glidepath because of the risk associated with procuring the required quantity of resources and the operational challenges of integrating them into the portfolio. Each of these risks are present in all portfolios to varying degrees but not quantitatively evaluated for all portfolios; nonetheless, they are both critical when determining the set of choices that make up the Preferred Portfolio. Similarly, when considering the additional energy efficiency portfolios PGE considered the unique implication of these resources on near term rates. While PGE did calculate and present the near-term cost impacts of all portfolios, the Company only presented this information for the EE portfolio as they were the only ones that were materially different across portfolios.

PGE is pleased to hear a willingness and ability of Staff to address the issue of near-term rate pressure resulting from increasing spending on EE. Addressing the comments by CUB, PGE believes this amount of spending on additional EE may be worth securitizing. PGE wouldn't want to securitize future costs if there is no guarantee that Energy Trust can perform the work, or if there are uncertainties in passing on the associated costs to customers. The process of securitization guarantees that we will bill the customer, guaranteeing debt payments over the life of the securitization. It would be credit negative if there was a potential for insufficient collection of payment in future years. Regarding the impact of securitization on the Company's capital structure and credit rates, PGE adds to the balance sheet with this debt, and adds cash on the asset side. In our disclosures we can note the capital structure with and without the securitized debt. If the financing order and state pledge, true up mechanism are strong, the rating agencies can view securitization as credit positive. Moreover, securitization doesn't address the emerging pathways now possible because of historic federal, state, and local resources for our customers to access energy efficiency, as discussed above. We believe that securitization, and other potential mechanisms for financing energy efficiency should be considered as part of a coordinated and integrated strategy to leveraging all of the now available resources to deliver energy efficiency to our service territory.

In response to the Energy Advocates highlighting customer savings from not amortizing EE, PGE notes that the costs savings associated with not financing or securitization EE are real but negatively impact near term affordability like other cases where loans are used to reduce the upfront expense. When comparing the near-term rate impact between the current Preferred Portfolio (revised below in **Section 6.2.4, Offshore wind in Preferred Portfolio**) and the same portfolio with access to EE, the portfolio with EE increases the yearly price by an annual average of 6 percent between 2024 and 2030.

3.3 Planning and execution

The Energy Advocates also noted a seemingly inconsistent approach to determining the quantity of EE that is cost-effective both through ETO's budget process and through the

CEP/IRP process. Additionally, the Energy Advocates noted the need for additional discussion on the topic of cost-effectiveness. [37]

PGE's response

Clarifying the nuance between EE targets set in the CEP/IRP and Energy Trust's budget setting process, PGE notes that the CEP/IRP provides directional insight based on proxy resource characteristics, which are used to set planning targets for EE, DR, and CBREs. For EE specifically, the proxy nature of the resource characteristics reflects planning assumptions made by both Energy Trust and PGE including estimated program costs and modeling approach.

Developing final program designs that maximize deployment of a specific measure/technology in the near-term, usually the following year or two, occurs during the ETO budgeting process. This is analogous to the DR procurement and the RFP process, where specific technologies and implementation details are decided downstream of the CEP/IRP process. Thus, while the CEP/IRP is the appropriate venue to determine the longer-term role of EE and its impact on system costs and risks, the ETO budget process is the appropriate venue to determine the final quantity of cost-effective, reliable, and feasible EE that will be procured for customers in the following year.

The difference between the targets set in the CEP/IRP and during the budget process, if any, would present as a risk of over or under procurement. Under procurement is commonly addressed by an increased reliance on existing thermal generation and market purchases, both of which can increase the risk that net variable power costs and/or PGE's emissions increase in that year.

The CEP/IRP targets and the ETO budget process are linked primarily through avoided costs, which are provided through regular yearly updates in UM 1893. A directional change in EE CEP/IRP will eventually be realized downstream through first updating avoided costs provided within UM 1893 and then ensuring the Energy Trust budget process has the appropriate resources to incorporate any change in direction. PGE notes that the CEP/IRP targets, while helpful, do not represent a necessary condition to changing EE procurement as long as both downstream process (updated avoided costs and the Energy Trust budget process) are completed.

Regarding the topic of cost-effectiveness, PGE notes that in the context of IRPs a resource is "cost-effective" if it is chosen within portfolio analysis (ROSE-E model), which optimizes for a least cost system. Thus, the ~50 MWa of additional EE evaluated in the CEP/IRP is "cost-effective" from a CEP/IRP perspective. Conversely, the remaining additional EE and the additional DR that were evaluated were not deemed cost-effective. This connotation of cost-

[37] LC 80, Round 1 Comments of Energy Advocates at pp. 5-7

effectiveness was also noted in comments by Staff.[38] Also note that the CEP/IRP notion of cost-effectiveness is independent of the method of procurement. IRP analysis aggregates ETO's forecasts to specific bundles based on levelized costs; while this approach is necessary for including many relatively small EE measures in IRP portfolio analysis, there are important differences between it and ETO's estimates of what it can procure at different price points.

However, outside the IRP, the term cost-effectiveness is referring to understanding if a resource is equal to or above 1 on a cost-effectiveness test. The cost-effectiveness test aims to mimic the dynamics within portfolio analysis with the added impact of certain non-energy benefits and the 10 percent cost reduction credit, as applicable. Cost-effectiveness tests attempt to mimic portfolio analysis by using avoided costs as their inputs, which are developed by studying the dynamics taking place within portfolio analysis. Discussing this connotation of cost-effectiveness within the IRP could be confusing because of the absence of a cost-effectiveness test and is not directly relevant because portfolio analysis determines which resource combination is optimal to ensure a reliable least cost system. To prevent conflation PGE elected to not use either connotation of the word in these discussions. PGE is open to discussing the use of these terms with stakeholders and address any confusion in their meaning.

3.4 Avoided costs within UM 1893

Staff noted concerns that the avoided costs provided by PGE using the established UM 1893 workbook do not adequately capture the value of EE as demonstrated within portfolio analysis.[39]

PGE's response

Avoided costs are developed by studying portfolio analysis and are inputs for cost-effectiveness tests among other applications. Avoided costs provided for EE follow established methods of estimating energy and capacity values as set by UM 1893. These methods have not evolved with the evolving landscape of the CEP/IRP. There are two dynamics that are not captured within the currently established methods of UM 1893:

- The UM 1893 method uses a single value for capacity usually based on the cost of capacity in the first year of deficiency, 2026 in this CEP/IRP. This approach does not capture two dynamics that have become more prominent in this IRP: the decreasing capacity contribution of the marginal resource that can provide capacity over the planning horizon, which impact the cost of capacity, and more importantly, the impact of transmission and other constraints that limit the type of resource available to meet

[38] LC 80 Round 1 Comments of Staff at 27
[39] LC 80 Round 1 Comments of Staff at 28

capacity needs, which do not bind/limit resource selection until after the 2-3 years of the analysis.

- Similarly, the UM1893 method to value energy is based on using electricity prices. The decrease in the electricity price forecast over the planning horizon in the Reference case is rightly identified by Staff as the reasoning for decreasing energy value. However, this approach might not be appropriate within portfolio analysis because the model has limited access to market purchases which are priced at the electricity prices. Any additional energy needed to meet energy needs while complying with HB 2021 must be addressed through new resource additions, whose net cost may be higher or lower than electricity prices. The net cost of these new resources would increase when accounting for transmission constraints. This dynamic, while captured endogenously within portfolio analysis, is not captured in the current UM 1893 methods and is the likely driver of the selection of EE within portfolio analysis. PGE also noted this in the last roundtable meeting prior to filing.[40]

Thus, as PGE noted in the filed CEP/IRP, established methods especially related to energy value estimation might not capture the value of EE when considering emissions and transmission constraints. This gap between electricity price and net cost of the marginal energy resource was labeled as the cost of clean energy. PGE reiterates the need to undertake additional study to determine how both HB 2021 and transmission availability impact avoided costs, especially energy related avoided costs for resources that can avoid further transmission buildout. PGE is currently undertaking an effort to understand how UM1893 avoided costs must evolve to replicate the results of portfolio analysis but has not made sufficient progress to provide an update at this time.

[40] March 30th roundtable available at: https://assets.ctfassets.net/416ywc1laqmd/74fBbECgfODO17Gkgffl3z/9a726ecb1032d9d5b6310588f35379b4/IRP_Roundtable_March_30_23-3.pdf

Chapter 4. Methods

4.1 Price forecasting

On the topic of price forecasting, AWEC states that PGE's market price forecast is not reliable; therefore, energy values and the portfolios and portfolio costs generated by ROSE-E are unreliable.[41] AWEC states that PGE's long-term market price forecast is not consistent with planned resource additions or planned sales of emitting energy.[42] Additionally, AWEC notes that PGE's PZM model does not consider transmission constraints leading to an inability to simulate dispatch needs and properly model variable energy resource (VER) curtailments.[43]

PGE's response

In this CEP/IRP and previous IRPs energy value has been useful to differentiate between potential incremental generation resources with the annual granularity of IRP portfolio modeling.[44] PGE agrees that this current CEP/IRP energy value construct is imperfect and appreciates AWEC highlighting this issue. The Company further agrees that there are assumptions used in previous IRPs regarding energy value that have the potential to break down with higher renewable penetration. Currently, the energy value used in the IRP analysis is created against a counterfactual of unspecified market purchases that might not be appropriate given the emission reduction targets associated with HB 2021.

PGE has previously recognized the granularity of energy accounting in portfolio analysis as an area of future improvement in order to better match the timing of energy generation with energy needs.[45] Moving from annual to monthly accounting of energy needs in portfolio analysis could help to differentiate between energy resources without relying on energy value by allowing for intra-annual variation in the timing of energy needs and renewable generation patterns to be accounted for in resource selection.

However, these areas of potential future improvement do not invalidate PGE's portfolio analysis results. Currently, resource additions in portfolio analysis are driven by needs and key constraints like transmission availability and emissions targets, not power prices. Conversely, in the 2019 IRP a main question of interest was the estimation of energy value, as

[41] LC 80 Round 1 Comments by AWEC at pp. 2
[42] LC 80 Round 1 Comments by AWEC at pp. 4-6
[43] LC 80 Round 1 Comments by AWEC at pp. 6-7
[44] Energy value ($/MWh) in the IRP has typically been estimated by summing the forecasted generation multiplied by the expected price for each hour.
[45] See meeting materials from PGE's March 30, 2023 roundtable meeting at https://assets.ctfassets.net/416ywc1laqmd/74fBbECgfODO17Gkgffl3z/9a726ecb1032d9d5b6310588f35379b4/IRP_Roundtable_March_30_23-3.pdf

the main driving factor for resource additions was their associated energy values. However, the use of energy value to distinguish between specific resources is not the driving force of current portfolio outcomes, and effectively the same quantity of incremental resource additions would be required even if the energy value of each were removed from the analysis. Portfolio costs produced in the IRP are used to compare portfolios against one another and because all portfolios rely on the same source of energy values, any shortcomings in the forecast of power prices that is applied consistently across all portfolios do not invalidate the insights gained from portfolio analysis. Additionally, the modification of power costs within PGE's General Rate Case does not necessarily invalidate the energy value forecast as AWEC implies in their comments. There are additional factors, such adverse energy market conditions, that can affect power costs and should be considered before assuming the energy value forecast is incorrect.

4.2 ELCC values

4.2.1 Reported ELCC values

Staff noted that the ELCC value of Gorge Wind in the 2023 CEP/IRP is "much larger than in the 2019 IRP Update."[46] They ask why this occurred. Staff also asked why there are differences between the tuned and untuned ELCCs calculated in the CEP/IRP.[47]

PGE's response

Resource ELCC values depend on the characteristics of the resource being evaluated as well as the base system in which they are tested. Both the Gorge Wind generation profile from the 2019 IRP Update and the relevant base system are different in the 2023 CEP/IRP. For these Reply Comments PGE tested the ELCC of the 2019 Gorge Wind shape in the 2023 CEP/IRP model and found that it has a lower value than the 2023 CEP/IRP resource, signifying that the new shape plays a role in the increased value compared to the 2019 IRP Update.[48] The shape in the 2023 CEP/IRP is based on publicly available NREL data and is further discussed in Appendix M. Supply-side options of the filed CEP/IRP.[49] The 2019 IRP Update shape was created by HDR, a consultancy, and is the same shape used in the 2019 IRP.[50]

[46] LC 80 Round One Comments of Staff at 44
[47] LC 80 Round One Comments of Staff at 44
[48] The 2019 IRP Update Gorge Wind shape in the 2023 CEP/IRP model had a summer/winter ELCC value of 42%/32%, respectively. For comparison, the annual ELCC value in the 2019 IRP Update for Gorge Wind was 25%, and the 2023 CEP/IRP Gorge Wind shape in the 2023 CEP/IRP is summer/winter 47%/39%, respectively.
[49]https://downloads.ctfassets.net/416ywc1laqmd/6B6HLox3jBzYLXOBgskor5/63f5c6a615c6f2bc9e5df78ca27472bd/PGE_2023_CEP-IRP_REVISED_2023-06-30.pdf
[50] See Chapter 6 of the 2019 IRP for more information: https://portlandgeneral.com/about/who-we-are/resource-planning/combined-cep-and-irp/combined-cep-irp-resources-materials

When tested in the 2023 CEP/IRP model, the 2019 IRP Update Gorge Wind shape has a higher ELCC than in the 2019 IRP Update, indicating that the base system also plays a role in the different ELCC value. One potentially synergistic change to the base system between the 2019 IRP Update and the 2023 CEP/IRP is the inclusion of 400 MW of 4-hour RFP proxy batteries.[51] The change in resource ELCC value between two different base systems is often referred to as the "portfolio effect", where the resource portfolio (or base system) can alter resource ELCC values. This was partly discussed in the August 2022 Roundtable as well as in Appendix J of the CEP/IRP (with a focus on storage resources).[52]

Another portfolio effect item is resource saturation, which can lead to lower ELCC resource values. For example, a base system with high levels of solar resource may see reduced outages during daylight hours since existing solar is generating in those hours. This reduces the ELCC value of incremental solar resources since they have fewer outages available to solve. Tuned ELCCs are tested in a different system than untuned ELCCs and include the Preferred Portfolio resources. As a result, they have a different base system than the untuned ELCCs (and a different base system for each tuned year tested). This leads to different ELCC values between the tuned and untuned approaches. For the untuned ELCCs the CEP/IRP currently only includes same resource saturation (for example the quantity of Wasco Solar added reduces the next increment of Wasco Solar's ELCC), however, it does not incorporate similar resource saturations (for example, an addition of Christmas Valley Solar does not currently reduce the next increment of Wasco Solar's ELCC). More work is needed to better incorporate the portfolio effect into future planning cycles.

4.2.2 ELCC calculation methodology

RNW provided a number or ELCC methodology comments and suggests that PGE incorporate them in the next planning cycle.[53] Specifically, they ask PGE to take the portfolio effect into account when calculating ELCC values, to calculate ELCC values in multiple years, to include an ELCC validation process, and to think of ELCCs as more of a surface than a curve.[54] AWEC comments that the ELCC values in the CEP/IRP do not consider the impact of similar resources being added to the portfolio.[55] They think this may overstate resource ELCC values and lead to a capacity deficit Preferred Portfolio.

[51] Updated to 475 MW in the Addendum to reflect committed procurement quantities.
[52] PGE August 2022 Roundtable at minute 47 to 133
[53] LC 80 Round One Comments of RNW at 14-16
[54] LC 80 Round One Comments of RNW at 14-16
[55] LC 80 Round One Comments of AWEC at 8-9

PGE's response

PGE agrees that the portfolio effect can have a tangible impact on estimates of resource ELCC. It was partly discussed in the August 2022 Roundtable as well as in Appendix J of the CEP/IRP (with a focus on storage resources).[56] For example, a battery ELCC may change (often improve) if tested in an energy adequate rather than deficit system since it can charge more reliably. Another aspect of the portfolio effect is resource saturation. For example, a wind resource ELCC may decline if tested in a system that already includes wind resources that follow a similar generation pattern.[57] The multiyear ELCC recommendation suggested by RNW is like the portfolio effect, assuming Preferred Portfolio resources are added to the system when ELCCs are tested. AWECs comments are related to the portfolio effect as well, specifically resource saturation due to the addition of similar resource types.

PGE will consider expanded analysis of the portfolio effect in future CEP/IRPs, potentially by running iterative ELCCs in key years. For example, ELCCs could be run for the first year of significant deficit and run again in a later year while incorporating Preferred Portfolio resources. However, expanded analysis of the portfolio effect will increase workload and may result in compromises like fewer resources being tested and/or fewer resource levels being tested.

In the 2023 CEP/IRP PGE tests ELCC values using a 'ladder' approach. Larger and larger nameplate MW amounts of the same resource are added to the portfolio to provide an estimation of how the ELCC value changes due to resource saturation (typically they decline). PGE agrees that ELCC values should ideally be treated like a surface rather than a curve, with multiple resources of different technologies being added to the portfolio simultaneously. However, analyzing an extra dimension of ELCC analysis increases workload and may not be feasible. For example, the Northwest Power & Conservation Council calculated the ASCC (similar to ELCC) for seven resource types at two levels of capacity and found that to "fill the ASCC array with every combination of resource type and capacity addition requires 128 studies."[58] PGE tested ELCC values of over 20 resources (including transmission variations) for the CEP/IRP. If an ELCC array was constructed at two addition levels and with 20 resources, there would be over 1 million resource combinations. PGE is currently evaluating the trade-offs presented between precision and increased modeling time.

One potential approach to validating ELCC values is back-checking the Preferred Portfolio. This involves taking the Preferred Portfolio resources, which are selected by the portfolio analysis model, and running them through the adequacy model to test the system adequacy level. This helps determine if the resources selected are providing the estimated amount of capacity based on their ELCC values, or if the portfolio effect is skewing the ELCC values

[56] PGE August 2022 Roundtable at minute 47 to 133
[57] Most variable energy resources see decreasing ELCC values as more of the same resource is added to the portfolio.
[58] This is equal to 2^7: https://www.nwcouncil.org/2021powerplan_associated-system-capacity-contribution/

(which would result in an overly surplus or deficit system). A multiyear back-check was performed as part of these comments and can be found in **Section 4.3.1, Resource adequacy metrics in the CEP/IRP**, with loss-of-load-hours and loss-of-load-events reported out for select CEP/IRP years. PGE directs AWEC to this section as well regarding their system adequacy concerns. PGE is open to exploring other ELCC valuation methods in the next CEP/IRP.

4.3 Resource adequacy

4.3.1 Resource adequacy metrics in the CEP/IRP

Staff notes that PGE's adequacy standard, 2.4 loss-of-load hours (LOLH) per season, results in a 4.8 annual LOLH standard. They also ask for PGE to calculate the LOLH and loss-of-load-expectation (LOLE) of each year in the CEP/IRP while including the Preferred Portfolio in the adequacy model, and ask why PGE chose to plan for that level of reliability.[59] AWEC raises concerns that PGEs Preferred Portfolio may be capacity deficient due to the estimation method used for resource ELCCs and due to the Preferred Portfolio not being tested in an hourly adequacy model.[60]

PGE's response

In the CEP/IRP modeling workflow, the LOLH standard is passed from the adequacy model to the portfolio model as the amount of effective capacity, by season, that needs to be acquired to maintain adequacy. The 2.4 LOLH is an interpretation of the 1-day-in-ten year standard and was used in the 2019 IRP and 2019 IRP Update. The standard is applied seasonally in the 2023 CEP/IRP to ensure a seasonally balanced system.[61]

Applying a 2.4 LOLH per season does not result in 4.8 LOLH annually in the CEP/IRP. For example, for year 2026, the summer capacity need in the Addendum is 718 MW, the winter need is 522 MW, and the annual need (which is not published in the CEP/IRP) is 622 MW. As a result of acquiring enough capacity to meet summer and winter need, annual need is met as well. This is further demonstrated in **Table 3** which shows annual adequacy metrics for the Preferred Portfolio in the 2023 CEP/IRP.

At different stages of portfolio analysis PGE checked the adequacy of year 2030 for the filed CEP/IRP and year 2028 of the Addendum.[62] **Table 3** provides annual LOLH and LOLE metrics for select years out of the filed IRP. Most of these years were tested to address these

[59] LC 80 Round One Comments of Staff at 43
[60] LC 80 Round One Comments of AWEC at 7-8
[61] As opposed to a system that is overly adequate in one season, deficient in another, but balanced on the year.
[62] 2028 was tested in the Addendum to align to the Action Plan capacity target and to avoid modeling generic variable energy resource which begins to appear in the Addendum in 2030.

Comments (as was the calculation of the LOLE metric).[63] The values are estimated by adding the Preferred Portfolio resources to the adequacy model. The LOLE values are provided for informational purposes only (LOLE is not used in the CEP/IRP).

Table 3. Preferred Portfolio LOLH and LOLE values, filed CEP/IRP

Year	LOLH	LOLE
2026	1.913	0.244
2027	1.091	0.161
2028	1.577	0.213
2029	1.459	0.307
2030	2.497	0.565
2036	0.145	0.063
2043	1.378	0.292

Looking at the values from the filed CEP/IRP, the resource adequacy levels stay between 1.091 and 2.499 LOLH from 2026 through 2030, and in year 2043. Due to the portfolio effect (resource interactions inside the portfolio) and the portfolio model having a static view of ELCC values, there will likely always be some difference between the LOLH target and the LOLH value after back-testing.[64] Year 2036 is capacity surplus. This surplus is partly due to the portfolio model building surplus capacity resources in preparation for the 2040 capacity need increase and may also be due to the portfolio effect as thousands of MW of new resources are added to the system by 2036.[65] As this analysis conducted by PGE to address Staff's concerns shows, LOLH values from the filed CEP/IRP are consistent with the 2.4 LOLH standard throughout the planning horizon.

LOLE values are numerically lower than LOLH values. This is due to the LOLE calculation which indicates number of adequacy events (which may be multiple hours in length) divided by number of years simulated, versus LOLH which indicates number of hours (which could occur in the same event) divided by the number of years simulated. As a result, the numerator in the metric calculation, and thus the final metric value, is nearly always larger with LOLH (hours) versus LOLE (events).[66]

Table 4 provides LOLH and LOLE values for the Addendum Preferred Portfolio. In the Addendum, the model indicates LOLH values between 1.531 and 1.994 from 2026 through

[63] LOLE is interpreted as the number of days with an outage divided by total years simulated. A consecutive two-day outage is interpreted as two different events, two separate outages in the same day are interpreted as one event.
[64] For example, in the 7th Power Plan, which targeted a 5% LOLP adequacy metric, the Northwest Power & Conservation Council targeted back-checked portfolio results between 2% to 5%. Please see page 11-4: https://www.nwcouncil.org/sites/default/files/7thplanfinal_allchapters_1.pdf
[65] The need for capacity rises sharply in 2040 when emitting resources can no longer be used for retail load service.
[66] PGE uses 2.4 LOLH as an interpretation of a one-day-in-ten outage standard, allowing up to 24 hours of outage per ten years in the model. Some organizations use 0.1 LOLE as a one-event-in-ten standard, allowing one event per ten years. Since most adequacy events are shorter than 24 hours the 0.1 LOLE standard is typically stricter than a 2.4 LOLH standard.

2028. Years 2029 and 2030 are capacity surplus. This is due to the portfolio model needing more clean energy to meet HB 2021 targets, having limited resources available to select, and the assumed characteristics of those resources. For example, 553 MW of Wyoming wind and Desert SW solar resource are added in 2029, among other resources. With their associated transmission they provide 553 MW of effective capacity. However, the capacity need increase from 2028 to 2029 is 116 MW in the winter and 211 MW in the summer (164 MW average). As a result, to meet energy needs, the system is capacity surplus in those years. The Addendum portfolio is also capacity surplus in 2036 and in 2043. This is likely due to a multitude of factors including the portfolio effect and the max build constraint that smooths capacity additions ahead of the 2040 zero emissions requirement as discussed above. Like the filed CEP/IRP, the 2.4 LOLH target is met in all years, with some years capacity surplus due to the need to acquire high capacity resources to meet energy needs in portfolio analysis, as well as the portfolio effect and other factors in later years.

Table 4. Preferred Portfolio LOLH and LOLE values, CEP/IRP Addendum

Year	LOLH	LOLE
2026	1.994	0.260
2027	1.945	0.264
2028	1.531	0.191
2029	0.051	0.014
2030	0.051	0.020
2036	0.313	0.068
2043	0.385	0.020

4.3.2 Resource adequacy methods in future CEP/IRPs

RNW provided several comments on PGE's resource adequacy needs assessment to be taken into consideration for the next planning cycle.[67] Specifically, RNW asks that PGE incorporate a suite of adequacy metrics into its adequacy modeling, that PGE should not align the adequacy models outage distribution curve from greatest to smallest, for PGE to investigate tail adequacy risks, for PGE to incorporate economic considerations in the adequacy model to assess the cost/benefit of different adequacy levels/resource additions, and to incorporate the ability to buy market power during daylight hours due to increased levels of solar power in the West.[68]

[67] LC 80 Round One Comments of RNW at 9-13
[68] LC 80 Round One Comments of RNW at 9-13

PGE's response

PGE disagrees that a suite of planning metrics is necessary for a resource adequacy study. Many adequacy studies, including the WRAP, are based upon single metric criteria.[69] That said, PGE provides a view of another adequacy metric, loss-of-load-events (LOLE) as part of this comment response in **Section 4.3.1, Resource adequacy metrics in the CEP/IRP**. Additionally, PGE plans to engage in discussions with the Northwest Power & Conservation Council, and other stakeholders who want to contribute, regarding the benefits of a multi-metric approach, and will consider whether such a change would be an improvement to PGE's current approach.

PGE disagrees with the comment that outages should not be aligned from largest to smallest when calculating LOLH. The largest to smallest alignment method used by PGE for capacity determination in adequacy models is used by other organizations, including the Power Council in the 7th Power Plan, and provides increased efficiency over an iterative approach.[70] PGE also disagrees that the adequacy model should incorporate economics to value adequacy since PGE does not use a value-of-lost-load metric.[71] Finally, tail risk analysis is interesting from a qualitative perspective, but difficult to draw actionable results from. That said, the Company is open to working with stakeholders to explore tail risk analysis in the next planning cycle, in part to see if the types of adequacy events in the model are changing over time.

PGE agrees that a more granular power market should be incorporated into the adequacy model. This is also noted on page 14 of the CEP/IRP Addendum. This could be a solar market as suggested by RNW, a more granular look at hourly market power availability, a combination of the two, or another approach.

4.3.2.1 WRAP and CEP/IRP adequacy

Staff asks that PGE in future CEP/IRPs take the WRAP into consideration including making adjustments to system reliability need, capturing savings opportunities related to WRAP, and capturing other program benefits.[72] RNW asks PGE to incorporate WRAP related items into the CEP/IRP while noting that adequacy in the CEP/IRP and the WRAP will remain parallel

[69] The WRAP plans to use a 1-in-10 LOLE metric, please see page 57: https://www.westernpowerpool.org/private-media/documents/2023-03-10_WRAP_Draft_Design_Document_FINAL.pdf
[70] Please see page 11-19 ad Figure 11-7: https://www.nwcouncil.org/sites/default/files/7thplanfinal_chap11_systemneedsassess_1.pdf
[71] Economics in an adequacy model is also useful for energy-limited resource dispatch logic, particularly if the model is using a longer duration (e.g., annual) timestep. For example, a model may consider the opportunity cost of using hydropower in January for economics even though it could still encounter an adequacy event later in the year. Given PGE's adequacy model run time (currently 1 week, or 168 hours) this consideration is less important for the PGE model today.
[72] LC 80 Round One Comments of Staff at 43-44

processes for the foreseeable future.[73] They recommend discussion and analysis of WRAP compliance in the CEP/IRP, using WRAP outputs to inform the CEP/IRP adequacy analysis on items like power market availability and the risk of transmission curtailment, and to improve CEP/IRP wrap alignment and integration via discussions with WRAP participants, the PUC, and other stakeholders.

PGE's response

As noted in the CEP/IRP, PGE plans to work "with WRAP participants and state regulators to ensure that state-level IRPs complement and work in harmony with regional resource adequacy programs."[74] PGE continues to engage with the WRAP effort and stakeholders, and continues to seek avenues to inform future CEP/IRP work via the WRAP, including capturing potential WRAP benefits. As noted in the CEP/IRP "There may be a future opportunity to link IRP power market availability assumptions to work done by the…" WRAP.[75] PGE may explore other WRAP related outputs and insights, including transmission curtailment risk, and how they can be built into future CEP/IRPs.

PGE is still assessing potential jurisdictional and methodological concerns between the WRAP, developing state-level RA frameworks, and CEP/IRP resource adequacy. For example, if the CEP/IRP finds the system to be adequate but the WRAP identifies an adequacy concern it is unclear what the correct course of resource action would be. For example, if estimates from the WRAP were higher than PGE's evaluated adequacy need estimates, would this be sufficient justification for an incremental resource addition? Or if PGE indicated a resource need and the WRAP indicated sufficiency, would PGE be expected to acquire additional resources? Some of these questions may be discussed in upcoming stakeholder meetings, WRAP meetings, OPUC dockets, or other forums.

Additionally, there are questions regarding if the WRAP planning margin can be used for long-term planning in the CEP/IRP, and if WRAP models/methodologies can be leveraged to produce ELCC values for CEP/IRP proxy resources. For example, for CEP/IRP adequacy, can the planning margin generated by the WRAP be extended outwards for comparison to the CEP/IRP or for resource action guidance? Specific to resource valuation, should efforts be made to align incremental resource ELCC values between the WRAP and the CEP/IRP to avoid potential seams issues?[76] PGE looks forward to continued dialogue with the WRAP and other stakeholders to help discuss and address these items, among other concerns.

[73] LC 80 Round One Comments of RNW at 47-50
[74] LC 80 filed PGE 2023 CEP/IRP, at 66
[75] LC 80 filed PGE 2023 CEP/IRP at 511
[76] For example, the CEP/IRP could assess the ELCC of a resource at 40% whereas the WRAP models value it at 20%. This could lead to PGE identifying resources that are sufficient from an internal modeling perspective but insufficient (or overly surplus) from a WRAP perspective.

4.4 Operations

4.4.1 Adapting to the changing power system

The Energy Advocates discuss PGE's response to an Initial Comment response regarding the use of generic plant data in mid- and long-term models and actual data used in operational models.[77] They note that as more variable energy resources, demand response, and energy efficiency enter the system "operational strategies will need to evolve."[78] They specify that their Initial Comment was focused on how PGE plans to adapt to the changing power system. AWEC also notes that PGE should consider how to manage "energy shaping needs" given the decreasing amount of dispatchable resource energy that PGE can retain for retail load service.[79]

PGE's response

PGE agrees with the Energy Advocates and is actively evaluating the possibilities of a more granular modeling process for the next CEP/IRP, in part due to the projected increases of VER and demand side resources. We recognize the challenge of planning for a power system that will be different than the system today, and look forward to working with regulators, stakeholders, and other interested parties as we improve our CEP/IRP modeling approach. PGE discussed some of these modeling improvements at the March 2023 Roundtable meeting.[80] PGE notes these modeling improvements are long-term planning focused, and that the CEP/IRP provides a long-term plan for PGE, not an operations focused plan. Operations will also adjust in real-time based on actual conditions like weather, supply/demand dynamics, economic considerations, and more. As discussed in PGE's reply to Initial Comments, operations will continue to change to meet GHG reduction targets and adequacy requirements.[81]

4.4.2 Economic dispatch

Energy Advocates notes that the intermediary GHG model determines economic dispatch for retail load service before CO_2e targets are considered, and then assumes the excess generation after the target is met is sold out of state.[82] They ask for PGE to provide the details

[77] LC 80 Round One Comments of Energy Advocates at 10
[78] LC 80 Round One Comments of Energy Advocates at 10
[79] LC 80 Round One Comments of AWEC at 8
[80] Please see the IRP Limitations and Areas for Improvement section starting on slide 40: https://assets.ctfassets.net/416ywc1laqmd/74fBbECgfODO17Gkgffl3z/9a726ecb1032d9d5b6310588f35379b4/IRP_Roundtable_March_30_23-3.pdf#page=40
[81] LC 80 Round 0 Comments: PGE Response at 40-41
[82] LC 80 Round One Comments of Energy Advocates at 11-12

of the economic dispatch calculation and stated that this calculation should consider health impacts of thermal power plants and the social cost of carbon.[83] Both the Energy Advocates and NewSun suggest that thermal generation above that used for retail load should be reduced.[84]

PGE's response

Economic dispatch of thermal resources is estimated in the PZM model and is then passed to the intermediary GHG model. This process involves the following steps:

- Running the WECC-wide model to establish power prices in 39 different Price Futures
- Running the PZM model on economic dispatch in conjunction with those power prices to establish thermal plant dispatch for each Price Future[85]
- Using the intermediary GHG model to adjust thermal generation (estimated in the PZM) based on historical ratios of what is kept for retail load service versus sold on the market. It then adjusts generation for retail load service to meet GHG targets (usually a downward adjustment) and assumes the energy difference between economic dispatch and retail load service is sold on wholesale markets.

An EPA-derived social cost of carbon is included in some of the 39 Price Futures, although it is not included in the reference case Price Future. Carbon pricing is excluded since it does not exist in Oregon today, since HB 2021 reduces the possibility of future utility sector carbon pricing in Oregon (HB 2021 already targets utility emissions), and because the CEP/IRP focuses on minimizing costs under current and expected policies. These Price Futures feed into portfolio analysis. As a result, and due to our need to reduce emissions via HB 2021, PGE finds the current analytical process to be robust and does not believe the additional evaluation of the social cost of carbon or other externalities would lead to a tangibly different plan.

PGE disagrees with both the Energy Advocates and NewSun that thermal generation above that used for retail load should necessarily be reduced, as that is not a requirement of HB 2021. PGE continues to believe that economics will continue to drive thermal modeling even in the presence of Oregon's HB 2021 and all other applicable carbon regulation in Oregon or other states. Demand for thermal generation in other states will drive economic dispatch, but that demand is increasingly subject to carbon and clean energy policies in states. Additionally, in determining the structure of its thermal modeling PGE relied on guidance

[83] LC 80 Round One Comments of Energy Advocates at 11-12
[84] LC 80 Round One Comments of Energy Advocates at 11 and NewSun at 11.
[85] As discussed in Appendix H.1.2 Aurora PGE Zone Model, "Aurora simulates PGE existing dispatchable generation resources, contracts, and new resources using economic dispatch based on electricity prices and associated risk variable inputs consistent with each Price Future. When economically dispatched, resources will generate when resource dispatch cost is lower than the electricity market price and will not generate when market purchases are cheaper."

from Staff who suggested that economic dispatch should determine the total output of the Company's existing thermal fleet. As mentioned below, the improvement of its modeling of thermal resources will continue to be a priority for the Company in the face of market and policy developments, and PGE will also continue working with Staff and stakeholders to help determine the answers to these modeling questions.

4.5 Emissions accounting

4.5.1 Sub-annual emissions modeling

RNW comments that the CEP/IRP should include "Sub-Annual" accounting and analysis of emissions and include an operations-based view of emissions.[86] They note that sub-annual accounting is important due to the seasonality of load and generation profiles.[87] They also state that PGE should improve its analysis on curtailment and overgeneration risks.[88] They state that PGE's plan to sell excess generation into the market may be problematic due to generation correlations among Western resources, and without the ability to net clean energy against thermals that PGEs emissions strategy may be at risk.[89] Finally, they find that the current annual PGE modeling approach does not allow for identification of increased integration needs for variable energy resources.[90]

PGE's response

PGE agrees that annual energy/GHG modeling in the CEP/IRP does not account for seasonal variations of VERs and load. This limitation is noted in the March 2023 Roundtable meeting and we are committed to evaluating possible improvements to this approach.[91] CEP/IRP modeling portfolio modeling is currently done on an annual basis. It is not intended to be an energy or emissions netting strategy per se, and was developed to meet the annual evaluation used in portfolio analysis. At the March 2023 Roundtable we also identified VER integration as an area to evaluate for future modeling enhancements. This could include an investigation into sub-hour flexibility modeling.

PGE agrees that more granular modeling can provide insights into its clean energy position and overgeneration risks. Please see **Section 4.7.1, Hourly analysis of the Preferred**

[86] LC 80 Round One Comments of RNW at 20-23
[87] LC 80 Round One Comments of RNW at 20-23
[88] LC 80 Round One Comments of RNW at 20-23
[89] LC 80 Round One Comments of RNW at 20-23
[90] LC 80 Round One Comments of RNW at 20-23
[91] Please see the IRP Limitations and Areas for Improvement section starting on slide 40 of the March 2023 Roundtable: https://assets.ctfassets.net/416ywc1laqmd/74fBbECgfODO17Gkgffl3z/9a726ecb1032d9d5b6310588f35379b4/IRP_Roundtable_March_30_23-3.pdf#page=40

Portfolio for a newly conducted hourly Aurora PZM emissions analysis using the Preferred Portfolio.

4.5.2 Resource emissions shuffling

RNW raises concerns regarding resource 'shuffling.'[92] For example, they state that under the current modeling framework PGE could sell Colstrip into the power market while simultaneously buying unspecified market power at a lower emissions intensity rate, thus exchanging its higher emissions in favor of lower emissions. This would allow PGE to retain more GHG-emitting energy in the Preferred Portfolio. RNW states that this is shown in Table 4 of the Addendum since Beaver's annual generation retained for retail load service falls by 34 MWa while market purchases increase by 39 MWa as compared to the filed CEP/IRP in year 2024. RNW also provided broader comments regarding how emissions are assigned to PGE resources, and asks if there are implications for the Commissions determination of if the CEP/IRP is in the public's interest.

PGE's response

The intermediate GHG model does not consider resource 'shuffling' strategies. Rather, it effectively performs two tasks that are guided by economic dispatch and historical data:

1. It adjusts, for emitting resources, simulated economic dispatch (for PGE resources) or historical dispatch (for non-PGE resources) by historical ratios to account for retail load service vs. wholesale sales.
2. After adjusting for energy retained for retail load service the intermediate GHG model then adjusts emitting resource dispatch (usually downward) to ensure the GHG targets are met.

PGE disagrees with RNW comment about employing a resource 'shuffling' strategy in the CEP/IRP. If RNW's assertion was accurate PGE's modeling would show the retention of the lowest emission rate resources for retail load service and sale of the most emission intensive resources to the market. This would allow PGE to maximize the amount of emitting generation kept for retail load service. Instead, PGE's modeling uses historical data to guide how resources are retained for retail load service versus sold on the wholesale market. PGE finds this approach the most appropriate, as it relies on historical values that provide a non-biased calculation of how much power is typically retained for retail load versus sold on the market.

PGE also disagrees with RNW's statements about the modeled operation of Beaver. As explained in the July 7th Addendum, heat rate errors associated with thermal resources in the

[92] LC 80 Round One Comments of RNW at 23-25

filed CEP/IRP were corrected for the Addendum. This led to Beaver generating less energy in the CEP/IRP based on corrected economic dispatch. In the early years, like 2024, the GHG model often cannot move generation from one PGE resource (like Beaver) to another. This is due to PGE resources already being at their maximum retail load service levels allowed (which is set by Aurora PZM and the historical load service vs sales ratios). This is why the decreased Beaver generation in 2024 is mostly offset by market unspecified in 2024.

Regarding assignment of emissions to resources, for HB 2021 compliance the CEP/IRP targets emissions associated with retail load service. We also track and report total emissions (including those associated with wholesale sales) in the CEP/IRP and in the accompanying CEP Data Template.

4.5.3 Market unspecified emissions rate

RNW states that PGE suggests in the CEP/IRP that the market unspecified emissions rate should be reconsidered due to the increasing number of clean energy resources in the West.[93] They postulate that the demand for clean energy resources will grow due to climate policies, and the increased demand will lead to more clean resources being "claimed" or specified as emissions free, resulting in a higher future emissions rate for market unspecified resources.

PGE's response

PGE strongly disagrees with the claim that the CEP/IRP asks for a reconsidered market unspecified emissions rate and finds that statement as a mischaracterization of the CEP/IRP. The CEP/IRP does ask for improved specified resource tracking across the West, which could lead to some purchases that are currently unspecified becoming specified. Improved resource tracking will likely be necessary as utilities in the West decarbonize. In their comments, RNW notes that is already starting to occur, as "previously unspecified hydroelectric facilities are being newly specified in the portfolios of utilities…"[94]

Specific to the filed CEP/IRP page numbers highlighted by RNW:

- On page 16 we note that "PGE is committed to working with regional organizations to improve emissions tracking and accounting across Western markets to provide better visibility into the GHG content of market power" while also discussing that there are likely non-emitting resources as part of unspecified purchases. This CEP/IRP section is about improving resource tracking so we can identify and correctly account for clean power purchases.

[93] LC 80 Round One Comments of RNW at 25-27
[94] LC 80 Round One Comments of RNW at 26

- On page 95 we note that using market unspecified rates "may result in certain MWh receiving a higher CO_2e intensity compared to the actual CO_2e intensity of unspecified market purchases." In an Initial Comment response PGE clarified that some purchases may be above the rate as well.[95]
- On page 122 we clarify in a footnote that Figure 42 shows energy need "Assuming no change in the emissions rate used to account for GHG emissions associated with market purchases from unspecified sources." PGE does not find this sentence to be suggestive of a need to reconsider the market unspecified rate.
- The sensitivity on page 137 shows the impact on energy needs if half of unspecified purchases were reclassified as specified GHG free. This is a switch from unspecified to specified, not a claim that the market rate should be reconsidered. The sensitivity concludes with the sentence "These results suggest that determining the appropriate emission factor of market purchases will be critical going forward to accurately determine resource needs." This sentence, in the context of the broader sensitivity, is about being able to better specify the source and CO_2e intensity of market purchases.

There is a significant difference between noting the potential differences between the current unspecified rate actual emissions and advocating for DEQ to change its emissions methodologies. Nowhere in the above locations cited by RNW does PGE do the latter.

Finally, at this point PGE does not have a strong prediction regarding how the market unspecified emissions rate could change. It is plausible, as RNW speculates, that the growth in non-emitting generation could be offset by the competition for it. Which impact is larger, the growth in non-emitting generation or the demand for it, remains to be seen.

4.5.4 Power system modeling comparison

RNW provides a comparative analysis of how other organizations and utilities are conducting analysis to incorporate rapid decarbonization into electric power planning.[96] They draw insights from LADWP, SMUD, and the CPUC, discussing how their modeling is similar to, and different than, PGE's.[97]

PGE's response

As noted in the March 2023 Roundtable meeting, and in **Section 4.5.1, Sub-annual emissions modeling** of this document (among other locations), PGE is planning

[95] See LC80 Round 0 Comments: PGE Response at 46-47
[96] LC 80 Round One Comments of RNW at 27-29
[97] LC 80 Round One Comments of RNW at 27-29

energy/emissions modeling changes for the next CEP/IRP cycle and is appreciative of the information regarding other modeling approaches.[98]

4.6 Input assumptions

4.6.1 QF and community solar input assumptions

REC objects to the assumption that qualifying facility (QF) contracts do not renew and asks PGE to include information from other utilities when assessing renewal rates, to include information from the three historical PGE renewals that have occurred, and to include the Covanta Marion project as a QF renewal.[99] They also recommend using a 50 percent success rate for 202 projects (rather than 100 percent), noting the two projects that failed between the CEP/IRP filing and the Addendum, and noting historical failure rates support 50 percent.[100] Related to community solar, REC comments that PGE should only include energized community solar projects and only forecast future program growth as a CEP/IRP sensitivity.[101]

PGE's response

Regarding QF renewal rates, PGE has virtually no QF renewal history that would be reasonable to serve as a basis for forecasting a future renewal rate. The three projects that have renewed have a cumulate nameplate of 0.49 MW and are not usable proxies for estimating other QF renewals. We also find excluding the Covanta Marion project from the QF renewal calculations as appropriate. PGE does not treat every facility less than 80 MW as a QF, and Covanta Marion is not delivering power to PGE under a QF contract.

We also find using other utilities' renewal rates as inappropriate. There are vastly different conditions for QFs across different states and within Oregon, including, but not limited to: QF contracting process, avoided cost prices, standard QF terms and conditions, diverse interconnection processes, transmission constraints, and mix of on-system and off-system projects. In addition to these factors being different across utilities, and consistent with the March 30, 2023 Roundtable presentation, the number of QF contracts each utility holds, the technology mix for which they hold contracts for (e.g., PacifiCorp holds a large amount of legacy hydro), and the time period for which these contracts were entered into, are all vastly different.[102] Therefore, it is not appropriate to use the renewal rates of other utilities as a basis for PGE's renewal rate.

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[98] Please see the IRP Limitations and Areas for Improvement section starting on slide 40 of the March 2023 Roundtable
[99] LC 80 Round One Comments of REC at 2-8
[100] LC 80 Round One Comments of REC at 2-8
[101] LC 80 Round One Comments of REC at 9-11
[102] Please see slides 51-59 of the March 2023 Roundtable

We still find the 100 percent success rate for 202 projects to be appropriate. Although two facilities from a single developer terminated between the filed CEP/IRP and the Addendum, PGE does not believe that the outcome of projects from a single developer is sufficient additional information to change its position that a 100 percent success rate for Schedule 202's is reasonable and appropriate from a long-term planning perspective. In addition, given the size of the projects in scope for Schedule 202, PGE should be able to account for the fact that these developers should not be entering into speculative contracts, and that their ability to deliver should match the level of commitment.

Regarding community solar, PGE directs REC to OPUC Order 17-232, section "VI. ORDER", which in part states "When assessing load-resource balances in its integrated resource planning, an electric company must include forecasts of market potential for community solar projects..." PGE interprets this order, in part, as requiring a community solar forecast to be included in the adequacy model.

4.6.2 Hydrogen input assumptions

RNW provided multiple comments and questions on hydrogen modeling.[103] Regarding costs, they ask what cost components are used from a consultancy study, and if inflation and IRA credits are accounted for.[104] They also asked for PGE to ensure that any hydrogen produced is "green" hydrogen, recommend modeling hydrogen "availability" in locations with a renewable energy surplus, and suggest pairing hydrogen analysis with analysis of renewable overgeneration.[105] They also ask PGE to consider costs associated with incorporating hydrogen leakage technology into storage and pipeline cost estimates.

PGE's response

Specific to the hydrogen cost components from Monogrid and Hunter, reference case costs are based on the moderate scenario values with intermediate years based on interpolation.[106,107] Inflation is applied annually to escalate from base year values. Inflation Reduction Act tax credits are assumed for the production of hydrogen, construction of the energy storage facility, and resulting generation of non-emitting energy. As with other resources, tax credits are assumed to be monetized in the year generated.

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[103] LC 80 Round One Comments of RNW at 17-18
[104] LC 80 Round One Comments of RNW at 17-18
[105] LC 80 Round One Comments of RNW at 17-18
[106] Mongrid et al., "2020 Grid Energy Storage Technology Cost and Performance Assessment." Pacific Northwest National Laboratory. December 2020. Retrieved from: https://www.pnnl.gov/sites/default/files/media/file/Final%20-%20ESGC%20Cost%20Performance%20Report%2012-11-2020.pdf
[107] Hunter, et al., "Techno-economic analysis of long-duration energy storage and flexible power generation technologies to support high variable renewable energy grids." Retrieved from: https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3720769

PGE agrees that 'green' hydrogen must be generated using GHG free electricity and agrees that understanding the projected future time periods of clean energy surpluses could be useful when considering hydrogen production. Regarding the location of the hydrogen production facility, PGE is evaluating this comment given the ability to transmit power from clean energy resources to the production facility.

The current CEP/IRP hydrogen analysis is largely exploratory and non-actionable. Future analysis of hydrogen may, if appropriate, include additional details and costs associated with detecting and mitigating hydrogen leaks. We will work with stakeholders to develop appropriate resource characteristics and emissions accounting when considering hydrogen in future planning work.

4.6.3 AdopDER inputs

The Energy Advocates ask PGE to include in the AdopDER model specific Oregon low/moderate income incentives, specifically the Energy Trust of Oregon's Solar Within Reach Incentive and the Oregon Department of Energy Solar and Storage Rebate.[108] They note that inclusion of those programs would lead to a higher distributed PV forecast.[109] They also recommend the Commission require PGE to include those incentives in the AdopDER model for future work.[110]

PGE's response

PGE did update our solar forecasting methodology in the updated DER forecast provided in the Addendum to reflect higher incentives available to low- and moderate-income customers through Energy Trust's Solar Within Reach program offering. This decision was made based on feedback collected through the DSP regarding desire on the part of some stakeholders to see these incentives added to PGE's forecast methodology.[111] PGE acknowledges that this update should have been noted in the narrative write-up accompanying the DER forecast addendum.

4.7 Temporal granularity

4.7.1 Hourly analysis of the Preferred Portfolio

Staff express concern that PGE's modeling may not provide a realistic estimate of GHG emissions associated with portfolios due in part to temporal granularity limitations. Staff

[108] LC 80 Round One Comments of Energy Advocates at 7
[109] LC 80 Round One Comments of Energy Advocates at 7
[110] LC 80 Round One Comments of Energy Advocates at 7
[111] See Order 23-069 Appendix A pp. 11-12 available at: https://apps.puc.state.or.us/orders/2023ords/23-069.pdf

presents a draft of an hourly economic dispatch study which estimates GHG emissions associated with serving retail load using an approximation of PGE's Preferred Portfolio. Staff report that their initial findings forecast higher GHG emissions toward the end of the 2020's than PGE is forecasting. For comparison against their initial findings, Staff request that PGE conduct hourly dispatch analysis of the Preferred Portfolio under Reference Case conditions, that ensures load balance in each hour and tracks hourly dispatch, variable costs, and GHG emissions by resource as well as hourly market purchases and market sales. They request that PGE report annual portfolio costs and GHG emissions based on the simulation and that PGE provide transparency into how purchases and sales affect the GHG emissions associated with meeting load.[112] RNW make a related comment, indicating that PGE's current annual modeling framework lacks the temporal granularity to accurately account for GHG emissions. Accordingly, RNW suggests that PGE should adopt an hourly or systems-level analysis of its emissions target.[113]

PGE's response

PGE appreciates Staff's input into this topic, as emissions accounting is critical CEP/IRP analysis and determining the appropriate level of granularity for modeling is foundational to that effort. However, judgment is required whenever considering increasing the requirements in one area: increasing temporal granularity (or any other level of precision) can bring a sharper focus on the specific area but can also increase the time required to investigate individual components. When considering the magnitude of other analytical requirements, the additional time required could reduce the quality of this and other components of the plan.

Staff suggests it would be difficult to determine whether PGE has met specific requirements if PGE does not provide an energy analysis conducted at the hourly granularity. However, Staff does not explain why an hourly timestep is the appropriate unit of time for this modeling. While PGE agrees there are likely benefits to increasing granularity in its modeling (having identified this as a limitation in the March 2023 Roundtable meeting), PGE is unsure why the hourly timestep (and not any other) is the most appropriate for CEP/IRP analysis. Even after determining appropriate modelling resource allocation, PGE has concerns that many analytical difficulties are present when evaluating a model using an hourly timestep, as it

[112] LC 80 Round 1 Comments of Staff at 8-11
[113] LC 80 Round 1 Comments of RNW at 20-21 & 30

could potentially miss additional sub-hourly granularity and potentially lead to model overfitting.[114,115]

These concerns aside, PGE agrees with Staff that evaluating the resources included in the Preferred Portfolio in the PZM model (conducted in Aurora) could provide useful insight into both the feasibility of our plan and opportunities for modeling improvements going forward.[116] While the iGHG model was an important step in the development of this IRP (as it allowed for an appropriate accounting of emissions consistent with DEQ emission methodologies), there were many simplifying assumptions therein that should be tested and understood.

Inputting the set of resources contained in the Preferred Portfolio into the PZM and evaluating the hourly system position highlights the differences in estimating the dispatch of existing thermal resources. In the filed CEP/IRP the iGHG model separates the total thermal generation estimated in the PZM model into energy used to serve retail load and wholesale market sales. It does so on a yearly basis relying on the yearly plant average CO_2 intensities prescribed by the ODEQ for emissions reporting. However, as currently constructed the PZM uses thermal characteristics used in the MONET model, which include a minimum, maximum, and average heat rate for each unit.[117] The main question in this analysis is whether PGE is planning for sufficient non-emitting generation to meet emission reduction targets, and these differences prevent any direct comparisons between the emissions results from the PZM and iGHG model. However, by examining the expected hourly energy generation some insight can be gained into the limitations of PGE's current analytical approach. PGE interpreted Staff's draft analysis to be using this same approach.[118]

It is reasonable to expect differences when using the results from a longer timestep analysis in one that is shorter; judgment is needed to determine whether those differences are acceptable. When considering the hourly energy load-resource balance from a set of

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[114] An hourly could miss sub-hourly granularity. For example, if a generation resource disproportionately generates in the last 15-minutes of an hour, an hourly analysis could determine that the company was energy sufficient while operationally needing more generation resources. PGE does not believe the potential availability of the EIM could address these differences and/or mitigate concerns about the emissions implications of PGE's position.

[115] The CEP/IRP PGE uses individual generation shapes for incremental resources to provide the general characteristics of what can be expected on an average basis from the resource. The uncertainty in those shapes is important to consider. It would be inappropriate to believe that they forecast that for example at 2pm on August 3rd a SE Washington wind resource will be generating precisely 7.59% of its nameplate capacity, despite the shape identifying that production. Similarly, building a load-resource balance for that specific hour would put increasing reliance on that input; doing so could be informative, but the costs (measured in over-fitting analysis and time not doing other modeling) could also outweigh its benefits.

[116] For this analysis the Preferred Portfolio from the July 7th Addendum is used, though correcting for the 7 MWa underestimation of energy need mentioned below in **Section 6.2.4**.

[117] While emission rates could be adjusted to align the PZM with DEQ emission rates, PGE has believed there is benefit to retain the operational detail contained in the PZM (and MONET), accepting the resulting differences in emission forecasts.

[118] Assigning a positive market emissions rate for all hours in which PGE was short and then adding those emissions to the emissions associated with retained thermals and carbon content of market purchases.

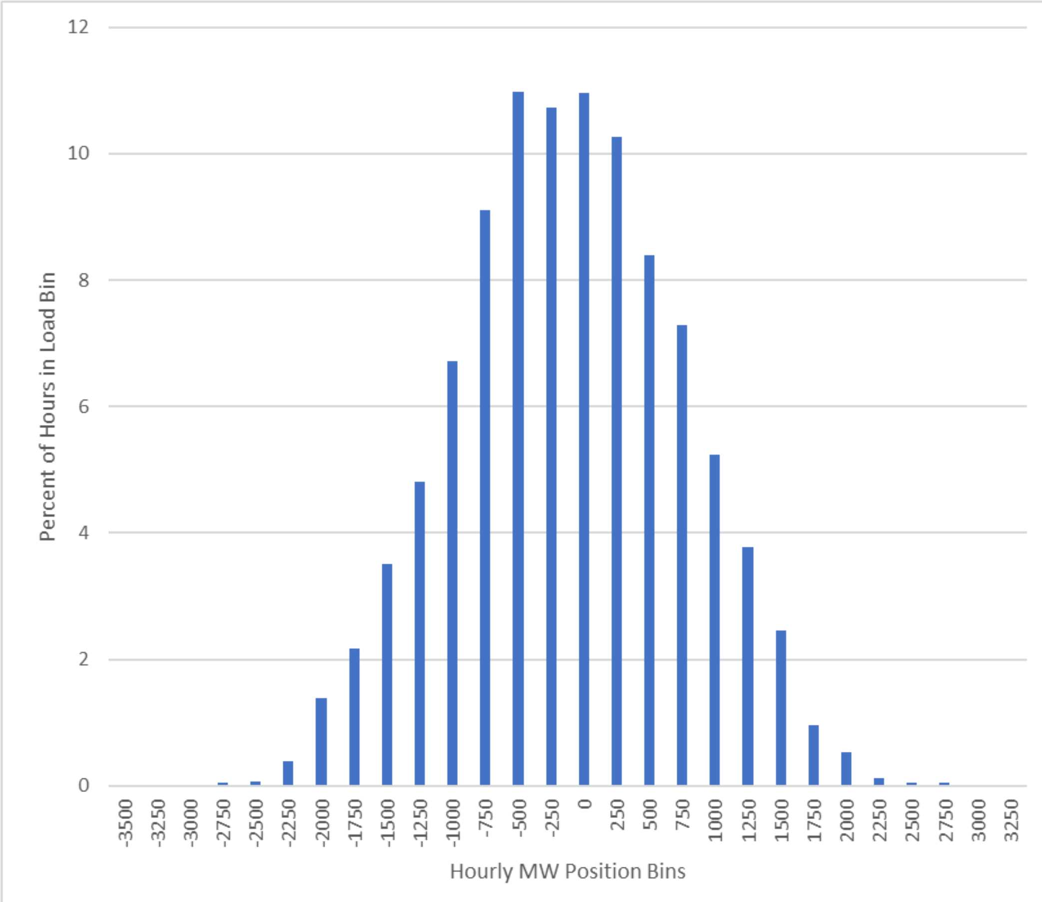
resources that are balanced at the yearly level, the difference between load and generation in each hour represents how long or short the company's expected generation is relative to its demand. These differences can be analyzed across different dimensions. Ideally, the distribution of those differences is symmetric and centered at zero (signifying on average a balanced system) with a variance within an acceptable level (suggesting sufficient market depth to cover the hours where the company is short). Additionally, in an ideal scenario there would be no seasonality (or other temporal influence) of that distribution.[119,120]

While the PZM estimates total economic dispatch of thermal units, the relevant question is whether PGE is sufficient using only generation kept for retail load. A challenge in this analysis is determining how that generation (as well as the assumed emitting net-market purchases) are allocated over the year. Using only economics to determine the timing of that generation (as well as all other PZM assumptions) and adding market purchases evenly throughout the year, the distribution of market position hours appears on average adequate (on average ~9 MWa long), with a standard deviation of ~858 MW. This distribution (displayed below in **Figure 4**) suggests a general agreement between the PZM and ROSE-E, the latter of which selected the set of resources in the Preferred Portfolio to meet that average demand.

[119] For example, if all hours where the company were short occurred around February and August (two months of higher market prices), this would suggest a difficulty in those times to procure sufficient non-emitting generation on the market and accordingly a difficulty in meeting emission reduction targets (as the company would be forced to procure energy with associated emissions).

[120] Market prices are another consideration. A best-case scenario would be if the company was forecast to be long (and short) in periods of high (and low) market prices.

Figure 4. Initial distribution of energy position hours



While the confirmation of model estimation is encouraging, it does not by itself address Staff's concern that focuses specifically on the emissions implications of short hours. Before addressing this though it is useful to consider two questions posed by this initial naive analysis concerning the allocation of generation with associated emissions.

> *Should the thermal generation associated with retail load be used in hours in which PGE is already long?*
>
> There are 2,752 hours in the analysis above in which PGE is long before thermal generation, and in 362 of them thermal resources are generating due to the relative economic and operational forces in those hours. Since this generation is designated for serving retail load it makes sense in this analysis to reallocate that ~148 GWh to hours in which PGE is estimated to be short. However, the operational constraints that are a feature of the PZM complicate this analysis. It is not straight forward to simply limit thermal generation in hours of sufficiency while maintaining the desired generation levels, especially in the short timeline provided in LC 80. This is a critical area of development for PGE, as understanding how emission and operational

constraints interact (especially under forecast uncertainty) will be necessary to develop a resource plan that maximizes reliability and power costs while meeting emission reduction targets. For this analysis PGE considered a variety of outboard heuristics (described below) that achieve the goal of reallocating that generation but miss the operational detail available in Aurora. The company will prioritize this work as it continues to develop its modeling capabilities.

How should emitting market purchases be distributed across the year?

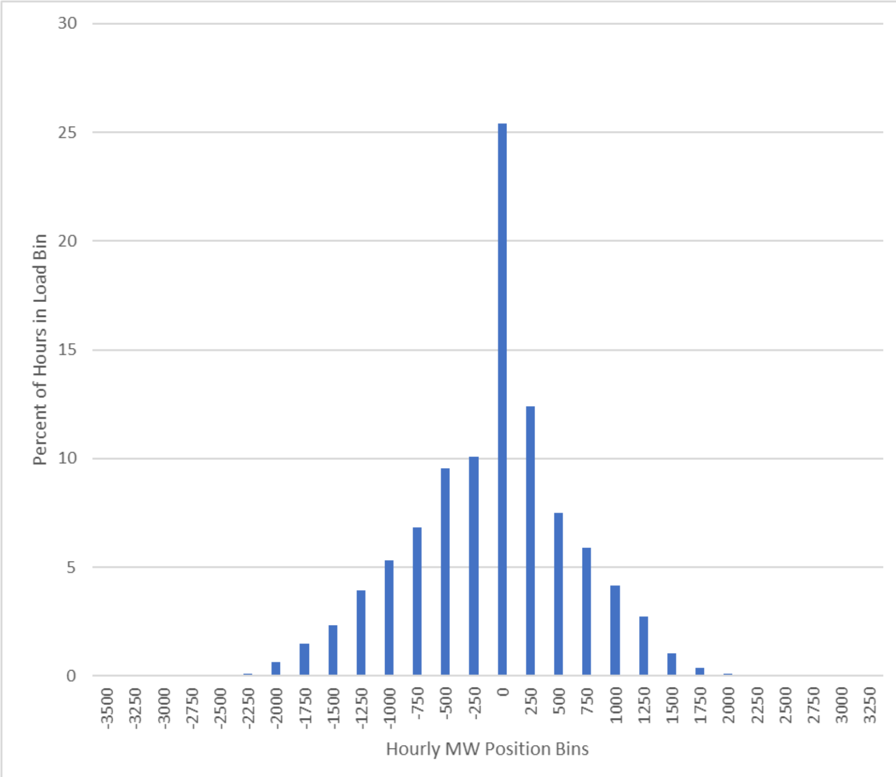
Market purchases with associated emissions are determined by the iGHG model and based on historical purchase levels, historical ratios of energy retained for retail load service, and the relevant emissions glidepath.[121] The above distribution allocated those 1,465 GWh equally across the year (adding 167 MW in each hour). However, it is reasonable to assume that those market purchases with associated emission would not occur in hours in which the company was long. There are a variety of methods to allocate these purchases: size or timing of the short position, market prices (high or low), known peak times, operational experience, etc. PGE evaluated several below, but determining the most appropriate methods will be foundational to understanding how PGE can use the market to address intermittent generation.

One approach to address the questions above would be to sum the total generation in long hours with the total market purchases and redistribute it across hours in which PGE was short.[122] Doing so while following Staff's assumption that non-emitting generation can be purchased in hours in which market prices were non-positive leads to the histogram of energy position hours displayed in below. Noting the y-axis differences between **Figure 4** above, **Figure 5** below displays the increase in the number of hours in which PGE is perfectly balanced (as the thermal generation in otherwise adequate hours is moved to short hours).

[121] PGE used this approach in the CEP/IRP as it is based on historical data and consistent with our treatment of energy and emissions of PGE owned resources.

[122] As noted above, ideally this would incorporate operational constraints modeled in the PZM as not all thermal generation can be moved from long to short hours. However, given the limited time available for these Reply Comments this redistribution is done outboard, and accordingly misses some operational fidelity that otherwise would be expected using Aurora. This might not be an unreasonable simplification, as the thermal generation in this analysis is only that associated with thermal load. There is expected additional thermal generation (for wholesale sales), and the ability to change from market sales to retail load is very likely much more agile than the operational constraints of an individual unit. For example, while a thermal likely cannot generate 100 MW in one hour than 50 MW the next, PGE likely can run the plant in both hours at 100 MW and sell 50 MW in the second hour.

Figure 5. Revised histogram of energy position hours



Another approach would be to instead move the excess thermal and market generation to short hours with higher market prices.[123] Assuming higher market prices signify a lower availability of non-emitting generation, allocating the market generation to higher-priced hours would minimize the likelihood that PGE would be reliant on market purchases with associated carbon content. The resulting distribution of energy position hours is displayed below in **Figure 6**. It shows a larger number of hours where PGE is perfectly balanced than above, and an uneven distribution between short and long hours. This further highlights the importance of understanding the conditions of hours where PGE is short.

[123] Reallocating this generation leads to hours where PGE is forecasted to be long. For example, instead of allocating 50 MW to an hour that PGE was short by 20, that excess 30 MW could be reallocation to a different hour. This process is repeated once in the results that created **Figure 4**, but in Excel it could be continued further resulting in fewer shorter hours and more balanced hours. The operational considerations mentioned above limit the usefulness of this formula-based approach.

Figure 6. Reallocating generation and market purchases to above-average priced hours

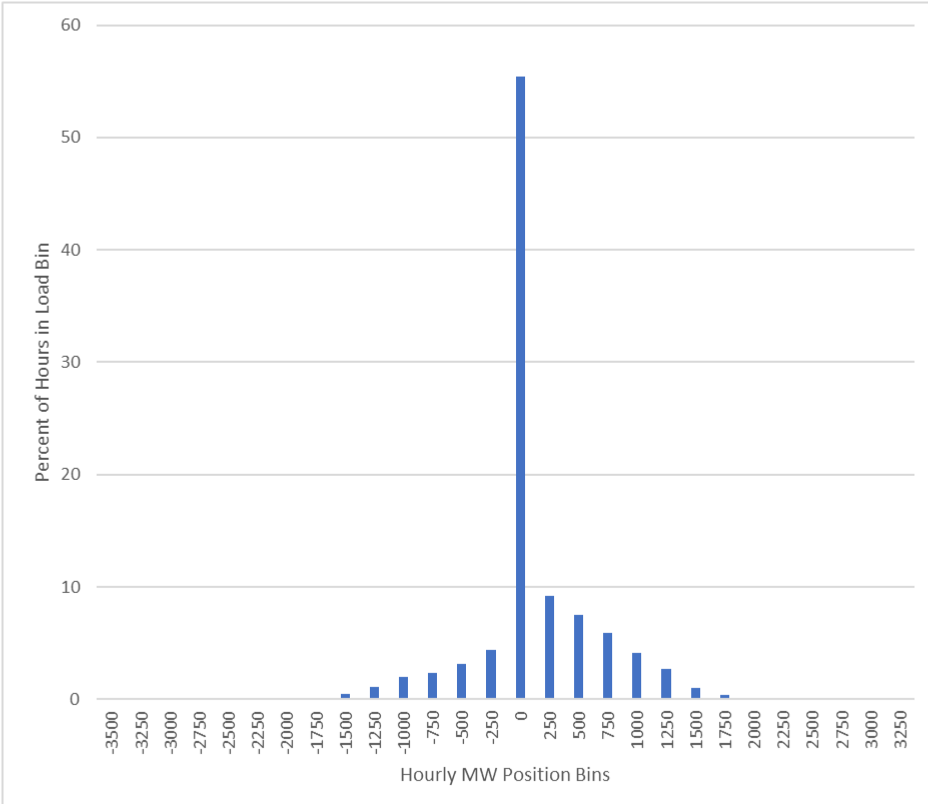
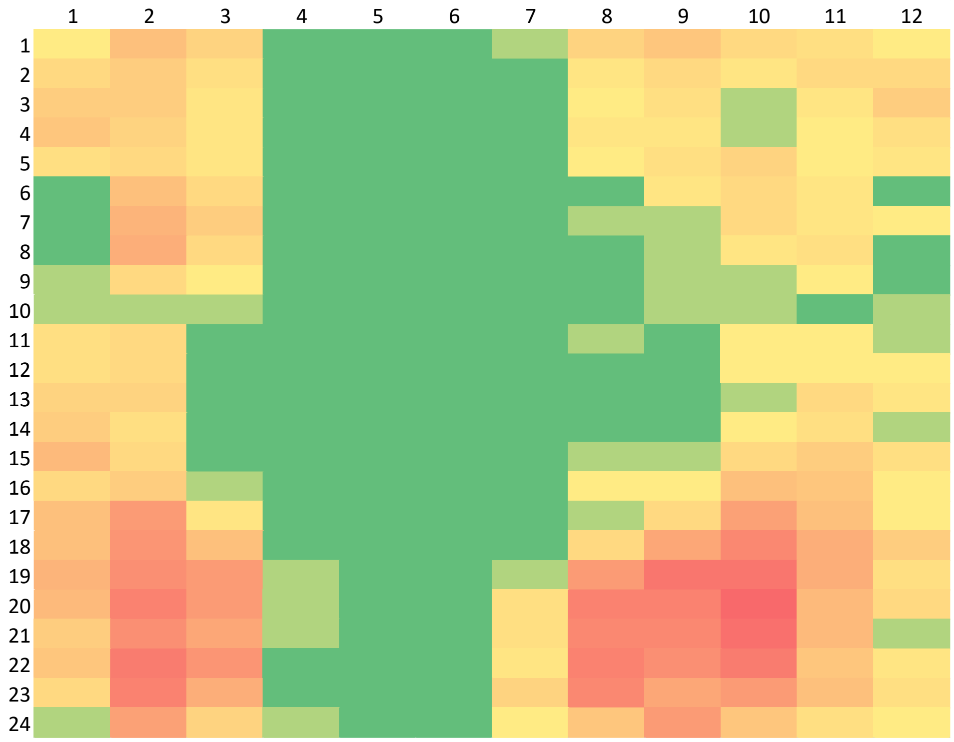


Figure 7 below is a 12x24 heatmap that displays the count of hours where PGE is estimated to be short under the scenario described above.[124] This heatmap is notably different than that describing capacity need, which shows need in peak hours.

[124] While this figure does not display the size of those impacts, a figure that instead displayed the average sizes of shortness rather than the count appears very similar.

Figure 7. 12x24 heatmap of number of short hours in expected average conditions



There are additional considerations that PGE is investigating through this work. Currently, battery storage systems are modeled to pursue energy arbitrage: the storage will charge at the lowest price hours and discharge at the highest price hours. Storage resources are limited to charge and discharge 365 times a year. While only focusing on economics, the storage operation assists PGE's energy position by assuming a strong negative correlation between PGE's energy position and market prices (being long when market prices are low and vice versa). However, this correlation is likely not perfect, and it seems likely that changing the orientation of battery storage to move energy more directly from hours of surplus to hours of deficit would reduce the number of hours estimated to be short. Similarly, specifying the behavior of hybrid resources could be influential to results. Currently the PZM operates hybrids like equivalently sized stand-alone solar and storage resources, but there are some situations where this will not be the case.[125] Resource adequacy modeling also is directly relevant for this evaluation. PGE followed direction from both Staff and the Commission that capacity in the CEP/IRP should be evaluated under expected weather, plant operations, and hydro conditions (referred to as a C-50 scenario). This choice (adopted by the Commission in Order 22-446) signified that PGE would model resource adequacy under average conditions. Increasing this choice of C-level would also change the quantity of

[125] For example, in the recent solar and storage QF tariff filed in UM 2000 hybrid resources are required to charge their storage using the associated renewable resource and discharge their storage during pre-determined and fixed hours.

thermal generation available for serving retail load and would affect the quantity of hours that PGE is both short and long to the market. Finally, this analysis highlights a need to better understand PGE's approach to determining hourly load. In the modeling process employed in both the 2019 IRP and the 2023 IRP/CEP, PGE applies an hourly shape to the monthly corporate load forecast to create an hourly load profile. Whether this month-to-hour conversion appropriately captures the expected average variations in demand will be highly influential to results.[126]

Once these methodological questions are settled Staff's main concern can be addressed, as the results described above suggest that it is reasonable to assume that any hourly histogram of hourly energy position would have some hours where PGE is short. The yearly iGHG model in the filed CEP/IRP utilized an assumption that PGE was able to buy (and sell) non-emitting generation at times which it was short (and long).[127] For analysis conducted at a yearly interval this seemed appropriate given the uncertainty involved and the alignment with the yearly timestep of the portfolio analysis model. However, PGE understands Staff's draft analysis to assume no availability of non-emitting generation (save for non-positively priced hours). If this assumption is correct, then both PGE and Staff's draft analysis are in alignment pointing to a need for an increased quantity of non-emitting generation to be acquired between now and 2030 to ensure compliance with HB 2021 under expected average conditions. If it is not, then this analysis indicates that meeting emission reduction targets with the Preferred Portfolio's set of incremental resource additions is possible under expected conditions.

Unfortunately, neither analysis provides sufficient insight into the availability of a market for non-emitting generation. PGE's simulated market prices are extremely sensitive to the resource buildout employed. Following the 2019 IRP, the WECC-wide model was based on a forecasted set of resource additions created by the consultancy WoodMac which is based on projections of technology, demand, and relevant policy. However, unlike the previous IRP PGE did not evaluate different resource buildouts. Understanding the differences across a range of WECC resource buildouts (and the resulting effects on forecasted market prices) will be critical going forward to understand the potential for PGE to lean on the market under times of lower intermittent generation. Further, the critical takeaway from this work would be an understanding of the availability of non-emitting generation, which will require a better analysis of market demand as well. It is and will continue to be an area of active exploration for PGE.

[126] One additional consideration evaluated by Staff was PGE's choice of which thermal generation to retain. PGE does not believe this is an appropriate sensitivity as it would select generation most favorably for the Company (akin to the resource 'shuffling' mentioned unfavorably by RNW) and does not represent a realistic operational strategy when existing thermals are expected to be utilized for maintaining resource adequacy on PGE's system.
[127] Further, this assumption stated that the benefit from the sales equaled the cost of purchasing the non-emitting generation.

The 2023 CEP/IRP took major steps to modify its modeling process to better align with the emissions accounting methods employed by the ODEQ. Those emissions methodologies are long standing, serve as the basis of the state's GHG policy and goals, and now have the added advantage of requiring independent third-party verification. PGE notes however that given the accelerated complexity of long-term planning, the increasing number of topics of interest, and increased expectations from stakeholders and the Commission, there are very few areas of analysis in the filed CEP/IRP that cannot be improved. However, while PGE agrees that much work is needed to better understand the dynamics of expected generation, emissions, and market interactions, the Company disagrees that Staff cannot verify whether PGE's plan meets the expectations set forth in ORS 469A.420(2) and in Order No. 22-446. PGE believes it does, with the caveat that all results are based on its current long-term modeling process. This caveat is critical, and suggestive of the need for PGE to continue to invest in the development of its emission accounting process and assumptions about market availability. Temporal granularity will be an integral component of both. Considering these uncertainties, PGE is less confident than Staff that an hourly timestep (and not say a sub-hourly or monthly approach) is the most appropriate level of detail required to create a long-term plan with significant policy and economic uncertainty, finite modeling resources, and competing questions of interest. However, PGE is eager to work with Staff and stakeholders to work on these questions as we continue the improvement of our modeling process for this and future regulatory proceedings.

4.7.2 Ancillary services

RNW expresses concerns that PGE may be underestimating GHG emissions from the existing thermal fleet associated with operating to provide ancillary services because of lack of temporal granularity in current modeling. RNW says that PGE should analyze the ancillary services role currently served by its thermal fleet and identify the investments necessary to reduce reliance on thermal resources for voltage, frequency, inertia, and other power flow requirements.[128]

PGE's response

As noted in **Sections 4.5.1, Sub-annual emissions modeling** and **4.7.1, Hourly analysis of the Preferred Portfolio**, PGE agrees that there are limitations associated with the temporal granularity of our current modeling capabilities and is committed to taking steps to improve our capabilities in the future. Additionally, PGE agrees with RNW that there is a significant need to improve PGE's modeling of its need for ancillary services. PGE identified these limitations and expressed the goal to improve our capabilities in the future in March 2023

[128] LC 80 Round 1 Comments of RNW at 25 & 29-30

roundtable meeting. As we note in **Section 4.7.1**, we believe that despite the need to continue to improve our modeling capabilities, the modeling in the CEP/IRP demonstrates a resource acquisition strategy that allows us to comply with HB 2021 emissions requirements.

Chapter 5. CBRE and CBIs

5.1 Informational CBIs

RNW and Energy Advocates recommend the inclusion of actions that focus on environmental and energy justice within PGE's Action Plan. Additionally, both stakeholders reiterate their preference to be able to differentiate CBI progress resulting from CEP-driven actions as distinct from other actions taken by PGE. [129,130] Relatedly, Staff notes that it is unclear how several CBI categories are directly impacted by CEP/IRP analysis and encourage PGE to make stronger linkages going forward.[131]

Several parties provide feedback on the specific CBIs included in PGE's list of iCBIs. Staff, Energy Advocates and RNW all reiterate previous recommendations concerning environmental iCBIs and reflection of tribal priorities in iCBIs. Staff offers more detailed considerations to improve clarity and usability of certain CBIs.[132] And RNW expresses a desire to learn more on any work PGE has conducted to date to establish iCBI baselines.[133]

CUB expresses desire to further understand how the CEP/IRP were in the public interest, as it relates to environmental and health benefits, and reliability and resiliency of the system.[134]

PGE's response

The 2023 CEP/IRP represents PGE's first attempt at including informational CBIs (iCBIs). The development and integration of CBIs within portfolio analysis occurred within a short period of months given the timing of finalized regulatory expectations and plan filing dates. PGE is therefore still learning and should be able to create a stronger understanding between actions taken and the reported iCBIs as we evolve.

CEP/IRP actions represent broad resource needs and targets. Specific actions that impact customers including EJ communities occur downstream during program planning and resource procurement. For example, the CEP/IRP actions state the targets to procure CBREs

[129] LC 80 Round 1 Comments by Renewable Northwest at 52
[130] LC 80 Round 1 Comments by Energy Advocates at 14
[131] LC 80 Round 1 Comments by Staff at 16
[132] Id.
[133] LC 80 Round 1 Comments by Renewable Northwest at 52
[134] LC 80 Round 1 Comments by CUB at 6

but not specific CBRE project proposals. Hence the effectiveness of those CBREs in mitigating energy burden or providing resiliency will be established through the resource acquisition process. Thus, PGE does not believe it is appropriate to include specific iCBIs as actions within the Action Plan in this CEP/IRP.

Regarding the attribution of actions to CBI progress, PGE 's approach in the CEP/IRP, through our engagement processes, was to prioritize and select accessible but necessarily broad iCBIs. PGE believes this approach aligns with the intent of the CEP expectations and is consistent with feedback provided by Energy Advocates in the UM 2225 process. An implication of this approach is that CBIs will be impacted by a myriad of factors both within and out of scope of CEP/IRP actions, and even the scope of utility actions. PGE is open to trying to isolate the impact of its CEP actions, once the iCBI approach is formalized through the acknowledgement of the CEP/IRP, on the iCBIs but believes the broad nature of the iCBIs may hinder our ability to isolate the impact of CEP actions from other factors that impact iCBIs, including other company actions.

PGE appreciates the reiteration by stakeholders to include an environmental iCBI and an iCBI specific to tribal communities and hopes to dispel the Energy Advocates' perception that PGE is resistant to consideration of this suggestion. PGE does not currently have the capacity to engage with communities to inform development of specific environmental and tribal iCBIs for this CEP/IRP. However, PGE will develop iCBIs in both areas by working with stakeholders including the community, to review prospective iCBIs including those listed by stakeholders in these comments before determining which environmental and tribal iCBIs are most appropriate to include and track in the next planning cycle. PGE will consider including these new iCBIs as part of reporting in the next CEP/IRP.

Regarding iCBI baselines, though some data may be available or tracked and reported for other purposes, PGE has not begun an analytical process to develop baselines for iCBIs. Following OPUC acknowledgement of our CEP/IRP, PGE intends to begin the work of specifying iCBI data sources and developing baselines.

Addressing CUB's comments, PGE notes that emissions reductions achieved by our CEP/IRP actions will contribute to public health and environmental benefits across our state and region. Furthermore, projects deployed through implementation of CBREs and customer actions have high potential to provide very localized health and environmental benefits. Rather than define and estimate the value of each potential benefit area in advance, we intend to use the CBI process to provide a snapshot of these benefits over time and use input from community groups to inform areas of high importance to focus on. PGE has accounted for these benefits in a generalized approach via both rCBIs and pCBIs. PGE chose this approach to ensure the CEP/IRP balances the time available to meet these requirements along with an approach that is not overly prescriptive and enables downstream resource procurement to consider a wide range of options. Regarding iCBI development, PGE worked with communities to prioritize the list of iCBIs, as described in CEP/IRP Section 14.2.3.2 CBI community engagement. We expect the iCBI list will be a primary input within downstream procurement activities, where further community engagement will influence how these iCBIs factor into resource acquisition process.

PGE's approach to reliability and resilience has been informed by communities through PGE's DSP process, OPUC's UM 2225 process, and Learning Labs prior to the CEP filing, as detailed in the CEP/IRP Chapter 13. Resilience is a broad objective, with implications on numerous aspects of PGE's planning and operations. PGE has taken significant steps to consider resilience within the scope of this CEP/IRP and we expect our approach to continue to evolve and mature moving forward. The inclusion of resilience-focused iCBIs and our commitment to use CBIs to inform resource acquisition decisions for CBRE resources and customer programs are ways in which the CEP/IRP will ultimately affect customer and community resilience.

5.2 CBRE community engagement

On the topic of CBREs and community engagement, RNW reiterates their Round 0 comments identifying a need for more capacity building and resources in under-resourced communities for them to gain experience and an ability to engage in planning and building CBRE projects.[135]

PGE's response

PGE appreciates RNW's acknowledgement of the Company's plans to engage community members and other environmental justice representatives in the development of the CBRE acquisition process and scoring matrix. We expect CBRE acquisition to be an iterative process. PGE is looking to work with Staff and other stakeholders to define the best way to pursue the additional capacity building and resources needed to gain experience in these under-resourced communities. Ultimately, PGE views this as a collaborative process that will help in identifying the best way to build these capabilities.

5.3 Maximum CBRE Potential

Related to the topic of CBREs, Energy Advocates requests additional explanation surrounding how PGE determined 155 MW as the maximum amount of realistic and achievable CBRE potential in the Action Plan.[136]

[135] LC 80 Round 1 Comments by RNW at pp. 53
[136] LC 80 Round 1 Comments by Energy Advocates at pp. 9

PGE's response

PGE conducted a community lens potential study (described in Section 7.2 of the CEP/IRP) that identified 155 MW of technical achievable CBRE potential for inclusion in portfolio analysis in this first CEP/IRP. The high-level steps PGE followed to determine this amount for inclusion in portfolio analysis were:

a) Review the literature and past feedback from community participants gathered through the Distribution System Planning process

b) Define the proxy CBRE resource types for inclusion in portfolio analysis (Standalone community-scale solar, community resiliency microgrids, and in-conduit hydro)

c) Develop quantitative assessments leveraging multiple sources, including PGE's AdopDER model, published municipal climate action targets, Energy Trust project pipelines, and published national lab studies such as the Oak Ridge National Lab in-conduit hydropower potential study.[137]

Each resource's MW buildup is generated following this process and represents PGE's best assessment of a realistic and informative CBRE potential, given the specific modeling delineations discussed in Section 7.2 of the CEP/IRP. As PGE gains more experience with these new resource types, we expect to revisit and refine this process (also described in Section 7.2.4 of the CEP/IRP).

5.4 CBRE acquisition

On the topic of CBRE acquisition, AWEC comments that PGE justified the acquisition of CBRE resources using arbitrary and unsubstantiated benefits created by reducing the cost of CBRE resources by 10 percent.[138] They suggest this led to acquiring more expensive resources than required and PGE should leverage its available community solar and distributed energy studies to create a cost reduction for CBRE resources.[139] Additionally, AWEC recommends that PGE's only actions to acquire CBRE resources should be tied to the small-scale renewables requirement set forth in ORS 469A.210.[140] They specifically suggest evaluating biomass resources to meet this mandate as they were previously excluded based on feedback received from PGE's community engagement process.[141] Lastly, AWEC suggests that PGE allocate above-market costs of CBRE resources solely to the communities where the

[137] In-conduit hydropower potential study from Oak Ridge National Lab is available at: https://info.ornl.gov/sites/publications/Files/Pub176069.pdf
[138] LC 80 Round 1 Comments by AWEC at pp. 13
[139] LC 80 Round 1 Comments by AWEC at pp. 13
[140] LC 80 Round 1 Comments by AWEC at pp. 14-15
[141] LC 80 Round 1 Comments by AWEC at pp. 14-15

resources are located, if these resources are selected, until these resources are necessary to meet a statutory or regulatory mandate.[142]

PGE's response

PGE agrees with AWEC that the 10 percent cost reduction value for CBRE resources is essentially arbitrary, which was discussed in more detail in Section 7.1.3 of the CEP/IRP. This value was chosen to serve as a representative of the potential benefits CBRE resources would offer given the lack of availability of better information surrounding specific resource characteristics. Additionally, PGE finds it reasonable to believe that the removal of the 10 percent cost reduction would not have any impact on CBRE resource selection and the resulting portfolio. Accordingly, PGE believes AWEC's concerns to be unsubstantiated based upon current evidence. At this point, PGE is not proposing to apply the 10 percent factor in the context of acquisition of any individual CBRE project, for which more project-specific community benefits would be applicable. PGE notes that HB 2021 defines CBREs in such a way that small scale renewables do not necessarily fulfill the broader goals of CBRE; all CBREs, as applied in PGE's CEP/IRP, are small-scale renewables but not all small-scale renewables are CBREs.

Addressing AWEC's comments on biomass resources, PGE reiterates that community feedback informed the Company's decision to exclude biomass resources. Through a stakeholder and community engagement process PGE received direction that biomass resources should not be considered as non-emitting due to their associated greenhouse gas emissions. Therefore, PGE chose not to include biomass resources as potential options within the IRP portfolio modeling.

5.5 CBRE Trade-offs

Staff requests PGE submit a supplemental CBRE analysis that better addresses the costs and opportunities resulting from offsetting energy generated using fossil fuels with community-based renewable energy required in HB 2021.[143] Additionally, Staff suggests PGE perform additional CBRE portfolio analysis to provide more information surrounding when CBRE additions are no longer low-regrets actions or insights into tradeoffs of different levels of CBREs in the portfolio.[144]

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[142] LC 80 Round 1 Comments by AWEC at pp. 15
[143] LC 80 Round 1 Comments by OPUC Staff at pp. 19
[144] LC 80 Round 1 Comments by OPUC Staff at pp. 20

PGE's response

PGE understands the confusion surrounding the required analysis of the costs and opportunities resulting from offsetting fossil fuel generated energy with community-based renewable energy. Although it was not explicitly stated as fulfilling the HB 2021 requirement, the Company did evaluate the ability of CBRE resources to offset thermal generation. This was not done as an additional independent analysis but instead within the existing portfolio analysis; each portfolio can choose CBRE resources over thermal resources if the capacity expansion model (ROSE-E) determined it was a lower-cost solution. However, the maximum quantity of CBRE resources were generally already selected either based on portfolio construction and/or economics. As stated in Section 11.4.3.1 of the CEP/IRP, the optimized CBRE portfolio selected the full amount of CBRE resources available and had the lowest costs and risks, equivalent to the portfolio forcing the full amount of CBRE resources.

Accordingly, PGE never found an opportunity for CBREs to offset thermal generation due to the simple conclusion that there was never any available CBRE resource beyond that which was selected based on economics. However, PGE notes that in portfolio analysis the Company never saw additional thermal generation curtailed below the specific levels set by the relevant emission reduction glidepath. This indicates that the net costs of thermal generation generally lower the total LCOE available by CBREs (or any other available generation resources), which supports the consistent finding that there are very few opportunities to increase pace of decarbonization while also decreasing costs.

Finally, addressing Staff's request for additional CBRE portfolio analysis assessing different levels of CBRE in the portfolio, PGE is unsure of the added value of evaluating additional CBRE resources past the maximum quantity determined to be available in PGE's Community Lens Potential study. Current portfolio analysis has defined CBRE portfolios evaluating varying levels of CBRE resources within the maximum available quantity. Further work is needed to determine the precise quantity and associated pricing of CBRE resources available, but PGE believes that portfolio analysis is most meaningful when it uses the determined quantity strictly as an input.

5.6 Portfolio CBIs

Staff expresses concern that PGE's current Portfolio CBI (pCBI) approach does not allow comparison of all relevant community impacts and does not have an impact on portfolio selection. To address these concerns, Staff recommends that PGE provide an interim pCBI that captures the different benefits across all resource types across all portfolios. Staff recommends that the quantity of energy efficiency and microgrid CBREs in each portfolio be used as an interim pCBI scoring metric until the PGE can identify more metrics for quantifying important impacts of its potential actions on communities. Staff also recommends that PGE update portfolio scoring to express the pCBI in dollar terms. If the recommended analysis cannot be provided, Staff recommends that PGE discuss opportunities and barriers to meeting the request.[145]

PGE's response

PGE understands Staff's request to be looking to gain more information on the trade-offs between community benefits and costs. While PGE agrees that this is an important dynamic to characterize, portfolio analysis (as constructed) has suggested that maximizing community benefits and minimizing costs involve the same actions. Staff's suggestion of including an interim pCBI that identifies differing levels of community benefits for non-CBRE resources does not seem appropriate at this point because its inclusion would not impact portfolio analysis results and would not provide useful insight without significant input redevelopment and additional methodological refinement.

As noted in **Section 5.1, Informational CBIs**, this CEP/IRP was PGE's first attempt at incorporating CBIs and included an interim approach developed in a short amount of time. PGE has neither the experience nor expertise to meaningfully quantify dollar values for the different benefits different proxy resources (let alone individual projects) may have on communities. PGE does not believe it can develop these estimates with any precision in this docket. Furthermore, efforts to assign dollar values to specific benefit streams and apply resulting net benefits to portfolio optimization would have implications for other cost-effectiveness analysis overseen by OPUC, further underscoring the need for a robust process.

Instead of updating portfolio analysis with the pCBI expressed in dollar terms, PGE proposes beginning a process to quantify pCBIs and incorporate them into portfolio analysis by holding workshops with a third-party mediator to elicit stakeholder input and engaging a consultant with the necessary expertise to develop a more sophisticated approach. The Company will work with Staff and stakeholders to create this process going forward.

Chapter 6. Portfolio analysis

6.1 CBREs & DERs

Energy Advocates recommends that PGE run a model sensitivity with a higher adoption of CBRE and distributed-generation resources (DERs), specifically requesting that PGE model a portfolio that results in selection of 125 percent of the maximum stated CBRE potential used in portfolio analysis.[146] In a similar comment, NewSun requests analysis of additional quantities of CBREs, suggesting that PGE has not adequately addressed CBRE technical

[145] LC 80 Round 1 Comments of Staff at 15-16
[146] LC 80 Round 1 Comments of Energy Advocates at 9

achievable potential and requesting modeling of either an uncapped quantity of CBREs or up to 125 percent of the potential that PGE assumed in portfolio modeling.[147] NewSun also suggests PGE should run a model for DERs up to their achievable potential.[148]

PGE's response

The quantity of DERs and CBREs made available for selection in portfolio modeling was determined based on PGE's expectations about the availability of those resources.[149] As noted above, PGE does not believe conducting analysis on quantities of DERs and CBREs greater than are expected to be available would produce an actionable portfolio or offer particularly meaningful informational value. Accordingly, PGE is prioritizing other analyses for these Reply Comments.

Regarding CBREs, analyzing quantities beyond what is expected to be available would only provide value to the extent that the potential study is inaccurate. Results from the filed CEP/IRP and the Addendum showed that selection of the full amount of CBREs available reduces portfolio costs. Given the transmission and emissions constrained modeling environment, it is reasonable to expect that further analysis in which additional quantities of CBREs were available would find that selection of the incremental CBREs would further reduce portfolio costs. PGE believes upcoming efforts to acquire CBREs will provide important insights into their costs and availability that can be incorporated into future planning.

Regarding modeling of additional quantities of DERs, portfolio analysis in the CEP/IRP and Addendum has already shown that not all DERs made available to the model are selected, so making more available beyond the quantity used in modeling is not necessary. Specifically, 100 percent of non-cost-effective demand response is available and never selected, and less than 100 percent of EE is selected when available, so making additional quantities of either available would not change portfolio results.

6.2 Model specifications

6.2.1 Need Futures

Energy Advocates asks for clarification on where analysis of High and Low Need Futures can be found.[150]

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[147] LC 80 Round 1 Comments of NewSun at 9-10
[148] LC 80 Round 1 Comments of NewSun at 10-11
[149] See **Section 5.3, Maximum CBRE Potential** for CBREs and PGE's DSP for DERs.
[150] LC 80 Round 1 Comments of Energy Advocates at 10

PGE's response

The list provided by Energy Advocates in their comments shows the set of 40 portfolios analyzed in the CEP/IRP. Each of the 40 portfolios is modeled across three Need Futures (Reference, High, Low). Need futures describe forecasted system need under a range of assumptions about load growth, distributed energy resources and market assumptions.[151,152] They are used in portfolio analysis to determine the robustness of proposed resource additions to a range of potential energy and capacity need conditions. For simplicity and clarity, the results that PGE has presented and described in previous IRPs, this CEP/IRP, and the July 7th Addendum mainly focus on the Reference Need Future, though resource buildouts and resulting costs are available for each need future and can be provided if helpful.[153]

6.2.2 Colstrip exit

Energy Advocates recommends that PGE model early Colstrip retirement in 2027 and modify the Action Plan accordingly.[154] Energy Advocates claims that keeping Colstrip in the portfolio will result in an underinvestment in clean energy. This reasoning is based on a dispute with PGE's modeling approach in which all else equal, Colstrip's presence in the portfolio reduces the amount of GHG-emitting energy that can be retained for retail sales. Energy Advocates cites the costs associated with complying with the EPA's proposed Mercury and Air Toxics Standards (MATS) as a factor that will drive early shutdown of the plant. Similarly, Staff states that it is unclear whether the inclusion of Colstrip in the portfolio beyond 2025 appropriately balances cost, risk, the pace of GHG reductions, and community impacts because no early exit portfolio was analyzed.[155]

PGE's response

PGE owns a minority 20 percent share in Colstrip Units 3 & 4 and cannot act unilaterally on operational decisions or the exit/closure of either Colstrip unit. The potential impacts of regulatory actions such as MATS on the outcomes of the plant do not change this. As a result, a portfolio in which Colstrip exits the portfolio prior to 2029 would not be considered actionable by PGE. For IRP planning purposes, PGE makes the modeling assumption of continued off-taking of power from Colstrip 3 & 4 through 2029. If a decision is made by all

[151] Portfolio analysis evaluated portfolios across a range of 351 total future scenarios based on the combinations of 3 futures for need, 13 futures for price, 3 for hydro condition, and 3 for technology cost.
[152] For addition description of Need Futures, see Section 4.2 of the 2023 CEP/IRP. Available at: https://edocs.puc.state.or.us/efdocs/HAA/lc80haa8431.pdf
[153] Portfolio analysis outputs provided in LC 80 AWEC DR 039 Attachment B contains results for all three Need Futures, for all portfolios.
[154] LC 80 Round 1 Comments of Energy Advocates at 13
[155] LC 80 Round 1 Comments of Staff at 11

Colstrip parties that results in a planned shutdown prior to 2029, PGE will update modeling assumptions regarding the plant accordingly.

From a modeling perspective, when Colstrip is removed from the intermediary GHG model PGE can retain more energy from emitting resources (because of the lower emissions rates of natural gas plants), which reduces the need for energy from incremental non-emitting resources in those years. The Action Plan annual acquisition target is based on the year 2030 energy need, which does not include Colstrip. While removing Colstrip early may impact portfolio analysis it will not impact Action Plan acquisition recommendations and it would therefore not provide useful information to guide decision-making about resource acquisitions at this point.

6.2.3 Clean capacity glidepath

In related comments, RNW and Staff express concern with risk associated with the rate of capacity additions in the Preferred Portfolio. RNW suggests PGE incorporate a clean capacity glidepath within portfolio modeling to smooth the transition away from GHG-emitting resources in the portfolio and prevent the risk of "hockey stick" transitions in resource additions at critical milestones.[156] Staff expresses concern with large capacity additions being made in the years leading up to the large increase in capacity need that occurs in 2040. Staff recommends that PGE provide additional analysis that decreases the annual capacity limit imposed in portfolio modeling to explore the cost and risk implications of spreading the additions of capacity to meet 2040 needs across more years.[157] Staff also asks that PGE explain how the capacity additions in the Preferred Portfolio have informed the long-term decarbonization strategy as it relates to acquiring non-emitting capacity over time.[158]

PGE's response

PGE's portfolio analysis smooths the addition of resources to prevent unrealistically large and risky resource additions (the 'hockey stick' effect described by RNW) in the key target years of HB 2021 GHG emissions reduction goals.

This is done in two ways. First, the linear decarbonization glidepath necessitates that renewable resources be added to offset GHG-emitting generation continually throughout the planning horizon. While the driver of these resource additions is energy need rather than capacity need, they do provide capacity and represent not insignificant additions of capacity. This contrasts with the back-loaded emission pathway which lowers quantified portfolio cost and risk metrics by delaying resource additions to the end of the decade. Second, an annual

[156] LC 80 Round 1 Comments of RNW at 29-30
[157] LC 80 Round 1 Comments of Staff at 25-26
[158] LC 80 Round 1 Comments of Staff at 27

build limit of 500 MW is placed on the generic capacity and VER resources in portfolio modeling after 2031 to smooth out resource additions and prevent very large resource additions from happening in a single year to meet the large increase in capacity need in 2040.[159]

Tightening the annual build limit on the generic resources would not change the overall quantity of resources needed but would result in a resource buildout that is shifted forward in time and spread out across more years. The change in timing of resource additions would produce two competing effects on portfolio risk. It would reduce unquantified procurement and non-compliance risk by increasing the buffer between when resources are added and when they are needed for compliance but would also increase quantified portfolio cost and cost-risk due to declining cost curves and discounting. PGE will seek to balance the tradeoffs between these multiple sources of risk in our procurement strategy between now and 2040.

6.2.4 Offshore wind in Preferred Portfolio

RNW and Deep Blue Pacific Wind suggest that the Preferred Portfolio should include offshore wind because offshore wind is part of the least-cost and least-risk portfolio.[160] [161] RNW presents results from a supplemental offshore wind report PGE conducted at the request of the Oregon Department of Energy (ODOE) and Staff as evidence that offshore wind is a least-cost resource that should be included in the Preferred Portfolio. RNW claims that the IRP does not test the economic value of offshore wind because it was not evaluated under appropriate and comparable conditions because the offshore wind portfolio in the IRP cannot be compared to portfolios containing transmission expansion.[162] RNW also presents results from alternative portfolio analysis which they conducted that makes offshore wind available in the Preferred Portfolio and shows it offsetting other resources, claiming that it makes a more interesting and relevant comparison.[163] RNW recommends that PGE include at least 1 GW of offshore wind in the Preferred Portfolio.[164]

PGE's response

PGE agrees that offshore wind represents an attractive potential resource to meet our needs if it becomes available for acquisition. This is highlighted in the results of our supplemental offshore wind report, which shows the usefulness of up to approximately 2.8 GW of offshore wind additions. Results of the Preferred Portfolio from PGE's Addendum to the 2023 CEP/IRP

[159] The 500 MW annual limit does not have a binding effect on resource additions until 2036 for generic VER and 2038 for generic capacity.
[160] LC 80 Round 1 Comments of RNW at 37-38
[161] LC 80 Round 1 Comments of Deep Blue Pacific Wind at 10-11
[162] LC 80 Round 1 Comments of RNW at 34-35
[163] LC 80 Round 1 Comments of RNW at 38-39
[164] LC 80 Round 1 Comments of RNW at 32

also demonstrate the large potential role for offshore wind using generic resources, with over 5.7 GW of generic VER resources added through 2043, some or all of which could be filled by offshore wind. However, there are real concerns that this total quantity would realistically all be delivered to PGE alone.

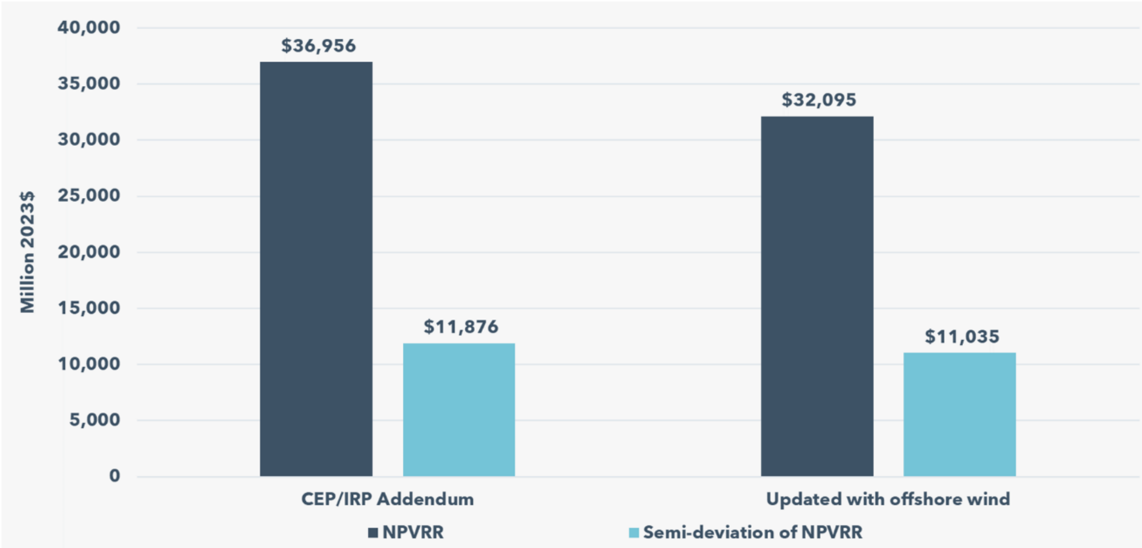
While PGE disagrees with RNW's suggestions that the results from either their own analysis or PGE's supplemental offshore wind study should determine the composition of the Preferred Portfolio, we understand that making offshore wind available in the Preferred Portfolio may offer increased clarity on the fact that PGE views it as a valuable potential resource to help meet our forecasted large resource needs, if it becomes available.[165] Consistent with RNW's recommendation, PGE has conducted new analysis and updated the Preferred Portfolio to include access to 1000 MW of offshore wind beginning in 2032.[166] Results from the new Preferred Portfolio show that all 1000 MW of available offshore wind are added by 2037 (**Table 7**). The most notable impact to the resource additions of the Preferred Portfolio is a reduction in reliance on generic resources. The total amount of generic VER added through 2043 decreases from 5756 MW to 4326 MW, with the total amount of generic capacity decreasing from 2043 MW to 1818 MW. While the full 800 MW of transmission expansion is still added in the portfolio, the timing changed, with the addition of some NV Solar and transmission expansion being delayed. As a result, the total amount of transmission expansion added through 2030 decreases by 74 MW to 726 MW.

Figure 8 shows the difference in portfolio cost and risk metrics between the Preferred Portfolio from the filed Addendum and the new Preferred Portfolio, which includes 1000 MW of offshore wind. The offsetting of a substantial amount of generic resources with offshore wind resulted in a decrease in portfolio NPVRR of approximately $4.86 billion.

[165] PGE's modeling approach is not predicated upon the comparison of the Preferred Portfolio against other portfolios, as described in **Section 6.3, Preferred Portfolio**.

[166] The updated analysis also includes the correction of a minor error present in portfolio analysis in the Addendum to the CEP/IRP. While in the filed Addendum PGE describes an update to the energy accounting methodology to start accounting for the 7 MWa of negative energy associated with battery storage in PGE's portfolio, the associated impact was omitted from the energy need value used in portfolio analysis. The effect was that resources of the Preferred Portfolio in the Addendum were based on a slightly smaller energy than they should have been.

Figure 8. Cost and risk metrics of the Preferred Portfolio



The cumulative resource additions from 2024-2030 in the updated Preferred Portfolio are shown in **Table 5** (offshore wind is not visible in this table because it is not available until 2032).

Table 5. Cumulative resource buildout in Preferred Portfolio

	2024	2025	2026	2027	2028	2029	2030
Wind	0	0	708	1108	1128	1528	1528
Solar	0	0	0	0	0	176	326
Hybrid	0	0	298	298	890	1010	1010
Battery Storage	0	0	0	0	0	0	0
Pumped Hydro Storage	0	0	0	0	0	0	0
Offshore Wind	0	0	0	0	0	0	0
CBREs	0	0	66	85	110	133	155
WY Tx	0	0	0	0	0	400	400
NV Tx	0	0	0	0	0	176	326
Generic VER	0	0	0	0	0	0	331
SoA Tx	0	0	0	400	400	400	400
Additional EE & DERs	0	0	0	0	0	0	0
Non-GHG-Emitting Contract Extension	0	0	200	200	200	200	200
Cost-effective EE (MWa)*	30	60	90	120	150	183	216
Cost-effective DR*	133	162	183	199	211	218	228

	2024	2025	2026	2027	2028	2029	2030
Clearwater Wind **	311	311	311	311	311	311	311
Seaside Storage **	0	0	200	200	200	200	200
Troutdale Storage **	0	200	200	200	200	200	200
Evergreen Storage **	0	75	75	75	75	75	75

* Contributions reduce need
** 2021 RFP resources

Table 6 provides an update of Table 2 from the filed CEP/IRP, providing a summary of total resource actions from 2023 through 2030, showing incremental new resources added by year (it does not show resource losses). It includes the IRP Preferred Portfolio resources and non-CEP/IRP resource actions (2021 RFP resources, qualifying facility resource additions, GFI solar additions, etc.).[167] **Table 6** also includes PGE's retail load service GHG emissions glidepath from 2023 through 2030.

Table 6. Preferred Portfolio resource pathway through 2030 (incremental additions)

Values in nameplate MW	2023	2024	2025	2026	2027	2028	2029	2030
DR (cost-effective)	24	26	25	19	14	11	8	9
EE (cost-effective)	31	30	30	30	30	31	33	33
Storage	0	0	275	200	0	0	0	0
Solar & wind	30	734	69	718	410	30	586	491
Offshore wind	0	0	0	0	0	0	0	0
Hybrid	0	0	0	298	0	592	120	0
CBRE	0	0	0	66	19	25	23	22
Transmission (Tx) market access	0	0	0	0	0	0	576	150
Contract extension	0	0	0	200	0	0	0	0
GHG glidepath (MMTCO2e)	5.9	5.3	5.0	4.4	3.7	3.0	2.3	1.6

Table 7 shows incremental resource actions from year 2031 through 2043. It also includes PGE's retail load service GHG emissions glidepath from 2031 through 2043.

Table 7. Preferred Portfolio resource pathway 2031-2043 (incremental additions)

Values in nameplate MW	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
DR (cost effective)	11	8	9	8	5	11	7	7	7	1	6	11	3

[167] As a result of including non-CEP/IRP and non-RFP resources the values in this table will differ from those in **Table 6**. For simplification purposes, generic VER resources and 5 MW of qualifying facility biomass are included in the wind & solar values.

Values in nameplate MW	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
EE (cost effective)	34	34	32	31	29	28	25	23	19	16	15	11	9
Storage	0	0	100	100	100	100	100	100	100	2100	0	0	0
Solar & wind	522	0	0	0	7	500	500	500	500	574	483	258	225
Offshore wind	0	237	235	253	252	0	23	0	0	0	0	0	0
Hybrid	0	0	0	0	0	0	0	0	0	0	0	0	0
CBRE	0	0	0	0	0	0	0	0	0	0	0	0	0
Tx market access	0	0	0	0	0	0	0	0	0	74	0	0	0
Capacity	0	0	0	0	27	119	172	500	500	500	0	0	0
GHG glidepath (MMT CO2e)	1.5	1.3	1.1	1.0	0.8	0.6	0.5	0.3	0.2	0.0	0.0	0.0	0.0

6.2.5 Clarity on post-2030 resources

RNW suggests that the Preferred Portfolio should contain specific resources rather than generic resources.[168] They present an alternative Preferred Portfolio developed using their own assumptions that reduces the reliance on generic resources by allowing the model unconstrained access to offshore wind and WY and NV transmission expansion resources. RNW presents results showing that using these assumptions produces lower portfolio costs than those associated with PGE's Preferred Portfolio from the filed CEP/IRP Addendum.[169] RNW suggests that this provides clarity on post-2030 resources and sends better market signals to developers.[170]

PGE's response

PGE agrees that a plan with more clarity on the mix of post-2030 resources would send a better market signal to developers and as noted in **Section 6.2.4, Offshore wind**, we have amended the Preferred Portfolio to include access to 1000 MW of offshore wind beginning in 2032. We disagree however, that all resources in the portfolio need to be specific to be informative. PGE does not have the ability to predict the full set of resources that will be available throughout the planning horizon, and this reality is the driver behind a key modeling paradigm used in portfolio analysis; there are no specific resources modeled in the IRP. All resources in IRP portfolio modeling are proxies, including the generic resources. Generic resources are just proxies defined with less-specific characteristics than the traditional set of proxy resources. Given the uncertainty about resource availability, proxy

[168] LC 80 Round 1 Comments of RNW at 41
[169] LC 80 Round 1 Comments of RNW at 32
[170] LC 80 Round 1 Comments of RNW at 40-41

resources provide a reasonable modeling construct to represent the wide range of potential specific resources that may become available and to send market signals at an appropriate level of specificity.

PGE made the modeling choice to rely on generic resources to meet the majority of post-2030 energy and capacity needs because of uncertainty in the availability of emerging resources. There are many potential resource options that may become available to fill the need met by generic resources in the Preferred Portfolio. Just as the use of proxies for resources like onshore wind and solar does not represent a lack of interest in any specific projects that may become available, the use of generic resources does not signal a lack of interest in any specific resource; rather it represents an openness to all variety of resources that may become available without claiming an unfounded level of certainty which resources will emerge as viable options. However, PGE anticipates working with RNW and other stakeholders in future planning cycles to determine the most appropriate method to model potential resources in a way that considers the increased levels of uncertainty in the later years of the planning horizon.

PGE also disagrees with RNW's logic that the lower NPVRR of their portfolio makes it the Preferred Portfolio. The generic resources which are offset in RNW's portfolio were designed to be expensive relative to the proxy resources and it is logical that portfolio costs will decrease when less of the generic resources are added. The Preferred Portfolio was hand designed based on analysis of key questions as well as the imposition of constraints designed to produce a portfolio that accounts for the reality of PGE's system and planning environment. This is illustrated through the fact that PGE analyzed portfolios throughout the course of portfolio analysis that produced lower NPVRR than the Preferred Portfolio, such as one that did not impose any transmission constraints. However, such a portfolio does not represent an outcome that PGE views as realistic or a portfolio that is actionable. Comparison of scoring metrics of all types, including NPVRR, must be made with consideration for the broader analysis approach and judgement used to determine their application in determining the composition of the Preferred Portfolio. Finally, PGE notes that RNW's suggestion of allowing uncapped access to transmission expansion is contrary to the suggestion by Staff that transmission expansion be excluded from the Preferred Portfolio (see **Section 6.3, Preferred Portfolio**).

6.2.6 Conditional firm transmission and ELCCs

RNW suggests that PGE should modify the ELCC analysis to conform to their suggestions for modeling conditional firm transmission.[171]

[171] LC 80 Round 1 Comments of RNW at 51

PGE's response

As described in **Section 2.2, Conditional firm transmission modeling**, PGE disagrees with RNW's recommendation for modification to assumptions about modeling of conditional firm transmission. Accordingly, PGE does not think it is reasonable to conduct portfolio analysis using ELCCs that do not differ between firm and conditional firm resources as their proposed methodology would suggest. Doing so would result in higher ELCCs for conditional firm resources, decreasing the resulting resource build required to meet capacity needs and producing an inadequate portfolio in the face of contractual transmission impacts.

6.2.7 Transmission avoidance

Staff is concerned that the CEP/IRP is undervaluing on-system capacity resources that can reduce transmission congestion.[172] Staff suggests that in PGE's modeling, while on-system resources that provide energy like CBREs and EE allow the avoidance of transmission upgrades, capacity-only resources like storage and DR cannot help avoid transmission upgrades because they do not help to meet GHG targets. Staff asks PGE to adopt, for the next CEP/IRP, a transmission modeling approach that considers the ability of on-system capacity resources, like batteries or DR, to alleviate transmission congestion and thus avoid transmission upgrades and associated costs.

PGE's response

While PGE will continue to improve aspects of our transmission modeling approach, we disagree that portfolio analysis in the CEP/IRP does not account for the ability of on-system capacity to alleviate transmission congestion or capture the value they provide by avoiding transmission costs. There are two reasons that this is the case. First, because off-system renewable resources are added to meet both energy and capacity needs, on-system capacity resources can still help avoid or delay off-system renewable resources if they are being added for their capacity contribution. Second, HB 2021 GHG emissions targets create both energy and capacity needs, as demonstrated by the large increase in capacity need in 2040 when a 100 percent GHG-emissions reduction is required. The large additions of capacity resources in the Preferred Portfolio are driven by HB 2021 GHG targets just as the large additions of renewable resources are. Therefore, in addition to being able to avoid the addition of off-system renewables which provide both energy and capacity, the value of on-system capacity resources is also captured by their ability to offset additions of the generic capacity resource, which represents any number of potential types of resources, including access to capacity resources enabled by new transmission. Because generic capacity was designed to be slightly more expensive that the costliest proxy resource (NV solar and

[172] LC 80 Round 1 Comments of Staff at 35

transmission expansion), the ability to offset additions of generic capacity captures substantial value in portfolio modeling.

6.3 Preferred Portfolio

Staff recommends that PGE re-design and re-evaluate the Preferred Portfolio without assuming up to 800 MW of transmission expansion access. Staff suggests that the availability of these options should be considered as a scenario or sensitivity instead. Staffs suggests PGE should analyze a large set of alternative portfolios that test varying paces of GHG reductions and varying community benefits in a way that can be directly compared to the Preferred Portfolio.[173]

PGE's response

PGE's approach to portfolio analysis was designed to test specific questions about key topics such as GHG emissions trajectories, transmission, CBREs, and DERs. This was done using groups of portfolios, within which portfolios were designed to be compared against one another. As discussed in **Section 6.4, Scoring metrics**, evaluating all potential combinations of portfolios is unfeasible and unnecessary to gain insights about key questions posed in this CEP/IRP. Additionally, PGE notes that the acknowledged 2019 IRP also used a 'hand-designed' approach to creating a Preferred Portfolio and that the comparability of the Preferred Portfolio to other portfolios is neither an IRP guideline nor requirement.

The insights from the evaluation of portfolios within key portfolio groups were used to inform the creation of the Preferred Portfolio. The tradeoffs of varying paces of GHG reduction was explored in detail in the decarbonization portfolio group, with the linear-glidepath found to provide the best balance of rate of emissions reduction with cost and risks. Similarly, analysis within the transmission portfolio group highlighted the large need for both transmission upgrades and expansion to bring needed energy from new renewables, both within and outside of the PNW, to PGE's load. The addition of transmission expansion was also found to reduce portfolio costs. Guided by these insights, PGE decided that transmission expansion was an important component of the Preferred Portfolio and believes it would be inappropriate to exclude it. PGE also notes that the suggestion by Staff to remove the 800 MW of transmission expansion from the Preferred Portfolio runs contrary to the suggestion by RNW (described in **Section 6.2.5, Clarity on post-2030 resources**) that the Preferred Portfolio be allowed access to uncapped amounts of transmission expansion.

However, to explore the impact of Staff's suggested change to the Preferred Portfolio, PGE conducted new analysis for these Reply Comments, modeling the Preferred Portfolio from the Addendum with the 800 MW of transmission expansion removed. This was done to test

[173] LC 80 Round 1 Comments of Staff at 24

the effect of the change requested by Staff only and is for informational purposes only. The resulting portfolio produced a $4.32 billion increase in costs compared to the Addendum Preferred Portfolio (**Figure 9**). The resource buildout through 2030 in the new no transmission expansion portfolio is shown in **Table 8**.[174] Without access to the transmission expansion, the portfolio produced several notable differences in resource buildout. Most notably, the portfolio has increased reliance on both generic capacity and generic VER. Although not shown in **Table 8,** the first year of generic capacity addition shifted forward from 2034 to 2031 and the total amount added increased from 2043 MW to 2716 MW. The first year of addition for generic VER shifted forward one year from 2030 to 2029 and total additions increased from 5756 MW to 6555 MW. Additionally, while the total amount of battery storage added did not change, the first year of addition also shifted forward, from 2032 to 2030. The quantity and timing of additions of pumped hydro did not change.

Figure 9. Cost and risk metrics of the Preferred and no transmission expansion portfolios

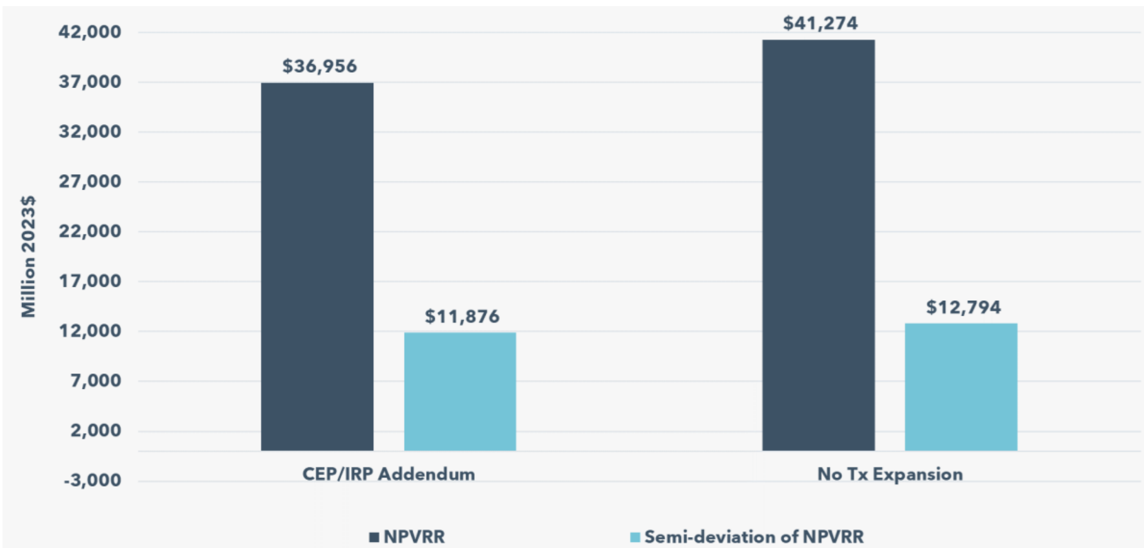


Table 8. Cumulative resource buildout in no transmission expansion portfolio

	2024	2025	2026	2027	2028	2029	2030
Wind	0	0	690	1090	1128	1128	1128
Solar	0	0	0	0	0	0	0
Hybrid	0	0	299	299	873	1010	1010
Battery Storage	0	0	0	0	0	0	341
Pumped Hydro Storage	0	0	0	0	0	0	0
Offshore Wind	0	0	0	0	0	0	0

[174] **Table 8** shows resources added in PGE's capacity expansion model, ROSE-E, only. It does not include the 2021 RPF resources or cost-effect quantities of DERs shown as part of the Preferred Portfolio in **Table 5**.

	2024	2025	2026	2027	2028	2029	2030
CBREs	0	0	66	85	110	133	155
WY Tx	0	0	0	0	0	0	0
NV Tx	0	0	0	0	0	0	0
Generic VER	0	0	0	0	0	594	1064
SoA Tx	0	0	0	400	400	400	400
Additional EE & DERs	0	0	0	0	0	0	0
Non-GHG-Emitting Contract Extension	0	0	200	200	200	200	200

6.4 Scoring metrics

Staff has several recommendations on the topic of portfolio scoring metrics. Staff suggests that PGE should adopt a scoring metric for the pace of GHG reductions to show the tradeoffs between cost, risk, the pace of GHG reductions, and community impacts and benefits across portfolios and suggest PGE consider use of the Social Cost of GHGs to contextualize tradeoffs between portfolios.[175] Staff also suggests that PGE should design a scoring metric for near-term cost impacts that can be applied across all portfolios and justify its use in planning and procurement decisions.[176] Staff suggests that PGE does not use portfolio scoring consistently across all portfolios, resulting in a sub-optimal quantity of EE in the Preferred Portfolio.[177] Finally, Staff recommends that in the future, PGE should justify portfolio analysis findings and design principles used to develop the Preferred Portfolio based on all scoring metrics, not just those that address cost and risk.[178]

PGE's response

PGE believes Staff is being overly prescriptive in this recommendation. There are many ways to design portfolio analysis; while it is up to the Company to justify why results from portfolio analysis are in the long-term interest, it's appropriate to consider portfolio analysis using all applicable methods, not just uniform scoring metrics. For example, as noted above in **Section 6.2.3, Clean capacity glidepath**, PGE used the unquantifiable procurement risk to not favor the back-loaded decarbonization glidepath. PGE notes that using scoring metrics for specific decisions (like near-term costs or GHG reductions) is not required by IRP or CEP guidelines. PGE believes that Staff should not require this specific modeling approach to determine whether the Company's portfolio analysis is appropriate.

[175] LC 80 Round 1 Comments of Staff at 25
[176] LC 80 Round 1 Comments of Staff at 25
[177] LC 80 Round 1 Comments of Staff at 5
[178] LC 80 Round 1 Comments of Staff at 25

While PGE looks forward to working with Staff and stakeholders in the next IRP to refine our portfolio modeling approach, we are confident in the appropriateness of the approach employed in this CEP/IRP, which is designed to focus effort on the most pressing planning questions in the face of a rapidly evolving planning environment that presents many new challenges. The structure of our portfolio analysis allows the evaluation of the trade-offs and implications of GHG emission reductions and to determine an appropriate approach to EE in the Preferred Portfolio.

As mentioned in **Section 6.3, Preferred Portfolio**, PGE's portfolio analysis approach does not rely on evaluating every possible combination of portfolio options. Evaluating scoring metrics across all portfolios is not necessarily useful. For example, evaluating the near-term costs of an offshore wind portfolio against a CBRE portfolio does not provide insightful information to guide the creation of the Preferred Portfolio. Comparing the near-term costs across all portfolios is also not informative because near-term costs are an issue specific to EE and the near-term cost implications of varying levels of EE addition can be compared within the EE portfolio group. There are no other portfolios where the near-term costs implications are different than their long-term cost metrics. Similarly, the pace of GHG reductions only needs to be compared within the decarbonization group of portfolios because that is where those tradeoffs are being analyzed. Further, it is not feasible to compare all combinations; there are seven EE and eleven transmission portfolios, to evaluate all combinations of each would produce 77 portfolios.[179]

Regarding the optimal quantity of EE in the Preferred Portfolio, as noted in **Section 6.2.5, Clarity on post-2030 resources**, the fact that adding a resource to the Preferred Portfolio may lower NPVRR does not necessarily indicate that it must be included to produce an optimal outcome. Multiple criteria, considering both quantifiable and unquantified sources of risk, are considered in the designing the Preferred Portfolio. In the case of EE, the near-term cost impacts associated with EE were deemed too risky to warrant its inclusion in the Preferred Portfolio at this time despite the potential long-term cost benefits.

6.5 Supply-side options

6.5.1 Pumped hydro

Swan Lake and Goldendale suggests that the assumption of a 38-year useful life used in PGE's derivation of pumped hydro cost estimates is too short and requests that Staff direct PGE to re-run portfolio analysis using a 50-year life and evaluate a 75-year sensitivity. Swan

179 Extending this logic further, adding in the five CBRE, five decarbonization, four optimized, two targeted-policy, and six emerging technology portfolios would create 92,400 portfolios. It is obvious that some judgment is needed to determine which set of portfolio choices are appropriate to model.

Lake and Goldendale suggests that PGE was incorrect in the claim that a 38-year useful plant life assumption was supported by a study conducted by the engineering firm HDR.[180]

PGE's response

The Preferred Portfolio from PGE's Addendum to the CEP/IRP show a need to acquire over 4.8 GW of capacity resources by 2043. This includes 2 GW of pumped hydro storage added in 2040. This represents a very large amount of capacity resources and demonstrates PGE's interest in resources that can help fill this need. As with all resources modeled in the IRP, the pumped hydro storage resource is a proxy resource, designed to represent a range of potential projects that may become available for acquisition. This concept is discussed further in **Sections 6.2.4, Offshore wind** and **6.2.5, Clarity on post-2030 resources**. The unique operational and cost characteristics that distinguish specific projects from one another will be considered in the analysis of actual projects if they submit bids to an RFP.

PGE notes the HDR narrative discussion cited by the Projects. However, the 38-year useful life assumption came from quantitative data provided by HDR in Excel format for input to PGE's models in the 2019 IRP analyses. For these Reply Comments, PGE conducted new analysis to compare the cost differences that result from changing the assumption of useful life from 38 years to 50- and 75-year life. Results show that a change in useful life from 38 years to 50 years results in approximately an 8 percent reduction in the levelized fixed cost and a change to 75 years results in an additional 7 percent reduction. These values assume the same construction costs are incurred upfront, the same annual fixed costs occur annually, and no incremental capital expenditures are required to support a longer useful life.

To test the robustness of portfolio analysis results to changes in the cost assumptions of pumped hydro storage, PGE conducted additional new analysis modeling the Preferred Portfolio from the Addendum using 15 percent lower fixed costs for pumped hydro storage. Testing a decrease in costs consistent with the longest useful life suggested by the Projects, PGE found no impact on resource additions compared to the use of PGE's cost assumption. Just as when using PGE's cost assumption, derived using a 38-year useful life, all 2000 MW of available pumped hydro are added in 2040. The cost test resulted in no change to the resources in the Preferred Portfolio in the Addendum, demonstrating the robustness of portfolio analysis results to the changes in plant life assumptions suggested by the Projects. Therefore, PGE does not believe that re-running all of portfolio analysis with alternative plant life assumptions for pumped hydro would be informative.

[180] LC 80 Round 1 Comments of Swan Lake and Goldendale at 2-4

6.5.2 Offshore wind

RNW disputes PGE's characterization of offshore wind as an emerging technology.[181] They cite over 200 MW of floating offshore wind in operation globally today and projections for large increases by 2027. RNW also claims that the costs included in the IRP for commercial operation dates after 2030 PGE are conservatively high, suggesting that PGE appears to not be fully accounting for all the factors considered by NREL, such as either the geographic specificity of southern Oregon or the changes in cost over time.[182]

PGE's response

PGE stands by its characterization of offshore wind. While it offers attractive characteristics, there are currently no offshore wind facilities in Oregon and much remains to be developed before the offshore wind can be assumed to be available to provide energy for PGE's customers. The transmission requirements noted in **Section 2.1, Comprehensive transmission comments** describe several challenges in both transmission and interconnection that need to be addressed before PGE can procure energy from an offshore generator. This characterization does not change that fact that, as described in **Section 6.2.4, Offshore wind**, PGE has a large resource need and represents a very interested potential buyer of the resource if it becomes available and has updated the Preferred Portfolio to include 1000 MW of offshore wind.

Given the lack of existing offshore wind in Oregon, the estimates of costs are naturally uncertain. A number of factors can explain the majority of difference between PGE's and NREL's LCOEs:

- PGE costs are presented for 2030 COD while NREL's costs are provided for a 2032 COD. Costs for a later COD are expected to be lower than an earlier COD. A lower overnight capital cost will result in a lower LCOE, all else equal.
- PGE's LCOE is reported in 2023 dollars while NREL's report provides values in 2019 dollars. Adjusting for four years of inflation results in relatively higher costs.
- PGE's resource costs use the projected utility cost of capital (including capital structure, costs of equity and debt, and tax rates). NREL uses a capital structure more heavily weighted towards debt financing, resulting in a lower cost of capital and lower cost of ownership.
- PGE's modeling resulted in an approximately 55 percent capacity factor for the Southern Oregon offshore wind site; this compares to the 57 percent stated in the

[181] LC 80 Round 1 Comments of RNW at 40
[182] LC 80 Round 1 Comments of RNW at 39

NREL report. A relatively higher capacity factor results in more assumed energy generation and a lower LCOE (where annual energy generation is the denominator).

- In total, these adjustments result in an approximately $3/MWh (5 percent) difference remaining between PGE and NREL.

Chapter 7. Request for proposals

7.1 CBREs

PGE received comments regarding CBRE acquisition strategy from Staff and Energy Advocates. On this topic, Staff poses several questions.[183] First, Staff asks if PGE plans to pursue CBRE technologies beyond the proxy resource types included in the CBRE potential study. Second, Staff asks what PGE's strategy is to balance CBRE acquisition costs while maximizing community benefits; specifically considering strategy to leverage funding resources and other partnerships, and key emerging risks and decision points. Third, Staff asks what steps PGE can take to overcome implementation risks and ensure that company resources associated with CBRE procurement activities are used effectively. Energy Advocates suggests that PGE's CBRE actions should go beyond an RFP to include additional approaches to acquire CBREs that are unlikely to bid into an RFP due to the resources required to submit a bid.[184]

PGE's response

PGE anticipates pursuing CBRE technologies beyond the proxies modeled in the IRP. The proxy resources were designed based on their existence on the grid today, meaning that we could better estimate cost and availability for the purpose of forecasting CBRE. The technologies available in the market include distributed solar paired with storage, but PGE is open to any technology type provided it complies with the CBRE definition in HB 2021 and provides value to the grid.

PGE anticipates that an RFP structure for CBRE resources would only begin the process to meet the targets identified in the CEP/IRP. If the market response to an RFP is sufficient in both volume and benefit, PGE may pursue those projects. If an RFP is unable to provide the volume and benefit expected, PGE will continue to move forward complementary processes to identify resources that may otherwise not choose to bid into an RFP-like structure. Because there are substantial unknowns about the potential costs, we will use the RFP process to learn

[183] LC 80 Round 1 Comments of Staff at 20-21
[184] LC 80 Round 1 Comments of Energy Advocates at 15

and iterate. PGE plans to leverage other funding; federal, state, and local dollars are being directed to support this kind of projects.

PGE believes that maximizing community benefits is important but is also subjective at this point and we are working to make sure our approach aligns with the CBI work to date and continued conversations with stakeholders via CBIAG, learning lab and other advisory groups. We look forward to working with Staff and stakeholders in the coming months to share a set of minimum criteria that will identify how projects can demonstrate grid value. CBRE acquisition represents a clear opportunity to both take action that affects EJ communities and leverages PGE's current capabilities. Additionally, as we continue to develop capabilities around outreach, engagement, and quantification of CBIs, we will explore EJ-specific actions in future CEP/IRP filings.

7.2 Procurement levels

In related comments regarding PGE's procurement strategy Staff recommends that PGE provide additional detail on proposed RFP framework and describe how PGE will respond if an RFP does not result in its targeted procurement level. Staff is specifically interested in detail about PGE's methodology to update the needs assessment, potential offramps, and the process for determining when to close one round of procurement and begin another. Staff also asks how procurement activities will inform other resource actions. Staff suggests that PGE provide regular updates to LC 80 participants on target procurement volume for the 2023 RFP as new information and analysis become available.[185]

PGE's response

PGE filed a planning and procurement forecast in Docket No. UM 2274 on July 17, 2023. PGE's proposed framework includes proposed methodologies for how needs identified in the planning environment should be acted upon, as well as the pace and cadence of future resource acquisition.[186]

PGE's intent with proposing additional bid windows is to alleviate the pressure that would accompany an RFP that is unable to deliver sufficient energy and capacity within the Action Plan window. The ability to re-issue a call for bids under a previously approved structure to recover from a lackluster response would serve as a significant benefit.

Over time, if a lack of market depth was persistent and PGE's ability to procure resources sufficient to maintain continual progress to decarbonize, those results could feed into future

[185] LC 80 Round 1 Comments of Staff at 39-40
[186] See PGE's Planning and Procurement forecast posted to UM 2274 at: https://edocs.puc.state.or.us/efdocs/HAD/um2274had162126.pdf

planning processes in the form of greater reliance on demand-side resources or more specific actions toward non-RFP procurement.

7.3 Scoring

Energy Advocates suggests that the scoring criteria for RFPs should include CBIs or other non-price factors to maximize benefits for environmental justice communities.[187]

PGE's response

PGE acknowledges Energy Advocates' recommendation and their recognition that PGE has proposed community benefits criteria as RFP scoring criteria in the past. PGE looks forward to continued collaboration with stakeholders in future RFPs to determine which scoring criteria provide the least-cost, least-risk outcomes for customers given the resource mix and grid need at the time.

7.4 Timing

7.4.1 Portfolio analysis results

Staff asks if the RFP pacing and supply chain analysis provide quantitative insights into resource acquisition pacing options and whether PGE plans to constrain annual RFPs to match the annual RFP scenario energy and capacity additions.[188]

PGE's response

Results from the RFP size and pacing and supply chain analyses provide insights into the costs and risks of alternative procurement cadences but do not contain exact quantitative recommendations for annual procurement quantities. As described in **Section 7.2, Procurement levels**, PGE's filed planning and procurement forecast in Docket No. UM 2274 provides PGE's proposed framework for the pace and cadence of future resource acquisition. The RFP size and pacing sensitivity illustrates that ability for annual procurement to decrease portfolio costs by more precisely matching the timing of resource additions to needs compared to less frequent acquisitions that add resources in advance of need. The supply chain sensitivity meanwhile demonstrates the potential for supply chain disruptions to increase the cost and risk of resource procurement and highlights the tradeoff between cost risk and compliance risk. While delayed resource acquisition can reduce costs due to

[187] LC 80 Round 1 Comments of Energy Advocates at 15-16
[188] LC 80 Round 1 Comments of Staff at 37-39

discounting and declining resource cost forecasts, it increases the risk of not being able to acquire the resources necessary to comply with GHG emissions reduction requirements.

7.5 Long-lead time RFP

RNW and Deep Blue Pacific Wind suggest that PGE conduct an RFP for long lead-time resources in order to send market signals and provide certainty that will encourage development of offshore wind and other long lead-time resources.[189,190]

PGE's response

PGE does not plan to issue a dedicated long lead-time RFP, but notes that the currently proposed 2023 RFP will seek resources with lead times out through 2029. In addition, we anticipate issuing a request for information (RFI), as noted in the Company's May 19, 2023 filing in UM 2274, to better understand technologies, timing, and future development zones for resources that could contribute toward the company's decarbonization trajectory.[191] This RFI will seek to identify resources that could come online later this decade and in the 2030s and will use responses to prepare for future acquisition cycles (both from a market signal perspective and in terms of preparing the grid for new technologies and locations). Additional information on the RFI process will be available later this year.

Chapter 8. Regulatory

8.1 Small-scale renewables requirement

Staff requests PGE provide a more detailed compliance strategy for the small-scale renewables (SSR) requirement, inclusive of PGE's current and forecasted SSR amounts broken down by resource type and strategies to address potential shortfalls, control costs and promote community benefits.[192]

PGE's response

Section 7.2.6 of the CEP/IRP describes PGE's approach to compliance with the small-scale renewables requirement, highlighting the following activity areas: continued engagement with communities to support project development, project development through existing programs including PURPA and CSP, and deployment of new initiatives including new

[189] LC 80 Round 1 Comments of RNW at 43-47
[190] LC 80 Round 1 Comments of Deep Blue Pacific Wind at 8-9
[191] Available at: https://edocs.puc.state.or.us/efdocs/HAQ/um2274haq15385.pdf
[192] LC 80 Round 1 Comments of OPUC Staff at 21

acquisition actions for CBRE and integration of customer resources into the VPP. PGE shares Staff's interest in a SSR compliance approach that controls costs and drives community benefits, and the alignment of CBRE acquisition with SSR compliance reflects that objective.

In response to Staff's interest in PGE's current and projected SSR compliance position, PGE has extracted and summarized CEP/IRP modeling inputs with relevance to SSR compliance, displayed below in **Table 9**. Further context regarding these forecasts can be found in the respective sections of the CEP/IRP and Addendum.

Table 9. Small-Scale Renewables Forecast

Resource Type	Current Capacity per 2023 CEP/IRP	2030 Forecast as updated in CEP/IRP Addendum
Community Solar Program	27 MW	93 MW
PURPA QF < 20 MW	271 MW	281 MW
CBRE	0 MW	155 MW
Customer DERs (AdopDER forecast)	183 MW (not SSR-eligible per Order 21-464)	739 MW of solar 121 MW of storage[193]
TOTAL SSR ELIGIBLE CAPACITY	**298 MW**	**529 - 1,268 MW**

PGE will continue to assess progress and consider potential additional actions as part of the next CEP/IRP cycle. In response to Staff's question regarding "critical dependencies," we note that success is contingent on implementation of the CEP/IRP Action Plan and related regulatory and policy factors, specifically successful acquisition of CBREs and progress in integrating customer-sited resources into our virtual power plant. Increased ability to manage customer solar as a capacity resource in planning and operations will be a key development toward SSR eligibility of some or all customer DERs. This evolution will be enabled by increased DER visibility and control as well as orchestration of solar with storage and load flexibility to provide system and local capacity benefits, which necessitates advancement of PGE's VPP.

8.2 Avoided cost information

In similar comments, both NewSun and OSSIA noted that their interpretation of OAR 860-029-0080(3) requires PGE to provide draft Avoided Costs in the same format as the final form which is required to be submitted within 30 days of the Commission's acknowledge decision.[194,195]

[193] Some or all solar and storage capacity may be actively included in capacity portfolio via VPP and could be SSR eligible
[194] LC 80 Round 1 Comments of NewSun at 13
[195] LC 80 Round 1 Comments of OSSIA at 2

PGE's response

PGE has provided all the elements of the avoided costs within the CEP/IRP consistent with previously acknowledged IRPs and thus, PGE believes it has complied with the intent of OAR 860-029-0080(3). As part of PGE's Round 0 comments, PGE provided details on the different components of the avoided costs.[196]

8.3 RECs

Staff expresses a desire to understand how PGE might realize value from an expected increase in the size of the REC bank through time as the number of RECs produced annually exceed the amount needed for RPS compliance. They note that Commission Order No. 22-446 requests that PGE include information about REC generation and plans for their use. Staff recommends that PGE provide the volume of banked RECs that it anticipates will expire if they are not used over the planning horizon and discuss how it can plan to utilize its banked RECs to benefit customers.[197] Finally, the Green Energy Institute provides recommendations for how PGE can communicate facts to retail customers regarding energy and its GHG content.[198]

PGE's response

The forecasted need to add renewable resources to comply with HB 2021 emissions reductions targets is larger than the forecasted need to meet RPS obligations, which means that the amount of RECs generated is forecast to be larger than the amount needed to comply with RPS obligations. IRP modeling does not explicitly forecast the quantities of RECs that are expected to expire. Instead, IRP modeling incorporates a RPS obligation constraint and forecasted REC generation to ensure that the Preferred Portfolio is compliant with RPS obligations. While IRP modeling is not currently designed to produce the requested detail about the timing of REC retirement vs expiration, a comparison of the RECs forecasted to be generated with the RPS obligation can provide some insight. Using data from the updated Preferred Portfolio (presented in **Section 6.2.4, Offshore wind in Preferred Portfolio**), the total number of RECs generated through the planning horizon are compared against the amount required to be retired to meet RPS obligations. The total number of RECs needed to meet RPS obligations over the 20-year planning horizon is 162,440,558 MWh.[199] The total number of RECs generated over the planning horizon, plus existing banked RECs, is forecasted to be 425,686,387 MWh, not including those expected to be retired for voluntary customer sales. That means that PGE is forecasted to produce an excess of 263,245,829

[196] LC 80 PGE's response to Initial Comments at 60
[197] LC 80 Round 1 Comments of Staff at 22-23
[198] LC 80 Round 1 Comments of GEI at 1
[199] Assuming a 20% reduction in the size of the obligation to account for an assumed use of 20% Unbundled RECs.

MWh of RECs through the planning horizon. RECs generated may either be used for current period compliance, banked for use in future compliance periods, or sold. Additional detail about PGE's REC strategy can be found in PGE's 2022 Renewable Portfolio Standard Implementation Plan (RPIP), filed on December 30, 2021.[200] PGE's next RPIP is due to be filed at the end of 2023. Finally, PGE agrees with GEI that full transparency is needed when communicating statements about its emissions accounting and forecasting, especially with the Company's use of RECs.

Chapter 9. Engagement

9.1 Outreach and engagement

On the topic of engagement, parties asked for more details regarding PGE's plans to connect specifically with community members to offer information on how CEP and IRP projects and programs affect individual customers' lives. One suggestion is to use meeting spaces that are after hours and/or in local communities. Similar to recommendations that were received related to accessibility, parties suggested that PGE should work with the UCBIAG to refine and improve its approach to effectively engaging underserved and EJ communities.

PGE's response

In DSP Part 1 in2021, PGE articulated our vision for leading the clean energy future through collaboration, outreach and engagement with our customers and communities.[201] Our commitment to community engagement and collaboration continues to deepen and evolve as we expand that commitment to other areas of resource planning, including our CEP/IRP. We prioritize cultivating relationships with new and existing communities, especially those from or who represent environmental justice communities. Our community engagement is based on the principle of involving those impacted by decisions, and our guiding principle is "nothing about us without us." We believe that a clean energy future requires a commitment to diversity, equity, and inclusion (DEI) throughout our operations.

One example of PGE's evolving approach to community engagement is the creation of a new Community Engagement team reporting into the Public Affairs organization. This new team will be led by a new senior leadership position – Director of Community Engagement – who will be charged with developing and maintaining a comprehensive community engagement program for PGE with the numerous diverse communities we serve. The new Community

[200] Available at: https://edocs.puc.state.or.us/efdocs/HAA/um2216haa162836.pdf
[201] DSP Part 1, available at: https://assets.ctfassets.net/416ywc1laqmd/i9dxBweWPkS2CtZQ2lSVg/b9472bf8bdab44cc95bbb39938200859/DSP_2021_Report_Full.pdf

Engagement team operating under this director will focus on crafting and implementing strategies that support both PGE's business and the goals and aspirations of communities we serve, particularly those representing underserved or underrepresented populations.

The Community Benefits Impacts and Advisory Group will be facilitated by a new manager of Community Engagement, a member of the new Community Engagement team.[202] We recently launched the inaugural CBIAG with a kickoff meeting in April 2023. PGE has hosted four additional meetings since the kickoff. There are currently 13 members that represent and/or serve environmental justice communities and other underserved groups serving on the CBIAG. There are two open seats remaining that are being held to allow time to identify and work with existing members to close representation gaps. This group will advise PGE on many topics, including the CEP/IRP and we plan to leverage their feedback to guide our engagement activities.

9.2 Tribal engagement

On the topic of tribal engagement, RNW and the Energy Advocates advise PGE to engage tribes in conversations relevant to CEP goals and actions. Both parties request more details on PGE's plan, such as, how the plan will "build awareness, inform and provide learning opportunities to communities" and "increase community participation, including Tribal and EJ communities?" and emphasize the importance of having a tribal representative on the UCBIAG. CRITFC echoes the request for meaningful engagement and offers the recommendations in their '2022 Energy Vision for the Columbia River Basin' as a guide for consideration in the energy transition.[203]

PGE's response

PGE appreciates the importance of meaningful Tribal engagement. We recently hired a Tribal Liaison and our team will be working closely with this person to develop a plan for engaging with Tribes and Indigenous communities that builds on PGE's Strategic Tribal Engagement Plan (STEP).[204] Also, we are actively recruiting for a Tribal representative on the CBIAG.

9.3 Accessibility

On the topic of accessibility, several parties reemphasized the need to improve accessibility of the CEP. The CEP needs to communicate PGE's compliance strategy in a manner that is accessible and meaningful to the communities it serves, particularly those that might be

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[202] For additional information about CBIAG meetings or materials, please refer to the newly launched webpage: https://portlandgeneral.com/about/who-we-are/community/community-benefits-and-impacts-advisory-group
[203] https://critfc.org/wp-content/uploads/2022/09/CRITFC-Energy-Vision-Full-Report.pdf
[204] PGE's STEP is available in **Appendix B: Strategic Tribal Engagement Plan**

affected by future CBRE projects and resource procurement; communicate in terms relevant to their daily lives. Parties recommended that PGE consult with the UCBIAG on tactics to improve accessibility, including publication in multiple languages.

PGE's response

Staff and stakeholders have been consistent and clear in their pursuit of a more accessible CEP/IRP document and process. PGE took steps to achieve the desired level of accessibility and made adjustments during the proceeding to incorporate feedback and improve the process. Some of these steps and adjustments are described below. We are committed to continuing our efforts to deliver materials and events that are accessible and meaningful to the customers and communities we serve. PGE believes it is important to take a step back and work with Staff, stakeholders and our newly formed CBIAG to develop a standard for what "accessibility" means and what actions should be taken to achieve that standard.

During the CEP/IRP process, we made efforts to improve how we share information and provide more materials. For example:

- We created a dedicated webpage for our CEP and IRP;
- We dedicated the first chapter of the combined CEP/IRP to our decarbonization strategies and path to compliance. This was intended to relieve the reader of having to read through the entire length and complexity of the IRP analysis and chapters that support PGE's decarbonization pathway;
- All past materials and recordings from Learning Labs were available on our webpage so users could access at their convenience;
- Based on feedback we heard from our Learning Lab participants, we switched from using Microsoft Teams to host meetings using Zoom. Zoom was helpful in meeting accessibility needs, because it offered live transcripts and closed captions;
- We are working with Staff and stakeholders to design a community meeting that is more accessible – in community members space at a time that does not conflict with daytime obligations;
- We engaged attendees through various methods, including verbal discussions, chat, Mural Board, Q&A sessions, and real-time feedback; and
- We set up a specific mailbox for community inquiries.

For our IRP we improved our webpage to make information more accessible, including publishing IRP data, roundtable materials, Q&A responses, and video recordings. Our indexing system has been updated based on participant input for easier navigation and we committed to adapting our practices to support standardized information reporting for the CEP in the future.

We deeply appreciate the level of participation and interest from stakeholders in this process. It is important that we make the best use of everyone's scarce time and availability. PGE believes that establishing a clearer standard for accessibility will help achieve our shared objectives.

9.4 Feedback

On the topic of feedback, parties reiterated that PGE should more clearly record and communicate what feedback and recommendations were received across all engagement venues, whether that feedback was incorporated into the CEP/IRP, and why. The process for gathering input from communities on the CBIs was a particular point of interest, i.e., understanding who was consulted and how that feedback was used.

PGE's response

In Section 1.3 of PGE's response to the Round 0 comments, we provided a description of how feedback was captured and incorporated throughout the process to develop the CEP/IRP.[205] PGE understands and appreciates the effort required for stakeholders, especially uncompensated EJ stakeholders, to participate in the CEP/IRP proceedings. It is important that we make the best use of everyone's time and availability. PGE believes that establishing a clearer standard for the treatment of feedback will help achieve our shared accessibility objectives. It is necessary at this point to step back and work with Staff, stakeholders and the CBIAG to establish a standard for appropriate, meaningful treatment of feedback.

9.5 Tax incentives and funding opportunities

Stakeholders appreciate that PGE gave descriptions of the federal incentives available to the utility and has considered these cost saving opportunities as PGE makes investments to meet emissions targets. They also are encouraged by our discussion of the Justice40 initiative which requires that certain federal investments result in 40 percent of the benefits flowing to disadvantaged communities.[206] These include investments areas of clean energy and energy efficiency; clean transit; affordable and sustainable housing; training and workforce development; the remediation and reduction of legacy pollution; and the development of critical clean water infrastructure.

Given the critical role that these incentives play in supporting attainment of HB 2021's emissions targets, stakeholders request that the Company file updates on its planning for use of these funds and include analyses of how it expects the 40 percent of benefits will flow to

[205] PGE's response to Round 0 Comments: https://edocs.puc.state.or.us/efdocs/HAC/lc80hac102443.pdf
[206] https://www.whitehouse.gov/environmentaljustice/justice40/

disadvantaged communities. Stakeholders would like to be timely informed of the analyses and strategies PGE employs to maximize the value of federal incentives and how those strategy options meet or exceed the Justice40 benefits goal for disadvantaged communities.

PGE's response

PGE appreciates the feedback from CUB on the federal funding opportunities the company is pursuing. PGE shares the concerns of the US DOE around the need for workforce development to support the clean energy transition and has been pursuing multiple paths with other stakeholders to ensure the needed workforce is available in Oregon.

Recognizing the need for a collective effort to build an equitable and inclusive workforce that is adaptable to meet the needs of today and in the future, PGE convened the Oregon Clean Energy Workforce Coalition in 2022. The OCEWC is comprised of nearly 60 different organizations from around the state including other electric utilities, education providers, state agencies, union labor, municipalities, community-based organizations, nonprofits, local workforce investment boards, and other related stakeholders. The OCEWC has created and adopted a strategic plan with a priority of focusing on those occupations most in need to support the transition now including jobs in energy efficiency, construction, and energy infrastructure. The Coalition has pursued two separate grants this year to support the work. If successful, some of the funds would be used to pursue a market study that would evaluate the workforce needs in the clean energy sector, including additional policy drivers at the state and federal level that will increase workforce needs in the state.

All of PGE's infrastructure related grant applications include strong labor standards to attract and retain a workforce to build the proposed projects as well as coordination with the OCEWC. PGE recognizes the importance of not only supporting an equitable and inclusive clean energy workforce, but also ensuring that the implementation of our grants is benefiting those most impacted by the effects of climate change. PGE will provide updates to interested parties on the strategy to accomplish workforce and Justice40 goals as grants are awarded and implemented.

Appendix A: Comment and Response Crosswalk

This appendix catalogues stakeholders' comments as identified by PGE and provides a reference to the chapter and section number in which PGE responded to the comment. In many cases, the comment is only represented by a few words so that it can be searched for and found in the original comment document.

Comment Source	Comment	Sec #	Section
AWEC	PGE's proposed no-regret transmission actions are the result of unrealistic model constraints rather than economic analysis.	2.1	Comprehensive transmission response
AWEC	PGE's transmission Action Items are not actionable, in part evidenced since they did not change between the filed CEP/IRP and the Addendum.	2.1	Comprehensive transmission response
AWEC	PGE's CEP/IRP market price forecast is unreliable and not consistent with planned resource additions or planned sales of GHG emitting energy, leading to unreliable portfolios and portfolio costs.	4.1	Price forecasting
AWEC	The ELCC estimates do not take the impact of similar resources into account, which may lead to incorrect values and a deficit portfolio.	4.2	ELCC values
AWEC	Due to the Preferred Portfolio not being tested in an hourly adequacy model it may not meet reliability standards.	4.3	Resource adequacy
AWEC	PGE created an arbitrary benefit for CBREs to justify their acquisition beyond the small-scale renewables requirement in ORS 469A.210 and should also examine biomass resources to satisfy this mandate.	5.4	CBRE acquisition
CRITFC	PGE should take into consideration and implement where applicable our 2022 Energy Vision for the Columbia River Basin.	9.2	Tribal engagement
CRITFC	CRITFC recommends that PGE develop a process to meaningfully engage tribes/tribal communities during the development of its CEP and beyond.	9.2	Tribal engagement
CRITFC	PGE should refer to CRITFC's Opening Brief in UM 2273 regarding implementation of House Bill 2021 (CRITFC Opening Brief UM 2273). In particular, Section I, Section II.B and Section II.D.	9.2	Tribal engagement

Comment Source	Comment	Sec #	Section
CUB	PGE should include the Additional EE that was selected in portfolio analysis within the Action Plan. CUB is open to discussing securitization over financing, and requests additional information on securitization of EE.	3.1, 3.2	Action Plan, Portfolio considerations
CUB	PGE should explain in more detail how its proposed CEP actions result in environmental and health benefits from expected GHG reduction	5.1	Informational CBIs
CUB	PGE should explain in more detail how its proposed CEP actions effect the reliability and resiliency of the electric system	5.1	Informational CBIs
CUB	CUB is interested in further information around how community engagement (from EJ communities, CBAIG) was factored into Community Benefit Indicator (CBI) development.	9.1	Outreach and engagement
CUB	CUB would like to see more ways that the Company can connect specifically with community members (e.g., after hours) to offer information on how CEP and IRP projects and programs affect individual customers lives.	9.1	Outreach and engagement
CUB	PGE should work with community organizations on coordinating meeting spaces/engagement opportunities that engage more community members, specifically underserved and EJ communities. Information should be less technical/connected to their daily lives and interests.	9.1	Outreach and engagement
CUB	CUB believes that… PGE could provide a summary of its proposed portfolio specifically related to how its IRP plan will impact customers, particularly for those communities that may be impacted by future CBRE projects and resource procurement.	9.3	Accessibility
CUB	Communities are focused on how traditional utility planning processes directly impact customers, especially low-income customers, communities of color, and other frontline communities. …incorporate a section dedicated to how IRP and CEP plans directly impact these customers' daily lives.	9.3	Accessibility
CUB	We also encourage the utility to utilize the UCBIAG in the creation of future CEPs to help with overall CEP accessibility.	9.3	Accessibility
CUB	PGE should restructure its typical outreach techniques to focus less on the technical and macro level information and to focus specifically on how its	9.4	Feedback

Comment Source	Comment	Sec #	Section
	plans and portfolio will impact the micro level of community groups and individuals.		
CUB	What feedback from Learning Lab settings was incorporated or not incorporated into the plan, and how that engagement went beyond agenda setting for future sessions.	9.4	Feedback
CUB	CUB is also interested in understanding how stakeholder engagement and feedback was considered in these spaces. …it is still unclear how the Company used the information from stakeholders to help inform the CEP or IRP or how changes were made to these plans based on feedback.	9.4	Feedback
CUB	PGE should file updates on its planning for use of these funds and include analyses of how it expects the applicable federal resources it utilizes will provide the 40 percent benefits and what those benefits will look like.	9.5	Tax Incentives and funding opportunities
Deep Blue Pacific	PGE should revise the Preferred Portfolio to reflect that offshore wind is part of the least cost and least risk Preferred Portfolio.	6.2	Model specifications
Deep Blue Pacific	PGE should conduct an RFP for long lead-time resources in order to send market signals to developers of offshore wind and other long lead-time resources.	7.4	Timing
Energy Advocates	A technical workshop on the CEP/IRP transmission options is needed.	2.1	Comprehensive transmission response
Energy Advocates	There are concerns that the transmission proxy resources are in the Preferred Portfolio too soon given the time it takes to develop transmission projects.	2.1	Comprehensive transmission response
Energy Advocates	More information is requested regarding the cost of out-of-region transmission proxies and if costs have been updated.	2.3	Proxy Transmission Cost
Energy Advocates	PGE should include of the Additional EE that was selected in portfolio analysis within the Action Plan.	3.1	Action Plan
Energy Advocates	Highlighted the disadvantages of financing and raised questions about cost-effectiveness and PGE role in determining the quantity of EE to be procured.	3.2, 3.3	Action Plan, Planning and execution
Energy Advocates	As more VERs and demand side resources enter the system PGE's operational strategies will need to evolve.	4.4	Operations

Comment Source	Comment	Sec #	Section
Energy Advocates	PGE is asked to provide details of the CEP/IRP economic dispatch and recommended to include the social cost of carbon and health benefits in this dispatch.	4.4	Operations
Energy Advocates	The projected total (retail + wholesale) GHG emissions are too high in the CEP/IRP and not consistent with overall Oregon GHG targets.	4.4.2	Economic Dispatch
Energy Advocates	The AdopDER model does not account for several Oregon incentives for low-and-moderate-income households.	4.6	Input assumptions
Energy Advocates	PGE should include an additional CBI related to Tribal priorities.	5.1	Informational CBIs
Energy Advocates	PGE should seek to understand how the CEP itself advances progress in its CBIs and should include actions in the Action Plan explicitly related to CBIs.	5.1	Informational CBIs
Energy Advocates	How did PGE determine 155 MW as the maximum amount of realistic and achievable CBRE potential in the Action Plan?	5.3	Maximum CBRE potential
Energy Advocates	PGE should run a model sensitivity with higher adoption of CBRE and distributed-generation resources.	6.1	CBREs & DERs
Energy Advocates	PGE should be required to model a portfolio that selects 125 percent of the maximum stated attainable CBRE resources.	6.1	CBREs & DERs
Energy Advocates	Can PGE clarify where the analysis of High and Low Need Futures can be found?	6.2	Model specifications
Energy Advocates	PGE should model early Colstrip exit and modify the Action Plan accordingly.	6.2	Model specifications
Energy Advocates	PGE’s CBRE actions should go beyond an RFP to include additional approaches to acquire CBREs that are unlikely to bid into an RFP due to the resources required to submit a bid.	7.1	CBREs
Energy Advocates	Add energy justice focused items/actions to the Action Plan and to future CEP/IRPs.	7.1	CBREs
Energy Advocates	The scoring criteria for RFPs should include CBIs or other non-price factors to maximize benefits for environmental justice communities.	7.3	Scoring
Energy Advocates	We also ask the Commission to direct PGE to utilize the UCBIAG to continue to facilitate, and improve on, other community engagement efforts.	9.1	Outreach and engagement

Comment Source	Comment	Sec #	Section
Energy Advocates	PGE should take a more thorough approach to Tribal Engagement: how will PGE accomplish their goal to "[b]Build awareness, inform…" or "Increase community participation, including Tribal…"; prioritize finding a Tribal representative for the CBIAG; consider the CRITFC Energy Vision.	9.2	Tribal engagement
Energy Advocates	Increase accessibility of all or part of future CEPs.	9.3	Accessibility
Energy Advocates	PGE should track the feedback it receives and how it uses it.	9.4	Feedback
GEI	Provides recommendations for how PGE can communicate facts to retail customers regarding energy and its GHG content.	8.3	RECs
Grid United	The two CEP/IRP proxy transmission resources do not capture all interregional benefits of new transmission, and an interregional proxy resource that would provide these benefits should be included in future planning work.	2.4	Options
NewSun	The Desert Southwest and Wyoming Wind transmission proxies may not be technically feasible in the CEP/IRP timeline.	2.1	Comprehensive transmission response
NewSun	The OPUC should host a workshop on transmission and discuss if the BPA options and TSRs in the CEP/IRP are still available.	2.1	Comprehensive transmission response
NewSun	More information is requested regarding the out-of-region proxy transmission development and costs, if these costs are reflective of costs found on the market, and concerns are expressed that the costs may be low.	2.3	Proxy Transmission Cost
NewSun	PGE should curtail thermal plant usage when those plants are being run for non-PGE load.	4.4.2	Economic Dispatch
NewSun	PGE has not adequately addressed CBRE technical achievable potential in its modeling and should model up to 125 percent of the currently assumed potential.	6.1	CBREs & DERs
NewSun	PGE should run a model for distributed energy resources up to their achievable potential.	6.1	CBREs & DERs
NewSun	PGE should provide draft avoided cost information in the same format as will be provided in final form following IRP acknowledgement.	8.2	Avoided cost information

Comment Source	Comment	Sec #	Section
OPUC	PGE is invited to provide additional details regarding its long-term decarbonization strategy.	1.1	Clean energy plan
OPUC	Does the CEP/IRP decarbonization strategy require future market interactions and participation?	1.1	Clean energy plan
OPUC	At what junctures might PGE consider material changes to the CEP/IRP decarbonization strategy?	1.1	Clean energy plan
OPUC	What information and data will be used to determine if a change in course for the decarbonization strategy is needed?	1.1	Clean energy plan
OPUC	What are the circumstances that could result in poor outcomes for customers due to PGE's planned decarbonization strategy actions?	1.1	Clean energy plan
OPUC	Are there any decarbonization strategy actions excluded from the CEP/IRP due to poor outcomes for customers?	1.1	Clean energy plan
OPUC	PGE should provide additional detail/information about its near-term Tx action items like SoA congestion relief and Bethel-Round Butte upgrades.	2.1	Comprehensive transmission response
OPUC	PGE should explain and provide more information on its long-term transmission strategy for complying with HB 2021.	2.1	Comprehensive transmission response
OPUC	Recommendation 18 - Including the 50MWa of additional EE in the Preferred Portfolio and describing the strategy to procure the additional EE within the Action Plan window.	3.1	Action Plan
OPUC	Recommendation 19 - PGE should provide an update on its collaborative efforts with ETO towards procuring additional EE resources by 2030.	3.1	Action Plan
OPUC	OPUC note concerns about the avoided cost information provided for energy efficiency.	3.4	Avoided costs within UM 1893
OPUC	Why is the ELCC value of the Gorge Wind proxy resource higher than in the 2019 IRP Update?	4.2	ELCC values
OPUC	Why are there differences between tuned and untuned ELCC values in the CEP/IRP?	4.2	ELCC values
OPUC	PGE should test the adequacy of the Preferred Portfolio and report the LOLH and LOLE metrics associated with it, and explain why it chose to plan for that level of adequacy.	4.3	Resource adequacy

Comment Source	Comment	Sec #	Section
OPUC	PGE should account for the benefits of the WRAP in future CEP/IRPs.	4.3	Resource adequacy
OPUC	Due to concerns that the annual GHG emissions accounting approach is insufficiently detailed (and may lead to a system that does not comply with emission targets) an hourly emissions analysis is requested.	4.7	Temporal granularity
OPUC	Recommend the inclusion of additional iCBIs specific to Tribal priorities	5.1	Informational CBIs
OPUC	PGE should provide a supplemental analysis that satisfies the HB 2021 requirement to examine the costs and opportunities of offsetting energy generated from fossil fuels with community-based renewable energy.	5.5	CBRE trade-offs
OPUC	PGE should provide insight into the level at which CBRE additions are no longer low regrets actions and tradeoffs of including different levels of CBREs in portfolio analysis.	5.5	CBRE trade-offs
OPUC	PGE should provide an interim pCBI that captures the different benefits across all resource types across all portfolios.	5.6	Portfolio CBIs
OPUC	PGE should update its portfolio scoring analysis to express pCBIs in dollar terms.	5.6	Portfolio CBIs
OPUC	PGE should provide additional analysis that decreases the annual capacity limit imposed in portfolio modeling to explore the cost and risk implications of spreading out capacity additions to meet 2040 needs.	6.2	Model specifications
OPUC	How have the capacity additions in the Preferred Portfolio informed PGE's long-term decarbonization strategy as it relates to acquiring non-emitting capacity over time?	6.2	Model specifications
OPUC	It is unclear whether the inclusion of Colstrip in the portfolio beyond 2025 appropriately balances cost, risk, the pace of GHG reductions, and community impacts because no early-exit portfolio was analyzed.	6.2	Model specifications
OPUC	PGE should re-design and re-evaluate the Preferred Portfolio without assuming up to 800 MW of transmission expansion access.	6.3	Preferred Portfolio
OPUC	PGE should adopt a scoring metric for the pace of GHG reductions to show the tradeoffs between cost, risk, the pace of GHG reductions, and community impacts and benefits across portfolios.	6.4	Scoring metrics

Comment Source	Comment	Sec #	Section
OPUC	PGE should design a scoring metric for near-term cost impacts that can be applied across all portfolios and justify its use in planning and procurement decisions.	6.4	Scoring metrics
OPUC	In the future, PGE should justify portfolio analysis findings and design principles used to develop the Preferred Portfolio based on all scoring metrics, not just those that address cost and risk.	6.4	Scoring metrics
OPUC	First, does PGE plan to pursue CBRE technologies beyond the proxy resource types included in the CBRE potential study? Second, what is PGE's strategy to balance CBRE acquisition costs while maximizing community benefits; specifically considering strategy to leverage funding resources and other partnerships, and key emerging risks and decision points. Third, what steps can PGE take to overcome implementation risks and ensure that company resources associated with CBRE procurement activities are used effectively.	7.1	CBREs
OPUC	PGE should provide additional detail on proposed RFP framework, including the specific methodology to update the needs assessment, potential offramps, and how PGE will make a determination to close one round of procurement and begin another.	7.2	Procurement levels
OPUC	PGE should describe how the Company will respond if an RFP does not result in its targeted procurement level.	7.2	Procurement levels
OPUC	PGE should provide regular updates to LC 80 participants on its target procurement volume for the 2023 RFP as new information and analysis warrant.	7.2	Procurement levels
OPUC	Does the RFP pacing and supply chain analysis provide quantitative insights into resource acquisition pacing options and does PGE plan to constrain annual RFPs to match the annual RFP scenario energy and capacity additions?	7.4	Timing
OPUC	PGE should provide additional detail on its approach to small-scale renewables, including compliance position, detail for specific resource types and discussion of acquisition strategy.	8.1	Small scale renewables requirement

Comment Source	Comment	Sec #	Section
OPUC	How might PGE realize value from an expected increase in the size of the REC bank through time as the number of RECs produced annually exceed the amount needed for RPS compliance?	8.3	RECs
OPUC	Recommendation 4: In Reply Comments, PGE should explain what steps it is taking for this IRP/CEP, and can take in the future, to communicate its HB 2021 compliance strategy in a manner that is accessible and meaningful to the customers and communities it serves.	9.3	Accessibility
OPUC	Recommendation 3: In Reply Comments, PGE should provide a table that identifies key feedback received by community and other stakeholders, the affiliation of the person providing the feedback, whether and where PGE incorporated the feedback, and why.	9.4	Feedback
OSSIA	PGE should provide draft avoided cost information in the same format as will be provided in final form following IRP acknowledgement.	8.2	Avoided cost information
REC	PGE should change the CEP/IRP assumptions regarding QF renewals and should change the success rate applied to contracted but not online Schedule 202 resources.	4.6	Input assumptions
REC	PGE should only include energized community solar projects in the CEP/IRP.	4.6	Input assumptions
RNW	The CEP/IRP transmission modeling is overly generic and does not demonstrate which projects are best, the timeline is quick, offshore wind should be considered for congestion relief, and merchant transmission should be considered.	2.1	Comprehensive transmission response
RNW	PGE should rethink how conditional firm 200hr transmission is modeled and not include any hours of curtailment.	2.2	Conditional firm transmission modeling
RNW	For the next planning cycle the ELCC methodology should take the portfolio effect into account, among other suggested changes.	4.2	ELCC values
RNW	For the next planning cycle, the resource adequacy capacity assessment method should examine more planning metrics, calculate capacity need differently, and other suggestions.	4.3	Resource adequacy
RNW	For the next planning cycle, the resource adequacy model should use more granular market power import assumptions.	4.3	Resource adequacy

Comment Source	Comment	Sec #	Section
RNW	PGE should provide a discussion and comparison of the WRAP and CEP/IRP adequacy, integrate WRAP data into CEP/IRP processes, and work to align the processes.	4.3	Resource adequacy
RNW	Sub-annual emissions accounting is requested, in part due to the risk of overgeneration, curtailment, emissions netting, and VER integration not being properly addressed with annual analysis.	4.5	Emissions accounting
RNW	Power plant Beaver's change in generation between the filed CEP/IRP and the Addendum is evidence of resource "shuffling."	4.5	Emissions accounting
RNW	PGE is "shuffling" GHG emitting resources to swap higher GHG intensity resources for lower intensity ones.	4.5	Emissions accounting
RNW	In the CEP/IRP PGE advocated for changing the market unspecified CO2e emissions rate.	4.5	Emissions accounting
RNW	PGE's CEP/IRP decarbonization modeling is compared to modeling done by other organizations.	4.5	Emissions accounting
RNW	Hydrogen input assumptions are requested, and recommendations on how to model hydrogen are provided.	4.6	Input assumptions
RNW	PGE should adopt an hourly or systems-level analysis of its emissions target.	4.7	Temporal granularity
RNW	PGE may be underestimating GHG emissions due to the need for thermal resources to provide ancillary services, and those services not being captured under the current modeling timestep.	4.7	Temporal granularity
RNW	PGE's plan should have thorough and direct incorporation of energy justice principles and conversations.	5.1	Informational CBIs
RNW	PGE should be able to clearly attribute changes in CBIs to specific CBRE actions and include tribal and environmental iCBIs.	5.1	Informational CBIs
RNW	There is a need for more capacity building and resources in under-resourced communities for them to gain experience and an ability to engage in planning and building CBRE projects.	5.2	CBRE community engagement
RNW	PGE should incorporate a clean capacity glidepath within portfolio modeling to smooth the transition away from GHG-emitting resources and prevent the risk of "hockey stick" transitions in resource additions at critical milestones.	6.2	Model specifications

Comment Source	Comment	Sec #	Section
RNW	The IRP does not test the economic value of offshore wind because the offshore wind portfolio in the IRP cannot be compared to portfolios containing transmission expansion.	6.2	Model specifications
RNW	Offshore wind is part of the least-cost and least-risk portfolio and should be included in the Preferred Portfolio.	6.2	Model specifications
RNW	A portfolio that includes offshore wind and other non-generic resources makes a more interesting and relevant comparison than PGE's Preferred Portfolio.	6.2	Model specifications
RNW	Modeling specific rather than generic resources would provide clarity on post-2030 resources and send better market signals to developers.	6.2	Model specifications
RNW	The Preferred Portfolio should contain specific resources rather than generic resources.	6.2	Model specifications
RNW	PGE appears to not be fully accounting for all the factors considered by NREL in the calculation of offshore wind costs, producing conservatively high costs after 2030.	6.5	Supply-side options
RNW	Offshore wind should not be characterized as an emerging technology.	6.5	Supply-side options
RNW	PGE should conduct an RFP for long lead-time resources in late 2025 for acquisition of resources in the early 2030s.	7.4	Timing
RNW	Still like to see a specific plan to ensure that historically excluded and underserved communities will be included in future engagement.	9.1	Outreach and engagement
RNW	Continue to provide information on the progress of Tribal engagement as well as any other efforts beyond the Strategic Tribal Engagement Plan that PGE may pursue in working with Tribes.	9.2	Tribal engagement
Swan Lake	The assumption of a 38-year useful life used in PGE’s derivation of pumped hydro cost estimates is too short and Staff should direct PGE to re-run portfolio analysis using a 50-year life and evaluate a 75-year sensitivity.	6.5	Supply-side options

Appendix B: Strategic Tribal Engagement Plan

Last year (2022), we created our inaugural Strategic Tribal Engagement Plan (STEP) to assist with Tribal relations and establish an internal and external process for engagement. The STEP provides a framework for our teams to develop and maintain successful Tribal relationships by setting goals, identifying actions and implementing best practices to meet desired outcomes.

Strategic Tribal Engagement Plan

Acknowledgment

“Everywhere you are, Indians have been…
Every hill, every creek, every meadow, every forest,
every inch of Oregon has a story of its connection
to the indigenous peoples who lived here.”

*— Testimony of Jeremy Fivecrows (Nez Perce)
to Portland City Council, 2005*

We take this opportunity to honor the Indigenous Peoples who continue to care for the lands that we work in since time immemorial, and who continue to remind us that living in a place creates responsibilities to the water, air, animals, land and its people.

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Introduction

PGE is committed to proactive, strategic, and effective Tribal engagement and partnership in recognition of Tribal sovereignty. As a company, we have deep respect for Tribal wisdom, worldviews and work. Developing a programmatic approach to Tribal relations will ensure that meaningful Tribal engagement is standard practice across PGE. PGE's Strategic Tribal Engagement Plan (STEP) provides a framework for PGE's approach to working with Tribes.

Purpose of STEP

PGE's STEP provides a framework for PGE teams to develop and maintain successful Tribal partnerships by setting goals, identifying actions and implementing best practices to ensure desired outcomes through Tribal relations.

This document is intended for PGE employees who work with Tribes, to provide consistency in how we approach Tribal relations. PGE is invested in and thoughtful about our Tribal engagement strategy, which informs our work at the highest level. This document does not replace any existing guidance specific to individual work spheres.

PGE currently has the opportunity to work closely with federally recognized Tribes in Oregon, Washington and Idaho, including:

- Confederated Tribes of Grand Ronde
- Confederated Tribes of Siletz Indians
- Confederated Tribes of the Umatilla Indian Reservation
- Confederated Tribes of Warm Springs
- Confederated Tribes and Bands of the Yakama Nation
- Cowlitz Indian Tribe
- Nez Perce Tribe

In the future, we may have the opportunity to engage with other Tribes not listed above. Tribes are PGE's customers, business partners, stakeholders and regulators. As such, PGE's mission is to be thoughtful and strategic when working with Tribes. We are a leader among businesses nationally in Tribal consultation and partnerships.

Alignment with PGE strategy

We acknowledge that our journey toward a clean energy future must include Tribes as partners. Tribes are sovereign governments, economic drivers, political influencers and nation builders. PGE's service territory and generation sites are part of Tribal Ceded[1] and Usual and Accustomed[2] lands. The Confederated Tribes of Warm Springs has been PGE's business partner on the Pelton Round Butte hydroelectric project for over six decades. The Confederated Tribes of Grand Ronde are one of our key customers. Tribal governments support the regulatory process when they review PGE's environmental and licensing permits. All regional Tribal governments act in a stakeholder capacity and review our Federal Energy Regulatory Commission (FERC), Energy Facility Siting Council (EFSC) and other licenses and permits. We work closely with Tribes to negotiate franchise agreements for transmission lines. Our service territory and generating areas are also home to multiple individuals and communities who identify as Native American and Alaska Natives. Last but not the least, individuals who identify as Native American are part of our employee workforce.

As such, Tribal relations are a critical part of our company's overall strategy and operations. We have multiple touch points with Tribes across the company, be they in Operations, Public Affairs, Transmission Services, Strategy and Integration, Distributed Systems Planning, Key Customer, Power Operations, Environmental and Licensing, including fish passage, recreation facilities or managing our cultural resource impacts. Moreover, it aligns with PGE's Diversity, Equity and Inclusion best practices.

STEP is one tool that strengthens PGE's overall purpose

We exist to power the advancement of society. We energize lives, strengthen communities, and drive advancement in energy that provides social, economic and environmental progress.

Our company vision is to lead the clean energy future. Together with our customers, stakeholders, and communities, we will lead the energy transformation by decarbonizing, electrifying, and performing. As an important and multifaceted demographic, Tribes and Tribal interests are intrinsically connected to our imperatives. PGE's success with Tribal relationships will help our path towards our three long-term imperatives — decarbonize, electrify and perform.

1. *Ceded lands: Areas where a Tribe did "cede, relinquish, and convey to the U.S. all their right, title, and interest in the lands and country occupied by them" at treaty signing or when reservations were established.*
2. *Usual and Accustomed lands: Lands within and adjacent to areas to which a tribe(s) usually traveled or was accustomed to travel to hunt, fish, gather roots and berries or for any other cultural or spiritual purposes.*

STEP goals

PGE's Strategic Tribal Engagement Plan describes three goals to ensure desirable outcomes:

1 **Tribal sovereignty**

2 **Tribal partnerships**

3 **Program weave**

Tribal sovereignty

Ensure the company learns, understands and respects Tribal legal interests and perspectives as they pertain to PGE's strategy and operations. And how those operations may directly or indirectly impact Tribal governments and their members.

OBJECTIVE	ACTION	OUTCOME
Support the company's understanding of Tribal perspectives and its application to our responsibilities of consultation.	Provide STEP training to heighten cultural competence and humility on Tribal rights, federal and state law, Tribal history, cultures, traditions and best practices to company leaders, key managers and appropriate staff whose work interfaces with Tribes.	Policy and resource management decisions that appropriately integrate Tribal rights and interests.
PGE staff to engage with Tribes in substantive and meaningful consultation in support of PGE objectives.	1. Develop best practices for Tribal consultation. 2. Educate staff to identify and advance Tribal partnership opportunities. 3. Evaluate emerging policy issues with Legislative Affairs staff and provide recommendations. Confer annually with Tribal leaders and staff to identify emerging policy and project work to proactively address Tribal consultation requirements.	Meet and exceed compliance with required regulations around Tribal outreach and consultation.

Tribal partnerships

Leverage partnerships to maximize mutual success.

OBJECTIVE	ACTION	OUTCOME
Identify partnership opportunities with Tribal governments, inter-Tribal organizations, Tribal Affairs teams in other organizations, Tribal community organizations and Tribal employees to further PGE's strategic goals of decarbonization, electrification and performance.	Identify, organize, and participate in relevant events and programs that offer networking and relationship-building opportunities between PGE and Tribal personnel.	1. Increase mutual trust between Tribes and PGE, which provides a foundation for long-term successful partnership. 2. PGE's management decisions and actions appropriately consider Tribal issues. 3. Enhanced capacity building in Tribal communities.

Program weave

Promote integration and use of STEP throughout the company.

OBJECTIVE	ACTION	OUTCOME
STEP is effectively integrated into PGE's programs that interface with Tribes.	1. Provide STEP Training to identified staff. 2. Advise leadership on relationship building, communications and messaging in speeches, briefings and updates, where appropriate. 3. Co-organize on-the-ground events and opportunities with PGE leadership and Tribes. 4. Identify opportunities to highlight STEP at trainings, conferences and professional society meetings.	1. Increased awareness of Tribal concerns and needs, and PGE's success in addressing those appropriately. 2. Tribes regard PGE as an engaging partner across horizontal and vertical lines, with appropriate alignment and relationships between individuals at the right level.

STEP roles

At PGE, every employee has an opportunity to be a champion of Tribal relations. We encourage learning about area Tribes, developing a deep regard and respect for Tribal worldviews and being a diligent company representative.

There are several roles that are responsible for PGE's Tribal relations. These are generally described below.

Tribal Liaison

PGE's Tribal Liaison is part of the company's Government Affairs team. This position is responsible for the overall programmatic implementation of PGE's STEP. It reports to the Director of Government Affairs. Primary responsibilities of the Tribal Liaison include:

EXTERNAL

- Conduct regular and sustained outreach to Tribal government, leadership and staff in support of PGE's initiatives.
- Identify common interests with Tribes when consistent with PGE's overall objectives.
- Coordinate PGE involvement and Government Affairs efforts as needed in federal, state, local agency and community forums on legislative efforts and other matters related to Tribal issues or interests.
- Establish and maintain favorable strategic relationships with state and federal agency personnel, other utilities, customer representatives and interest groups on issues of mutual Tribal interests.
- Serve as a company spokesperson at appropriate forums; represent PGE at Tribal events.
- Organize and host meetings with Tribal Leaders and PGE leadership and staff.

INTERNAL

- Provide expertise and timely support to other PGE groups on Tribal matters, including supporting business initiatives with Tribes.
- Monitor and report on topical or pertinent regional and national Tribal energy issues.
- Maintain awareness of regional inter-tribal relations.
- Advise front line staff and key managers who interact with Tribes on conflicting/competing interests or possible impacts of proposed PGE actions on Tribes.
- Develop training materials for use by PGE management and staff on Tribal relations.
- Regularly report to management on status of major initiatives, agency rulemakings or similar proceedings, and activities related to Tribes.
- Assist in NEPA or NHPA Section 106 consultation where Tribes' interests intersect with regional issues where likely to be political or sensitive.
- Review major communication going to Tribes.
- Be aware of Tribal issues imminent in other parts of the company and support staff, as needed.
- Serve as a facilitator with Tribes that we do not have relationships with currently.
- Serve as a cultural consultant and advise on culturally appropriate responses for a variety of events such as seasonality of communications, the death of a Tribal leader, elder or community member.
- Advocate to preserve confidential Tribal files, photos and records with PGE's Records and Information Management (RIM) team to create a virtual and physical storage system for Tribal records with controlled access. Note that privileged documents are handled separately by PGE Legal which has its own document storage system.

When should PGE's Tribal Liaison be involved?

- Any direct communication with Tribal leaders, elected Tribal positions or Tribal elders.
- Projects that have connections between Tribal interests and a larger PGE issue or strategy.
- Issues with ongoing litigation involving Tribes where appropriate.
- NEPA and NHPA consultation involving a Tribe with issues where likely to be political or sensitive.
- Sensitive Tribal issues involving but not limited to burials, human remains, Traditional Cultural Properties (TCPs) and Historical Properties of Cultural and Religious Significance to Indian Tribes (HPCRIT).
- When a new Tribal point of contact needs to be identified.
- New transmission interconnect requests from potential developers on Tribal lands.
- Legislative issues involving Tribes.
- Tribal issues with potential regional trigger.
- Tribes have interest in PGE property.
- Property disputes involving Tribes.
- Identifying the right Tribes on specific projects.
- Tribal elders or Tribal leadership are invited to PGE's facilities.

Director, Public Affairs

- Provides regular oversight to STEP and Tribal Liaison.
- Has overall oversight of STEP program.
- Leads key PGE communications to federal and state delegations, Governor's office or other elected officials on Tribal issues.
- Advises, supports and advocates for effective Tribal consultation at appropriate levels.
- Present at social and cultural gatherings with area Tribes.
- Cover for Tribal Liaison when they are not available.

Vice-President, Public Affairs

- Executive sponsor of STEP.
- Involved in high-risk and high-visibility issues pertaining to Tribes.
- Key advocate on Tribal relations to PGE leadership, including CEO.
- Primary communicator to Tribal Council members and other Tribal leadership when executive engagement is needed.
- Represents PGE at high-profile meetings, visits, and cultural and traditional events when Tribal dignitaries are present.
- Present at annual social and cultural gatherings with area Tribes.

CEO

- Represents PGE in strategic communication to Tribal chairs and elders, as appropriate.
- Present at high-profile meetings, visits, and cultural and traditional events when Tribal dignitaries are present.
- Present at annual social and cultural gatherings with area Tribes.

Legal team

- Will be involved whenever a Tribe is represented by legal counsel and whenever a communication is to or between PGE and Tribal lawyers.
- Leads discussions and authors communication related to dispute negotiations, resolutions, mediation and litigation involving Tribes.
- Reviews legal documents to and from Tribes.
- Oversees communication from other departments to Tribes when issues have potential legal impacts.
- May be involved in other actions and activities as part of advising clients.

Technical staff

PGE technical staff correspond and interact with Tribal technical staff on routine issues or tasks. These include routine FERC and EFSC filings, routine project correspondence to lead federal agencies, established coordination on plant operations, key customer manager communication on routine issues, standard consultation, preservation of confidential Tribal files, photos and records, coordinating access for Tribal staff to PGE facilities or routine franchise agreements.

Technical staff include the following departments:

- Operations
- Company hydrolicensing (biological, cultural, recreation)
- Cultural Resources
- Corporate Communications
- Structure and Origination
- Property
- Record and Information Management (RIM)
- Office of Diversity, Equity and Inclusion
- Key Customer Manager

The above are broad guidelines for Tribal engagement and there might be circumstances where various PGE groups play different roles based on the issue.

Tribal consultation best practices

> "I would consider any consultation successful in which there has been a collaborative effort and all parties acknowledge and respect the observations, comments and concerns of the other."
>
> *— Dr. Richard L. Allen, Policy Analyst, Cherokee Nation*
> *A Traditional Cultural Property of New Echota*

While PGE does not have government-to-government consultation mandates, we may seek delegated authority from federal agencies to conduct Tribal consultation, in support of environmental and cultural resources protection laws, including National Environmental Policy Act (NEPA) and National Historic Preservation Act (NHPA). PGE also undertakes numerous informal consultations for projects in areas of significance to Tribes for historical, cultural, religious or spiritual reasons. Tribes have traditional ecological knowledge (TEK) owing to their deep connections to place as stewards since time immemorial. With proactive consultation, PGE stands to better understand Tribal geographic landscapes and their elements, which help us make well-informed decisions during planning, design and execution of our projects.

For consultation to be successful, it should be ongoing, timely and ensure positional equity.

DO THE HOMEWORK

The basis for effective Tribal engagement is a foundational knowledge of the Tribes that we are working with. Learning about Tribal culture will help us appreciate Tribal worldviews and understand Tribal behaviors. This includes the Tribes' governance structure, food preferences, spiritual practices, natural resource values, family structure, education system, territorial interests (which may and often do overlap), legal rights and authorities and Tribal economic engines.

- When you know one Tribe, you know only that one Tribe. Every Tribe has its unique culture, governance and social structure as it is a product of its unique geography, history, legal status, treaties, rights, interests and other factors. For example, Tribes such as the Yakama Nation and the Nez Perce were largely single groups that stayed intact. Other disparate groups were lumped into large Confederations and therefore experienced different historic trajectories. Tribes can also differ depending on whether their treaties were made during peace or during war, what their relationship with the federal government has been, whether their membership are beneficiaries of a per capita model or a service model and what kind of alliances they have nurtured with neighboring Tribes. Tribes' legal history, including termination and restoration, can be another compounding factor. Some Tribes have sizable economic establishments and investments, while others, such as the Burns Paiute Tribe of Oregon — the smallest Tribe in the country with 410 members — have a single source of Tribal income. Therefore, it is very important to avoid generalizations.

- Understand each Tribe's governance model and decision-making process. These vary widely between Tribes and are key determinants of successful consultation. Gaining an appreciation of meeting protocols related to prayer, seasonality, food sharing and gift giving are a few practices that may affect consultation outcomes. Tribes often have two tiers of government including a legal/political tier and traditional approach. The tribal representative is not always the decision-maker.

- Tribes themselves are the best source of information about their past, present and future. Staff are encouraged to go to the official Tribal website to hear their own story. Some Tribes have museums and public relations staff that are willing to provide information. It is critical to provide sufficient time to solicit all views from a Tribe and to allow adequate time for a Tribe to gather views from its members, staff and leadership.

- Understand the Tribe's perceptions of time and allow enough time to form ongoing relationships. Perceptions of time vary across cultures. Non-native sense of time is often more linear compared to Tribal seasonal rhythms, ceremony and grieving periods. PGE staff should be aware of differences and work to accommodate Tribal schedules. Likewise, PGE staff should be clear with Tribal contacts about any exigent circumstances driving our schedule. Further, consider that true collaborative decision-making may take a long time.

- Acknowledge that Tribes have a long history of broken commitments made by federal and state partners. Trust is a critical element of any Tribal relationship.

INCORPORATE TRIBAL OUTREACH INTO PROJECT PLANNING

Beginning Tribal consultation as early as feasible is paramount.

- Distinguish Tribes from stakeholders, environmental groups and nonprofit organizations.

- Identify the Tribes who need to be part of a project. Use both official sources, such as Commission on Indian Services (CIS), and informal sources, such as Tribally-identified Usual and Accustomed land boundaries and natural features that Tribes consider for property demarcation.

- Consult official consultation guides that some Tribes maintain.

- Budget resources and time for building relationships before decisions are required. Establish the formal and informal preliminary contacts and the appropriate authorities needed for proceeding. Assess and define roles, organizational attributes and explicit procedures. It is in PGE's interest to work toward building Tribal capacity. It is recommended that we consider if there are opportunities for PGE to help build institutional capacity through our projects. Consider and plan for compensation/participation funding for Tribal input and engagement in PGE projects. Construct flexible protocols while planning projects. These protocols will allow tribes to execute on their own contributions with due consideration of project resources and procedural fairness.

- In case of anticipated conflict, PGE should make efforts to establish procedural neutrality, including using independent facilitators.

- PGE's project managers should have a plan to protect sensitive and confidential Tribal information.

- Do not depend overly on lead federal agencies for consultation outcomes. PGE must play an active role with Tribes throughout a project.

- For NEPA projects, sometimes Tribal consultation may be appropriate even if a proposed action is covered by a Categorical Exclusion that relieves the lead federal agency of the need to prepare an Environmental Impact Study (EIS) or an Environmental Assessment (EA). PGE should take care to consider that the proposed action covered by the categorical exclusion does not involve "extraordinary circumstances" relating to potential impacts to Tribal land uses, access, or cultural or religious values, as articulated in the Council on

Environmental Quality and Department of the Interior's NEPA regulations. If for any reason a NEPA document will not be prepared, an appropriate non-NEPA document should be used for consideration of Tribal concerns. Such non-NEPA documentation may consist of Tribal consultation logs or data recovery reports.

- PGE's licensing and cultural resources staff must contact their Tribal counterparts prior to sending out permits for their official review and approval.
- When feasible, offer to travel to Tribal Offices recognizing that resource issues may be affecting a Tribe's participation. It is appropriate to consider paying for costs associated with consultation.

CONSULTATION AND COLLABORATION

At PGE, we regard consultation as an ongoing process conducted in a timely, intentional, and respectful two-way manner. Successful consultation begins early in the planning stages and is predicated on both PGE and the Tribes being knowledgeable about the project and priorities.

- Respect tribal sovereignty and self-determination and be aware that Tribes have discretion and control over their means of reaching desired outcomes according to their own cultural values and norms.
- Be aware that Tribal authority can be nested in many layers, both formal and informal, and can change over time. Formal authority may rest with Tribal Council, committees or commissions, regulatory offices or Tribal Historic Preservation Officer (THPO), but at times elders alone may be the authority to speak on oral traditions and cultural matters. Also, it will be necessary to clarify if individual leaders can speak on behalf of the Tribe.
- When meeting with Tribes, positional compatibility and horizontal alignment between roles must be followed.

Tribal governments, tribally recognized experts, and a Tribe's view of itself as well as of its past, present and future, all legitimately represent a Tribe's interests. Accordingly, each Tribe has the discretion to collect and manage its data according to its own standards and practices.

Next steps

PGE has identified several promising implementable initiatives as part of STEP. These are organized around projects, processes, programs and policies.

PROJECT	LEAD TEAM	CROSSFUNCTIONAL TEAMS
Tribal Ecological Knowledge projects (TEK)	Wildfire Mitigation and Resiliency	Government Affairs Cultural Resources
Community volunteer projects with Tribes (GED completion, STEM)	Corporate Social Responsibility	Government Affairs
Tribal art installations at PGE locations	Facilities Management	Property Government Affairs
Support relevant exhibits at Tribal Museums	Cultural Resources	Government Affairs

PROCESS	LEAD TEAM	CROSSFUNCTIONAL TEAMS
Apply equity lens to supplier diversity and PGE Foundation grant process	Supply Chain	DEI Government Affairs
Land Acknowledgement Statement	Government Affairs	DEI Brand Marketing Communications
Observe Oregon's Indigenous Peoples Day	Government Affairs	Brand Marketing Communications
Consider blessing ceremony/ethnographic place names at new PGE locations (generations, substations, parks)	Facilities Management	Property Legal Government Affairs
Replanting with traditional plant species	Vegetation Management	Environmental Landscaping
Consider cultural easement	Properties	Legal Government Affairs
Invite Tribes to Environmental Roundtable	Environmental	Government Affairs

PROGRAM	LEAD TEAM	CROSSFUNCTIONAL TEAMS
STEM Training	Government Affairs	HR — Learning and Development
Incorporate Tribal history into Parks Junior Ranger Program	Environmental-Parks	Brand Marketing Communication
Recruit Tribal members for cultural resource monitor positions	Cultural Resources	HR
STEM partnership with Tribal schools	Corporate Social Responsibility	Government Affairs
Line Apprentice program for Tribal youth	HR Workforce Planning	HRBPs Line Apprenticeship Program DEI Government Affairs
Internship Program. Partner with the American Indian Science and Engineering Society (AISES), NRCS and DOE. Recruit from native conferences and posting with appropriate job boards/schools like Tribal Colleges to further recruit Native employees	Corporate Social Responsibility, Project Zero	HR
Continue agreements to provide hands-on training to help Tribes run their own hydroelectric operations, hands-on training on PGE's trading floor and power operations.	HR	Government Affairs
Tribal fire crews work in our vegetation management program in fire off-season	Vegetation Management	HR Legal
Establish Native American BRG at Pelton Round Butte	DEI	Brand Marketing Communications

POLICY	LEAD TEAM	CROSSFUNCTIONAL TEAMS
Tribal community energy plans collaboration	Government Affairs	Project Symphony team
Partnerships with key Tribal organizations such as Affiliated Tribes of Northwest Indians (ATNI)'s Climate Change and Energy division	Community Impact	Government Affairs
Capacity building through START program (Strategic Technical Assistance Response Team)	Government Affairs	
Tribal mentorship through Oregon's Association of Minority Entrepreneurs	DEI	Supply Chain Government Affairs
Increase visibility of Native led and Native serving non-profit organizations during PGE's Employee Giving Campaign.		
Develop guidance for PGE employees on found migratory bird feathers and/or carcasses at our facilities to positively contribute to increasing the availability of culturally important feather materials through the eagle repository in Denver and the SIA repository for non-eagle feather materials.	Environmental-Biologists	Government Affairs

Conclusion

PGE has worked closely with Tribal governments, businesses, elders, employees, and organizations for many years. STEP provides the framework and tools to strengthen our existing relationships and forge new ones in a dynamic world. We will continue to listen to and learn from Tribes, while relaying in a timely manner information on our needs and priorities. STEP will help us have a programmatic approach to PGE's Tribal relations. Being intentional about our work with Tribes and in alignment with our overall company strategy is critical to the future of our business. Working with Tribes intentionally, in alignment with our overall company strategy, is critical to the future of our business.

PGE

An Oregon kind of energy.℠

Cover photo: Deschutes River near Pelton Dam, Madras, Oregon

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