Portland General Electric
121 SW Salmon Street • Portland, OR 97204
portlandgeneral.com

May 31, 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 Response to Initial Comments

Dear Filing Center:

Enclosed for filing today in the above-referenced docket is Portland General Electric Company's (PGE) response to initial Staff and stakeholder comments (Round 0 Comments) on PGE's 2023 Clean Energy Plan (CEP) and Integrated Resource Plan (IRP). Per Commission Order No. 23-010, the 60-day initial comment period was added to this inaugural CEP review schedule in lieu of a public input process on PGE's draft IRP in advance of filing.

PGE appreciates the thoughtful input provided by stakeholders in this phase and has sought to respond to each point of feedback. Appendix A to PGE's response lists each comment and references the chapter in which it is addressed.

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

Sincerely,

/s/ Riley Peck

Riley Peck
Senior Manager, Regulatory Strategy
Resource & Regulatory Strategy

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Introduction

PGE's submission of its combined 2023 Clean Energy Plan and Integrated Resource Plan (CEP/IRP) marks a major milestone in the implementation of the state's landmark clean energy legislation, House Bill 2021 (HB 2021). As Oregon's largest electricity supplier, we recognize our unique role in addressing climate change and leading an equitable clean energy transition in Oregon.

Detailing a path to achieving the emissions targets set forth in HB 2021 and meeting expectations outlined in Commission orders was a significant undertaking that inherently changed PGE's approach to long-term resource planning. Our goal was to produce a CEP/IRP that demonstrates alignment between PGE's priorities and values and the public policy goals of the state. We set out to mitigate risks for customers while balancing affordability and emissions reduction during a highly dynamic period of change for our industry. We produced a CEP/IRP that was flexible and could be adapted as we continue to learn and as conditions change and new technologies and market opportunities arise. Importantly, we designed our plan to invite further conversations with our customers, communities, stakeholders and the Commission.

We would like to acknowledge the time, work, and valuable contributions of so many participants to this process. The quality and commitment of participation is evident in this first round of initial comments we received. We recognize that this initial round of comments is surfacing issues that will be considered in detail over the next six months, and we look forward to additional feedback as Staff and stakeholders review our modeling, analysis, and proposed actions. Accordingly, we have focused our efforts on responding to concerns and suggestions rather than conducting modeling changes or revisions to the filed CEP/IRP. Our initial responses to this first round of comments are included below. We anticipate providing more details and clarity into key areas of the CEP/IRP during the ensuing public comment periods.

Understanding how the document was developed

- PGE reviewed all comments submitted.
- We extracted questions, comments, and points of clarification from the submitted comments – just over 100 items, from nine parties. If you find that we missed something, please bring it to our attention.
- We organized the comments into 13 topical categories.
- We crafted a summary of the comments, intending to represent the salient point(s).
- We wrote a response that addresses the salient point(s).
- At the end of the document, we included a list of the items we addressed and where the responses can be found in the document.

Chapter 1. Engagement

1.1 Centering Energy Justice

The Energy Advocates open their initial comments with a reminder that "HB 2021 is an environmental-justice-led policy" and recommend revisions to the CEP "in consideration of energy justice principles like recognition, distributional, restorative, and procedural justice."[1] The Energy Advocates advise PGE to use the CEP/IRP to describe and communicate more directly how planned actions will impact environmental justice communities and the "everyday existence of people."[2]

PGE's response

PGE appreciates the centrality of environmental justice issues to HB 2021. Our inaugural CEP/IRP is a first attempt at more directly applying these principles to resource planning processes. Going forward, we will continue to leverage engagement processes like the Community Learning Labs and the Community Benefits and Impacts Advisory Group (CBIAG) to better understand environmental justice opportunities and priorities and to apply them consistently across utility planning areas. While the CEP/IRP encompasses a wide planning scope, it is part of a planning ecosystem that also includes the distribution system plan (DSP), transportation electrification plan (TEP), flexible load multi-year plan (MYP) and others. Ultimately, many of the details of specific community benefits and distributional justice elements will be addressed through program-specific metrics and design. We see significant opportunity to continue to advance the Energy Advocates' suggestion through these other planning venues, which will

[1] LC 80 Initial Comments of Energy Advocates at 2
[2] LC 80 Initial Comments of Energy Advocates at 3

be informed by the decarbonization targets and strategies detailed in the CEP/IRP, and which will ultimately tie back to future CEP/IRPs through higher-resolution Community Benefits Indicator (CBI) reporting and consideration.

1.2 Accessibility

On the topic of accessibility, CUB and Energy Advocates emphasized the importance that the CEP is "understandable to non-expert members of the public, particularly for the environmental justice communities."[3] Energy Advocates highlighted some of the goals of this accessibility, including enabling readers to engage in the process, understand CEP actions without digesting the full IRP, or offer feedback on proposals. Staff and Energy Advocates both suggested that an effective means of achieving an understandable CEP is through collaboration with or direct assistance from communities, stakeholders and/or "practitioners with expertise in communicating about energy in more accessible ways."[4]

PGE's response

PGE is on a journey toward increased consistency and quality of engagement with community advocates and members on planning topics. PGE sought to improve the accessibility of the CEP/IRP through inclusion of a first chapter that can stand alone from the rest of the document, and which describes essential context, methodological approaches, and results from the CEP/IRP process, while still adhering to the breadth of CEP guidelines. A reader should not have to read any chapter beyond the first chapter to understand the results of our modeling and how those results inform our action plan to the 2030 targets. Hence the intent of the first chapter supports the Energy Advocates' goal of a "stand-alone roadmap that offers a sufficient understanding of PGE's plans" separate from the longer and more technical material that follows. To progress toward broader accessibility, we have been pursuing and welcome additional venues to communicate about the CEP to communities and the general public.

In developing the CEP/IRP, PGE held seven Community Learning Labs to bring non-traditional and non-technical stakeholders, including community members, into the process. We recognize there is room to improve these collaborations going forward and intend to broaden and continue our engagement process. PGE looks forward to further input from Staff and stakeholders regarding development of effective processes.

1.3 Feedback

On the topic of feedback, Staff and the Energy Advocates indicated that PGE should more clearly record and communicate what feedback and recommendations were received across all engagement venues (including IRP-related engagements as a particular omission), whether or not that feedback was incorporated into the CEP/IRP, and why. Staff observed that with respect to CBIs in particular, PGE had

[3] LC 80 Initial Comments of CUB at 1
[4] LC 80 Initial Comments of Energy Advocates at 2

not clarified which of CBIs proposed through the UM 2225 process were incorporated in PGE's CEP/IRP and the rationale for exclusions.[5]

PGE's response

We value the time that stakeholders put into our planning processes. We recognize that registering and incorporating feedback is central to stakeholders feeling seen and heard. In the short time between development of OPUC CEP guidance and delivery of PGE's inaugural CEP/IRP, we leveraged lessons learned from the DSP to build engagement and feedback processes for the CEP/IRP. Using the Community Learning Labs and surveys is a helpful tool to inform and collect feedback from participants. However, we had low response rates which made it difficult to report back on topics on which we were seeking feedback. We are open to new ideas and collaborating on ways to develop a feedback loop process that improves transparency.

As noted by Staff, the Energy Advocates provided a set of proposed CBIs in Community Lens Straw Proposal Attachment A.[6] The Energy Advocates' contributions helped start the conversation within our Community Learning Labs regarding how to develop CBIs. PGE introduced all the suggested CBIs in a series of Community Learning Labs and focus groups. In the Community Learning Labs and focus groups, we discussed our objectives for CBIs, our approach, our existing work on the DSP and its relationship to the CEP. Through these discussions, additional CBIs were introduced and participants identified the CBIs that are most important in the near-term. Through this iterative work, we prioritized the following top four CBIs in 2023:

- Reduction in the number of customers suffering from high energy burden.
- Low-income and vulnerable communities have access to an increasing number of renewable or non-emitting distributed generation resources.
- Meaningful bilateral engagement between utilities and tribes on siting.
- Improve efficiency and housing stock in the utility service area, including lower-income housing in partnership with Energy Trust of Oregon (ETO).

We started with four CBIs rather than all that were included in Attachment A due to time constraints and a desire to prioritize areas of initial focus based on community input. We have not ruled out any of the identified CBIs and will continue to work with stakeholders to define CBIs and how to incorporate them in the resource planning processes.

Another example, apart from Community Learning Labs, is the incorporation of feedback from other forums into the IRP – Distribution System Planning, IRP Roundtables and Clean Energy Plan spaces.

As discussed in Chapter 14.2.4, PGE took steps throughout the 2023 IRP development to solicit, consider and incorporate stakeholder feedback into the IRP. The feedback process began in March 2021, well

[5] LC 80 Initial Comments of OPUC Staff at 6
[6] OPUC Order No. 22-390, Appendix A at 65 (Attachment A Stakeholder CBI Proposal), available at: https://apps.puc.state.or.us/orders/2022ords/22-390.pdf.

before work started on the 2023 IRP, by engaging stakeholders in a discussion about their values and the IRP process. [7] Once underway, the steps used to build stakeholder feedback into the IRP included:

- Inviting stakeholders to make specific portfolio requests during the 2023 IRP process and we shared those requests at subsequent roundtable meetings.
- Sharing draft information as the analysis unfolded.
- Inviting stakeholders to submit informal comments throughout the process.
- Posting video archives of each meeting and the meeting presentation on our website.
- Publishing comments received via the feedback form, starting in April 2022, and our responses each month to allow all participants to benefit from others' questions.
- Experimenting with different approaches to facilitate the roundtables to encourage equitable participation among stakeholders.

Specific instances where stakeholder feedback was incorporated in the IRP includes, but is not limited to:

- Using a 1.50 inverter loading ratio for hybrid solar-battery resources. The change was in part based on comments received via the IRP feedback form from the April 2022 meeting as well as comments received during that meeting.[8]
- Changing and exploring storage ELCC modeling to try to capture some interactive effects of storage and renewables, including providing ELCC sensitivities on the impact of renewables on storage in the IRP (Appendix J). The change was in part based on comments received during the August 2022 meeting.[9]
- Altering the portfolios studied in portfolio analysis, for example changing the nameplate size of pumped storage hydro in a portfolio sensitivity. The change was in part based on comments received during the November 2022 meeting.[10]
- Changing the methodology used to assess available transmission in the IRP, and the amount of transmission available. The change was in part based on comments received during the August 2022 meeting.[11]
- Stakeholders helped identify the risk factors used in PGE's IRP price model (see discussion on this on page 80 of the 2023 IRP).

[7] See meeting materials from PGE's March 2021 roundtable meeting at https://assets.ctfassets.net/416ywc1laqmd/FYE0Gf8xbQgPZ4To88oZx/9f46ea7c1b93f55c1a0188160273880f/irp-roundtable-march-21-2.pdf
[8] See here: https://portlandgeneral.com/about/who-we-are/resource-planning/combined-cep-and-irp/combined-cep-irp-public-meetings
[9] See here: https://www.youtube.com/watch?v=jKbuy7y6Ky0&t=2822s
[10] See here: https://www.youtube.com/watch?v=U1EjIu7vQqQ&t=11401s
[11] See here: https://www.youtube.com/watch?v=jKbuy7y6Ky0&t=19s

PGE strives to provide easy, transparent access to IRP Roundtable materials and Roundtable archive materials. All IRP Roundtables are recorded, indexed and available online at the link below.[12] PGE also provides responses to Roundtable meeting feedback that is submitted through our website.[13]

PGE understands and appreciates the effort required for stakeholders, especially uncompensated EJ stakeholders, to participate in the CEP/IRP proceedings. We are committed to iterating our effectiveness at detailing the feedback we have received and explaining if, why, and how feedback was incorporated.

1.4 Tribal engagement

On the topic of tribal engagement, RNW and the Energy Advocates advise PGE to engage tribes in a meaningful way and not make it a "check the box exercise." RNW also requests more details on PGE's plan and goals related to community engagement, especially as it pertains to the tribes.

PGE's response

Meaningful engagement of tribes is a key priority for PGE, and an area that we agree is an opportunity for improvement going forward to meet our communities' expectations and align with HB 2021. 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. In April 2023, PGE filled our Tribal Liaison position and the new liaison will be partnering with our Energy Equity Partner to cultivate relationships and collect input from Tribal and Indigenous communities.

At PGE, we believe that effective community engagement is founded in relationships that are long-term, reflect the diversity of the community and continually nurtured. Near-term goals are dominated by activities driven by each regulatory docket, e.g., public meetings. We believe our long-term goals envisioned in this plan foster the high-quality engagement that is necessary to achieve an equitable energy transition. The long-term goals and outcomes are included below for reference:

- Cultivate and maintain trusted and transparent relationships with community-based organizations (CBOs)/community-serving organizations (CSOs), EJ advocates and other community collaborators.
- Build awareness, inform and provide learning opportunities to communities.
- Desired outcomes:
    - Allow greater insights into the CEP and other planning processes needed to achieve decarbonization goals.
    - Co-develop future community solutions and resiliency opportunities such as CBRE projects.
    - Increase community participation, including Tribal and EJ communities.

[12] The recordings include stakeholder questions and feedback: https://portlandgeneral.com/about/who-we-are/resource-planning/combined-cep-and-irp
[13] See here: https://assets.ctfassets.net/416ywc1laqmd/5UAvXSGjPyO6WbAgiGbpDr/3fe0bbd1ba4094521f9785b6c76a006e/Monthly_Feedback_February_2023.pdf

- Demonstrate transparency and accountability.

The CBIAG is an essential contributor to PGE's achievement of its long-term objectives. The CBIAG will provide guidance and direction that promote effectiveness in PGE's community engagement efforts. Progress to date with respect to CBIAG plans is included below:

- Inaugural CBIAG meeting was held on April 26, 2023
- Twelve members of the CBIAG and three open spots. Membership is diverse and representative of a broad array of environmental justice communities. We are actively seeking a tribal representative to fill one of the three remaining open spots, as that perspective is critical to the CBIAG's success
- Public meetings will be held monthly and will discuss topics mandated by HB 2021 and of interest to committee members. We expect the first six months will primarily focus on level-setting
- Members are paid for their time
- Hired a 3rd party facilitator, Espousal Strategies, LLC

1.5 Resilience analysis

Resilience is called out specifically in HB 2021 and has been a common theme throughout CEP and other community engagement. The Energy Advocates expressed support for PGE's efforts in this area and interest in learning more about how resilience-related analysis can support project acquisition. On the topic of resilience-based analyses, the Energy Advocates called for the development of multi-layer maps that can be made public and be used to prioritize resilience and emergency public outreach.[14] Additionally, the Energy Advocates expressed strong support for PGE's incorporation of zone of tolerance concepts in planning and encourage PGE to specifically reference zone of tolerance factors from the Grid Modernization Lab Consortium's (GMLC) resilience report.[15]

PGE's response

PGE sees the potential for alignment between this request and equity mapping conducted as part of the DSP process. PGE intends to continue to explore the Energy Advocates' interest in this topic through the continuing learning labs and other engagement venues.

We will continue to reference the GMLC report, including the zone of tolerance factors, as we refine our approach to resilience across planning venues. We see high value to continued collaboration with stakeholders via forums including Community Learning Labs and OPUC Staff workshops as we seek to develop meaningful screening factors for application of a zone of tolerance.

[14] LC 80 Initial Comments of Energy Advocates at 13
[15] LC 80 Initial Comments of Energy Advocates at 14

1.6 Value of service study

(58) The Energy Advocates expressed interest in PGE's work on value of service analysis. They specifically requested more information regarding PGE's plans to select customers for a dynamic survey instrument design.[16]

PGE's response

PGE has not finalized any plans to update the value of service study. This is a cross-cutting topic, and PGE appreciates that it is of interest to community stakeholders. We will provide updates on the value of service approach through future Community Learning Labs and other community engagement.

1.7 Additional technical workshops

On the topic of technical workshops, the Energy Advocates suggested that it may be useful to have additional technical workshops this year to go over many of the issues involved in transmission planning. Similarly, NewSun advised OPUC to hold a Commissioner workshop focused on transmission issues.[17]

PGE's response

PGE has spent substantial time in the IRP roundtable meeting series describing transmission planning (especially the Transmission Part I – Part IV presentations at the September, October, November and December 2022 IRP roundtable meetings) and we encourage any participants who missed those sessions to rewatch the videos available on our website as time allows.[18]

PGE plans to periodically hold "office hours" sessions 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, we will work with parties to determine how to address them.

Chapter 2. Annual progress

2.1 Demonstrating annual progress

On the topic of measuring progress annually, the Energy Advocates sought further explanation of how procurement of supply-side clean energy resources leads to emissions reductions. They asked that PGE

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[16] LC 80 Initial Comments of Energy Advocates at 13
[17] LC 80 Initial Comments of NewSun Energy at 1
[18] Available here: https://portlandgeneral.com/about/who-we-are/resource-planning/combined-cep-and-irp/combined-cep-irp-public-meetings

express an intent to track continual progress through reported emissions reductions rather than achievement of resource procurement targets.[19]

PGE's response

PGE reports annual emissions via our ODEQ process. We also disclose additional data on greenhouse gas emissions and other sustainability metrics through our annual ESG Report. These are public reports and per UM 2225 guidance, PGE will also provide updates on emissions and progress toward actions outlined in the CEP/IRP Action Plan within IRP and CEP Update filings.

Our CEP/IRP explains that PGE's strategy to reduce emissions while maintaining system reliability is predicated on additions of non-emitting resources and capacity to our system in sufficient quantities to be able to reduce thermal generation associated with sales to retail customers. Resource acquisition is critical to our ability to reduce emissions to achieve the emissions targets in 2030 targets and beyond. For these reasons and consistent with UM 2225 guidance, while PGE will publicly report annual emissions, which will likely reflect year-to-year variability, PGE will also track continual progress in the near term as a function of resource acquisition progress.

2.2 Choice of glidepath

Both RNW and Elizabeth Graser-Lindsey emphasized the importance of earlier reduction of GHG emissions, stating a preference for the front-loaded emission glidepath. A number of reasons were offered to support pursuing the front-loaded glidepath as a more appropriate approach to emission reduction.

PGE's response

PGE assessed the cost and risk tradeoffs associated with a variety of GHG reduction glidepaths that allow us to meet HB 2021 goals on-time, or ahead of targets. Results of this analysis indicated that the linear glidepath provides the best balance of rate of decarbonization with costs and risks. Among the glidepaths that achieve attainment on time, the front-loaded glidepath that accelerates decarbonization increases portfolio 20-yr cost and risk metrics relative to the linear decline. The front loaded glidepath also increases near-term annual cost impacts relative to the linear decline. Additionally, there are unquantified risks associated with the ability to procure resources at the rate required by the front-loaded decline glidepath which would accelerate the already aggressive rate of procurement required to meet HB 2021 targets using a linear glidepath. While there may be benefits associated with the front-loaded decline, the Preferred Portfolio identifies the least-cost least-risk portfolio that PGE considers to be actionable, and the use of a linear-decline glidepath best balances the tradeoffs between rate of decarbonization and portfolio cost and risk.

[19] LC 80 Initial Comments of Energy Advocates at 4

Chapter 3. Resource Options

3.1 Impact of tax credits on DERs

Energy Advocates highlighted a model vintage concern, since PGE did not include the impact of tax credit impacts from the IRA and IIJA on DER costs and adoption within the CEP/IRP. They ask to update the scenario analyses to cover the range of potential IRA impacts.[20]

CUB also noted the importance of customer actions in all pathways to decarbonizing the electricity system and asked for including the impact of IRA and IIJA within the modeling of energy efficiency and demand response. CUB also noted the need for more robust modeling of the long-term benefits of energy efficiency.[21]

PGE's Response

PGE recognizes the concern of DER forecast vintages within the CEP/IRP. PGE notes that for the tax credit impact on energy efficiency, Energy Trust is in the process of reviewing how IRA tax credits might reduce costs. This work is in its infancy and is not captured directly in the Reference Need Future within the CEP/IRP. However, PGE worked with Energy Trust to model higher benefits for EE, and we have included the impact of higher benefits within the Need Futures. As described in the filed CEP/IRP, PGE uses higher and lower Need Futures to evaluate the impact of additional economic or policy drivers not included in the Reference Case.

Similarly, for the remaining DERs (demand response, solar PV, and electrification), the CEP/IRP leans on the DSP, which includes a high adoption case that includes assumptions that make DERs more competitive and accessible. These impacts are captured within the Need Futures as well. Thus, while the tax credit impact of the IRA and IIJA are not explicitly included in the Reference Case, the different Need Futures can provide directional insight on the impact of increased in adoption of DERs. PGE notes that the Company is planning on refreshing portfolio analysis in the LC 80 docket based on a more recent DER forecast that incorporates the impact of these tax credits.

Lastly, PGE notes that while modeling the impact of tax credits on DERs will likely increase the adoption of DERs, DERs that add load such as transportation and building electrification may be offset by DERs that reduce load such as solar PV, demand response, and energy efficiency. Thus, the net impact of the change in DER adoption might not translate to a substantial increase in energy and capacity need.

Lastly, PGE disagrees with CUB's premise that PGE has not conducted robust modeling that accounts for the long-term benefits of EE and DR. PGE has described this analysis within the portfolio analysis chapter, which suggested that increasing EE acquisition both in rate of acquisition and magnitude of acquisition is a strategy to lower costs and risk for customers over the long term. However, as described

[20] LC 80 Initial Comments of Energy Advocates at 8
[21] LC 80 Initial Comments of CUB at 4

in Section 11.4.4 of the CEP/IRP, the near-term price impact of energy efficiency is the primary reason it is excluded from the Action Plan.

3.2 NEM policy

Energy Advocates inquired about the impact of current net metering (NEM) policy on cost shifting and requested PGE provide figures to demonstrate the cost shift caused by NEM.[22]

PGE's Response

PGE has not quantified estimates of the NEM cost shift as part of the CEP/IRP analysis. As described in Section 6.2.1, PGE's analysis of DER adoption was based on methodologies described in detail in the DSP, which included forecasts for behind-the-meter solar based on analysis of customer value proposition inclusive of net metering programs.

3.3 PURPA Qualifying Facilities Contracts

Energy Advocates asked why no PURPA QFs are assumed to renew their contracts with PGE and inquired about whether there is historical data to indicate that no QF contracts will be renewed.[23]

PGE's Response

PGE presented and discussed historical QF renewal rates in the March 2023 CEP/IRP Roundtable meeting.[24] There have been three qualifying facility projects that have renewed. However, all three projects are small (totaling 0.49 MW) and originally signed to 2-year contracts. As a result, these data are not useful in estimating future QF project renewable rates and PGE does not have sufficient data to forecast QF renewal rates.

The CEP/IRP does not assume contract renewals of any kind in the Reference Case. This is largely due to uncertainty about contract renewal terms in comparison to what other options may be available at the time of renewal. If QF contracts are renewed in the future, PGE will adjust forecast of incremental resource needs accordingly.

3.4 Resource cost data

Energy Advocates asked why PGE used the U.S. Energy Information Administration's Annual Energy Outlook (AEO) 2020 vintage for creating inputs of costs and characteristics for supply side resources rather than more current vintages.[25]

[22] LC 80 Initial Comments of Energy Advocates at 6
[23] LC 80 Initial Comments of Energy Advocates at 6
[24] See slide 58. Available at https://portlandgeneral.com/about/who-we-are/resource-planning/integrated-resource-planning/irp-public-meetings
[25] LC 80 Initial Comments of Energy Advocates at 8

PGE's Response

PGE's CEP/IRP analysis relied on many sources of input data, many of which are updated annually. The IRP team must freeze the data inputs at a certain point and conduct analysis with the vintages that have been incorporated into models at that point in time. Like other sources of input data, the AEO vintage was frozen before the release of subsequent vintages to allow modeling to take place. When this occurred, the 2020 AEO vintage was the most recent available. Such an update could change overall cost estimates, but not the resource plan itself because while specific cost estimates may have changed across vintages, the general cost trends and relative resource economics have not.

3.5 Offshore wind discussion

RNW suggests that offshore wind merits additional discussion with greater granularity and detail around transmission infrastructure required to support the resource. They also suggest a scenario that considers offshore wind and an RTO together.[26,27]

PGE's Response

PGE agrees that offshore wind is an intriguing resource option that has the potential to provide high capacity factors and capacity contribution to PGE's system. The potential benefits of offshore wind were studied in the CEP/IRP through the inclusion of the offshore wind portfolio in the emerging technologies portfolio group. Portfolios were designed to isolate the impact of individual resource actions relative to default assumptions; the inclusion of a combined offshore wind and RTO portfolio does not fit within the study design and would not provide additional insights beyond those of the separate offshore wind and RTO portfolios.

While considerable offshore wind resource development activity is underway, there is substantial uncertainty about the timing of commercially viable projects. Portfolio analysis in the 2023 CEP/IRP focuses on the resources required to meet 2030 emission reduction targets, but offshore wind is not expected to be available until after 2030. There is substantial uncertainty surrounding the mix of resources that will be available after 2030, and a variety of these promising resources, including offshore wind, are discussed in-depth qualitatively in Chapter 8 of the CEP/IRP.

3.6 Pumped hydro characteristics

The Swan Lake and Goldendale pumped storage projects ("Projects") provided comments regarding the assumptions PGE made about resource characteristics of the pumped hydro proxy resource modeled in the 2023 CEP/IRP.

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[26] LC 80 Initial Comments of RNW at 8

[27] PGE notes that in their comment RNW refers to an assumption of 960 MW of offshore wind in the Brookings call area as a renewable resource proxy, which is not consistent with PGE's modeling assumptions in the CEP/IRP. PGE assumed 500 MW of available offshore wind, as described in Chapter 11 of the CEP/IRP.

The Projects claim that PGE either leaves out or relies on incorrect assumptions for pumped storage throughout the CEP/IRP. The Projects specifically point to the omission of pumped storage from tuned system ELCCs, resource capacity contribution, and capacity value. The Projects also question the validity of pumped storage having a greater rate of decline in ELCC value in winter than summer.[28]

The Projects suggest that inappropriate assumptions were made regarding owners cost allowance and that input data vintages are out of date.[29] They also question the appropriateness of PGE's assumptions regarding the useful life of pumped storage projects and question whether pumped storage received the proper tax incentives. The results of these assumptions, they assert, is to unfairly favor batteries relative pumped storage in modeling.[30]

Finally, the Projects disagree with the inclusion of pumped storage in the emerging technology group of portfolio analysis and ask PGE to re-analyze the Preferred Portfolio with access to pumped storage.[31]

PGE's Response

PGE agrees that it erred in omitting values for pumped storage in the following locations: 1) tuned system ELCCs in Appendix K; 2) resource capacity contribution in Section 10.5; and 3) capacity value in Section 10.6. The tuned ELCC values, which would have been in Appendix K, Table 133, are shown below in **Table 1**. The untuned season pumped storage hydro ELCC values, which would have been in Chapter 10.5, Table 50, are 111% in the summer, 80% in the winter (100 MW nameplate of resource). The capacity value from Section 10.6, Table 51 would have been $136.80/kw-year for 100 MW of resource.

Table 1. Pumped hydro annual tuned system ELCCs for 100 MW of nameplate resource additions

2026-2043 average	2026	2027	2028	2029	2030	2031	2032	2033	2034
106%	97%	99%	101%	103%	105%	106%	107%	108%	108%
	2035	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**
	109%	110%	110%	110%	109%	109%	109%	109%	108%

Pumped storage hydro has a greater rate of ELCC decline in the winter than the summer in the 2023 PGE CEP/IRP. Part of this is not due to the winter rate of decline, but the robustness (and minimal decline) of the summer ELCC curve. Pumped storage hydro, along with all other storage resources tested, has a higher summer ELCC value at every nameplate increment tested. One driver of this is that summer adequacy challenges are relatively concentrated into the evening hours, whereas winter adequacy

28 LC 80 Initial Comments of Swan Lake and Goldendale at 5-6
29 LC 80 Initial Comments of Swan Lake and Goldendale at 5-6
30 LC 80 Initial Comments of Swan Lake and Goldendale at 13-15
31 LC 80 Initial Comments of Swan Lake and Goldendale at 3-5

challenges are spread over a greater number of hours. As a result, storage resources may face greater energy limits (the ability to recharge) in the winter as compared to summer. This is illustrated in Chapter 6.6, Figure 44.

PGE's assumptions regarding useful life, cost accounting, and tax incentives are valid and well justified. PGE assumes a useful life of 38 years for pumped hydro in the 2023 CEP/IRP. This assumption was provided by the engineering firm HDR and is the same as was used in modeling of PGE's acknowledged 2019 IRP. As identified in the comments from the Projects, there are a wide range of estimates of economic life of pumped hydro facilities in the literature and PGE's assumption falls within the range identified. While PGE does not dispute the claim by the Projects that it is possible for a pumped hydro project to have a useful life beyond 38 years, selecting the most optimistic useful life is not necessary to put pumped hydro on an equal footing with other proxy resources because PGE does not determine useful life of those resources by assuming the most optimistic potential lifespan for the modeling of any resources.

Although not shown in the subset of modeled resources displayed in Figure 14 of the CEP/IRP, PGE did account for the IRA tax credit for all energy storage resources with a 30% ITC included in the calculation of pumped hydro storage costs. Owner's costs are included for supply-side resources as part of the capital costs sourced from NREL or EIA. Based on review of other published data available at the time (e.g., Burns & McDonnell study for PacifiCorp 2021 IRP), NWPCC cost estimates were similar to the reviewed EPC project costs w/o owner's allowance. The Burns & McDonnell study applied a 15-20% allowance for owner's costs. PGE's cost estimates use 20%. The HDR study for PGE's 2019 IRP applied a 25% owner's allowance to the EPC costs. Variations in capital cost trajectories are also captured in the CEP/IRP through the use of high and low capital cost sensitivities.

PGE chose to group the pumped hydro portfolio with emerging technologies because PGE has never had the resource in our resource mix. However, CEP/IRP results are not prescriptive with respect to supply-side resource procurement. During the competitive procurement process, PGE anticipates that bidders will employ their expertise to develop the most cost competitive offerings for specific resources, and PGE will select the best set of resources to maintain reliability, minimize costs, and reduce emissions.

PGE elected to not include the option of pumped-hydro storage for the Preferred Portfolio because initial results never included the near-term selection of the resource. However, to inform this response we re-analyzed the Preferred Portfolio with 333 MW of pumped hydro available for selection starting in 2028. Results from this analysis show that the model only selected the resource of pumped hydro in 2040. This finding demonstrates the omission of pumped hydro from the Preferred Portfolio did not influence the pre-2030 resource buildout on which PGE focused the analysis, or Action Plan for which PGE is seeking acknowledgement.

Chapter 4. Energy Efficiency and Demand Response

4.1 Approach to Energy Efficiency and Demand Response

On the topic of how PGE approached and decided on the actions impacting energy efficiency (EE) and demand response (DR), Staff asked about how PGE's modeling addressed direction from HB 2021 to consider EE DR resources in addition to non-emitting resources.[32] Regarding not including additional EE in the Preferred Portfolio, Staff asked why PGE prioritized short-term cost impacts over long-term reductions and requested additional details on execution risk mentioned. [33] Staff also asked how PGE considered Senate Bill 1547 (ORS 757.054(3)) deciding on the role of additional EE.[34] Lastly, Staff asked for justification for not including additional EE in the Preferred Portfolio.[35]

PGE's response

In the 2023 CEP/IRP, PGE evaluated non-emitting resources, energy efficiency and demand response to meet clean energy targets set forth in HB 2021. Non-emitting supply side resources were developed based using publicly available cost data and evaluated through portfolio analysis, like in previous IRPs. PGE also focused on non-emitting resources including resources that may require transmission expansion beyond the current transmission system's capacity.

For energy efficiency, PGE built on the processes used in prior IRPs to evaluate the technical achievable potential of EE. The technical achievable potential of EE is the sum of the cost-effective and non-cost-effective potential (or additional EE). For the cost-effective potential, PGE reduced the load forecast by the cost-effective quantities of energy efficiency as determined by Energy Trust. This in turn impacts the energy and capacity position that influence resource buildouts within each portfolio. Then, for the non-cost-effective potential/additional EE, PGE evaluated this by bundling the measures and introducing them within portfolio analysis as a new resource option. Combined, these two processes represent PGE's approach to modeling the technical achievable potential of energy efficiency developed by Energy Trust of Oregon.

For demand response, PGE leveraged the technical achievable potential from the Distribution System Plan, which includes the cost-effective and non-cost-effective demand response potential. The cost-effective quantities were included our resource adequacy model (Sequoia) to influence the capacity need and thus the resource buildout in each portfolio. The remaining technical achievable potential was introduced as a new resource option. Combined, these two processes represent PGE's approach to

[32] LC 80 Initial Comments of Staff at 9
[33] LC 80 Initial Comments of Staff at 4
[34] LC 80 Initial Comments of Staff at 4
[35] LC 80 Initial Comments of Staff at 4

modeling the technical achievable potential of demand response developed by the Distribution System Plan.

Regarding Staff's question on why PGE did not limit its decision-making to long-term cost and risk metrics when considering different portfolios, PGE notes that IRP metrics of cost, variability, and severity as well as community benefits and decarbonization were considered for each portfolio. However, PGE also scrutinized portfolios that have different dimensions of cost and risk. For example, procurement risks that could result in non-compliance of HB2021 were a non-quantitative risk considered for the "Back-loaded decline" decarbonization glidepath portfolio. While this risk is present in all portfolios and not part of the metrics provided, it is important to consider when determining Preferred Portfolio. Similarly, when considering the additional energy efficiency portfolios PGE considered the unique implication of these resources on near term rates.

PGE provides the following explanation for the exclusion of additional EE from the Preferred Portfolio. Portfolio analysis suggests there are long-term cost and risk reduction benefits stemming from including additional quantities of EE beyond what was previously deemed cost-effective. The beneficial properties of EE such as its capacity contribution and energy value, especially relative to the costs associated with alternative procurement options, make some additional quantities of EE an attractive resource option. However, when looking at the near-term price impact, additional consideration is warranted. Two current policies influence the near-term rate pressure when acquiring additional quantities of EE and DR. First, EE is neither financed nor securitized, so the full cost is incurred before any benefits accrue. This is different compared to other resource options, where benefits and costs accrue over time. Second, EE can have the effect of increasing the costs per unit of sales because it results in decreased total retail sales. PGE recognizes that different rate mechanisms could reduce the influence of the near-term price impact. Other supply side resources do not decrease retail sales. Both effects lead to the increased near-term cost pressure for customers, depicted in the CEP/IRP's Figure 93.

While these policies and their impacts on customers have been in place for many years, there are nuances unique to the 2023 CEP/IRP that increase the risk of including additional EE in PGE's Preferred Portfolio. Historically Energy Trust has acquired relatively consistent quantities of energy efficiency year over year, ramping up slowly over multiple years. This slow ramp has helped manage the short-term rate impact by ensuring customers only see a small change in rates each year. The increased execution risk of deviating from this slow ramp is discussed below in **Section 4.3** of these comments. Second, the results from portfolio analysis show there is value in increasing energy efficiency acquisition and doing so quickly. This would require a faster ramp up in costs and quantities of EE acquired, which though beneficial for customers in the long term would increase near-term rate pressure more than these policies practices have in the past. Thus, in the absence of the slow ramp that helped has tempered the rate pressure in the past, a step change in energy efficiency would result in immediate rate pressure.

Addressing these barriers by amending current policy to alleviate this near-term cost pressure could make the Additional EE resource more attractive to PGE.

In addition to the near-term cost impact, PGE further describes the execution risk as follows: In the CEP/IRP, PGE has included Energy Trust of Oregon's forecasted energy efficiency of 216MWa from 2024 through 2030. Of that, 156 MWa is expected from 2026 through 2030. The execution risk is introduced when PGE considers the 50 MWa of additional EE, during the same period. This would not only increase targets by ~30% but also require significant organizational scaling by the ETO and its partners but also require this increase in capacity for a short period, through 2030, a risk they may not be willing to take. Thus, there is a potential procurement risk. The compounded impact of customers incurring the costs upfront combined with the procurement risk described above constitute the execution risk.

Lastly, Senate Bill 1547(ORS 757.054 (3)) states that electric utilities must pursue all available EE and DR resources that are cost-effective, reliable, and feasible. Determining the quantities of EE that is feasible and cost-effective occurs during the Energy Trust budget setting process. The feasibility of pursuing EE in years past has been determined based on a combination of factors including Energy Trust's ability to achieve those savings and rate impact considerations. The analysis of additional EE in the IRP moves that discussion from the Energy Trust budgeting process to the CEP/IRP docket.

4.2 Energy Efficiency and Demand Response Portfolio Modeling

In two related comments regarding the modeling of additional EE in the IRP, Staff suggested that PGE develop a new portfolio that mimics the Preferred Portfolio but with 50 MWa of additional EE. Staff also asked PGE to alter the Preferred Portfolio to include 50 MWa of additional EE and not force in the South of Alston upgrade.[36] Additionally, Staff noted the differences between the construction of portfolios that tested varying amounts of additional EE and the Preferred Portfolio, which makes them difficult to compare.[37] Lastly, Staff asked for the price impact results of the 50 MWa additional EE portfolio.[38] Energy Advocates asked for more clarification on the interaction between DERs and transmission constraints.[39]

PGE's response

PGE is concerned with Staff's direction to model additional portfolio analysis to compare the additional EE portfolio to the Preferred Portfolio. Portfolio groups were designed to test specific actions regarding resource additions or other modeling changes within groups to isolate the impacts related to the key planning issues identified in the 2023 CEP/IRP (i.e., rate of decarbonization, transmission, DERs, CBREs, etc.). The isolated impact of these actions can be seen by comparing portfolios within each group. Accordingly, it is not helpful to understand specific choices by comparing the Preferred Portfolio to the EE portfolios.[40]

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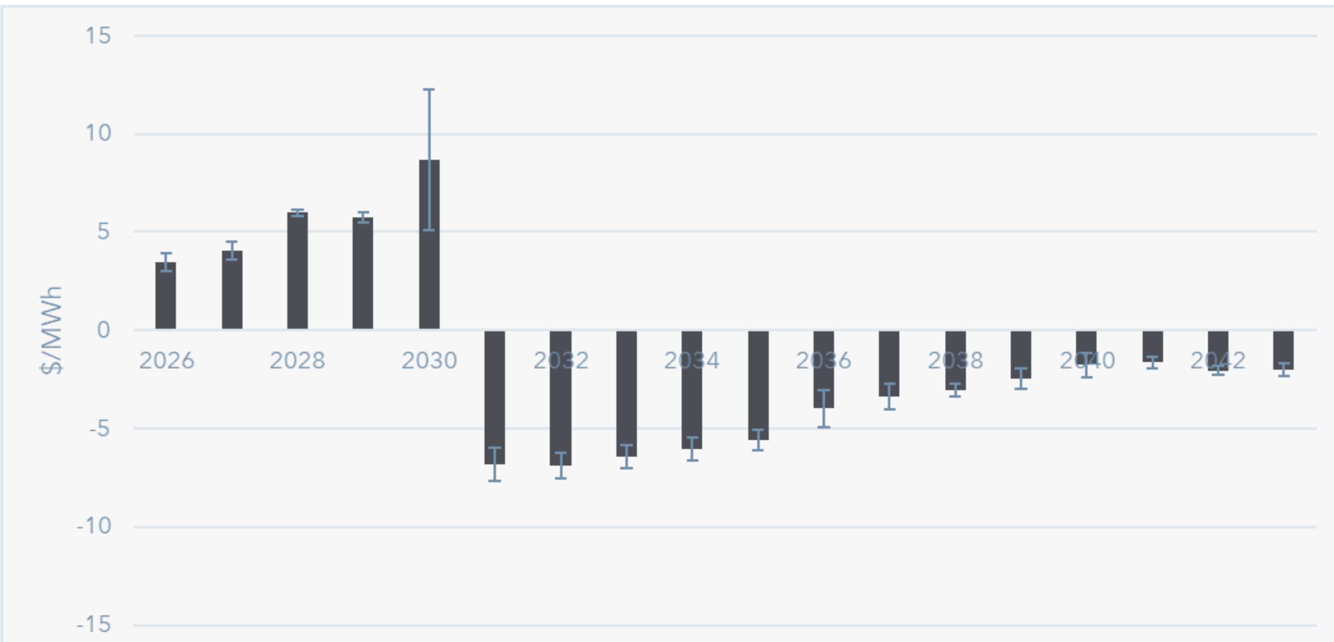
[36] LC 80 Initial Comments of Staff at 4
[37] LC 80 Initial Comments of Staff at 4
[38] LC 80 Initial Comments of Staff at 4
[39] LC 80 Initial Comments of Energy Advocates at 9
[40] The impact of 50 MWa of additional EE was studied in the EE portfolios group, where adding 50 MWa of additional EE decreases portfolio cost and risk metrics. Similarly, it is not necessary to remove the forcing of the SoA upgrade from the Preferred Portfolio in order to identify the benefits of additional EE. The benefits of additional EE to long-term portfolio

PGE notes that portfolio analysis found that when considering transmission constraints, EE can lower portfolio cost and risk. This finding, which highlights the potential benefits that EE can provide in alleviating transmission needs, is discussed in Chapter 12 Portfolio Analysis. That the Optimized EE portfolio selected 53 MWa of additional EE suggests that offsetting transmission need with up to 53 MWa of additional EE could reduce long-run portfolio costs.

Figure 1 highlights the difference in price impact between a portfolio with Zero addition EE and 50 MWa of additional EE. The 2030 impact would be $9/MWh higher on average than the portfolio with zero additional EE. This translates to ~10% in the costs associated with generation resources relative to a portfolio without additional EE. Relative to 2024, in 2030 the 50 MWa EE portfolio is sees ~19% higher costs associated with generation resources relative to an ~8% increase in costs associated with generation resources for the portfolio with no additional EE.

Figure 1. Price Impact difference between Zero Additional EE and 50 MWa of additional EE



4.3 Energy Efficiency and Demand Response in the Action Plan

On the topic of Customer Actions, Staff ask if there is a discrepancy in the CEP/IRP since the Action Plan does not include non-cost-effective DR resources even though PGE's CEP/IRP states that "…the IRP

cost and risk are clear from analysis in the EE portfolio group. Despite the benefits to long-term portfolio cost and risk metrics, additional EE was not included in the Preferred Portfolio because of near-term cost impacts as described above and visualized through analysis in PGE's ART model.

Action Plan sets a target that combines both the cost-effective and currently non-cost-effective resources."[41]

Energy Advocates ask for more details on EE and DR numbers in Table 69, along with other execution elements including the role of Energy Trust (ETO), how PGE supports ETO, past track records of resource acquisition, and contingencies if these resources are not acquired or perform in a timely manner.[42]

PGE's response

PGE understands how the sentence quoted above by Staff is confusing; we clarify that no additional (non-cost-effective) DR was included in the 2023 CEP/IRP Action Plan. PGE also clarifies that the CEP/IRP's Table 69 represents Energy Trust's forecast of the quantity of energy efficiency they expect to procure for PGE customers.

Table 2 below shows projected versus achieved EE savings. Reviewing the 2016 IRP Action Plan to actuals, from 2017 through 2020, Energy Trust achieved 133.6 MWa of the 135 Mwa target. A key consideration here is that the last year of the Action Plan was 2020, when the COVID 19 pandemic struck, resulting in Energy Trust achieving 87% of their target. Reviewing the 2019 IRP Action Plan from 2021 through 2025 to actuals, Energy Trust has achieved 91% of their pre-pandemic target thus far, achieving 80.3 MWa. While this shows that Energy Trust has very consistently met their goals, there is increased execution risk with considering additional EE because it would not only increase targets by ~30% but also require significant and rapid organizational scaling by the ETO and other partners, which introduces a potential procurement risk.

Table 2. Comparing Energy Trust's EE acquisition by year against different forecasts

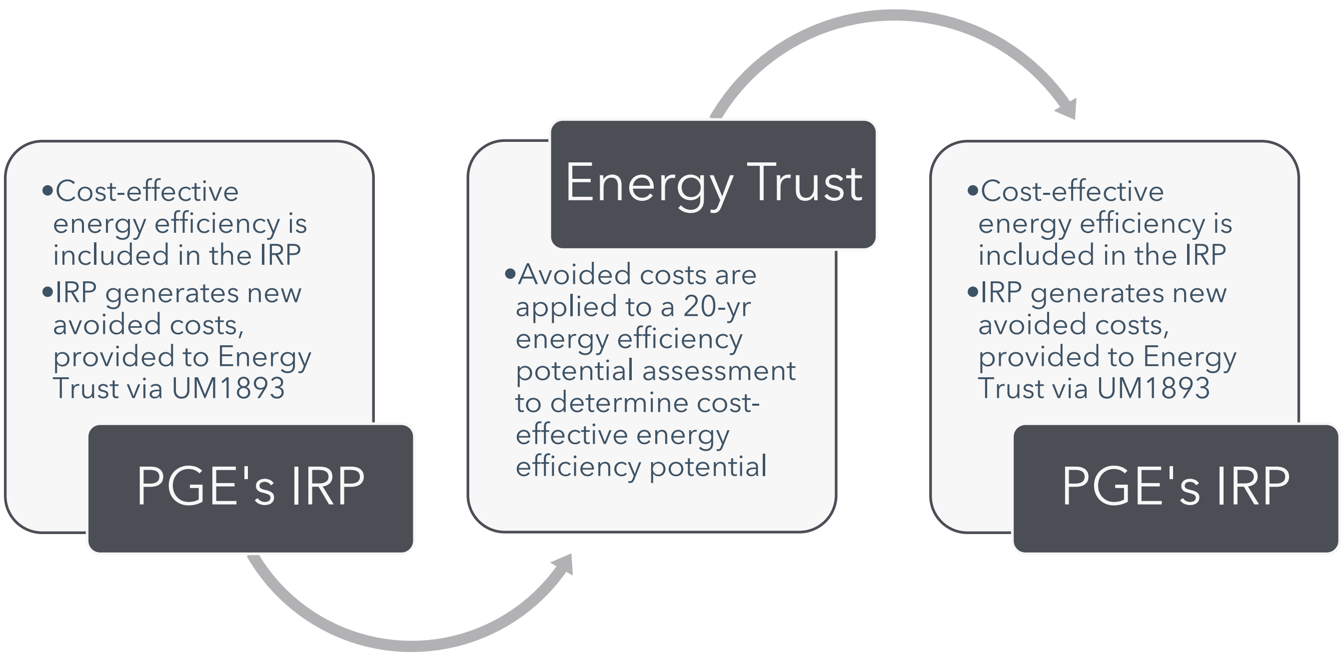
Year	Parameter	PGE Budget[43]	2016 IRP[44]	2019 IRP[45]
2017	Actual (MWa)	40.4		
	Goal (MWa)	35	36.6	
	Achieved (%)	115	110	
2018	Actual (MWa)	34.7		
	Goal (MWa)	36.4	35.5	

[41] LC 80 Initial Comments of Staff at 10
[42] LC 80 Initial Comments of Energy Advocates at 11 and 12
[43] Provided by Energy Trust as part of the data request on 2/9/2023
[44] The cost-effective EE forecast from the 2016 IRP is available at: https://downloads.ctfassets.net/416ywc1laqmd/1y737MdERELNLNyWAW8bw2/3f150507210f0fba46276de38c0afdfa/2016-irp.pdf#page=161
[45] The cost-effective EE forecast from the 2019 IRP is available at: https://downloads.ctfassets.net/416ywc1laqmd/6KTPcOKFlLvXpf18xKNseh/271b9b966c913703a5126b2e7bbbc37a/2019-Integrated-Resource-Plan.pdf#page=95

	Achieved (%)	95	98	
2019	Actual (MWa)	32.8		
	Goal (MWa)	33.5	33.6	
	Achieved (%)	98%	98%	
2020	Actual (MWa)	25.7		
	Goal (MWa)	27.4	29.5	30.4
	Achieved (%)	94%	87%	85%
2021	Actual (MWa)	24.2		
	Goal (MWa)	26.3	27.1	29.5
	Achieved (%)	92	89	82
2022	Actual (MWa)	30.4		
	Goal (MWa)	29	24.4	28.3
	Achieved (%)	105	125	107
	Parameter	**PGE Budget**	**PGE 2016 IRP**	**PGE 2019 IRP**
	Actual (MWa)	31.4	31.4	26.8
Average	Goal (MWa)	31.3	31.1	29.4
	Achieved (%)	100	101	91

The cyclical planning interaction between Energy Trust and PGE is shown in **Figure 2**.

Figure 2. The cyclical planning interaction between PGE and Energy Trust



Energy Trust's role as statewide EE program administrator is to steward PGE customer dollars to realize savings for industrial, agricultural, commercial, and residential customers. The majority of PGE customer dollars that contribute to Energy Trust's annual budget are ultimately provided to customers in the form of incentives. PGE supports Energy Trust via promotion (marketing and outreach funded from SB 838) and via Action Plan collaboration. Comprehensive Action Plans breakdown activities by customer program segment, Existing Buildings, Industrial & Agricultural, Residential, New Buildings, and Northwest Energy Efficiency Alliance (NEEA) funding, and support conservation measures including space and water heating and cooling, insulation, lighting, variable frequency drives, motors, refrigeration, wastewater treatment and custom incentives and strategic energy management as well as early design assistance and make-ready infrastructure. Utility-specific Action Plans, born out of House Bill (HB) 3141, go a step further to represent areas of joint investment and coordinate activity and are supported by workgroups – Community Engagement, Marketing and Outreach, Renewables, and Non-Wires Solutions - comprised of Energy Trust and PGE staff with charters that clearly articulate objectives and milestones.

Regarding demand response, the DR additions forecasted are expected to be procured through PGE's existing and new demand response programs. Details on the budget, approach, and cost-effectiveness of these programs have previously been published in the Multi-year Flexible Load plan.[46]

PGE appreciates the concerns raised by Energy Advocates regarding risks and contingencies related to meeting forecasted DR targets. PGE minimizes this risk by first piloting these programs. The results are then evaluated by a third party which accounts for the impact of customers that have enrolled but did not participate. This minimizes the risk of the program underdelivering when dispatched during operations. If the DR program is unable to meet its targets and the RFP is not informed of this risk in time, and the load is high enough that the system cannot be managed by other resources, PGE will look to the wholesale market to cover that need. This final backstop exposes customers to potentially higher market prices and likely increased emissions.

However, PGE is working with customers and partners to develop DR programs based on market research and other factors to ensure these targets are met. Often the primary strategy to increase participation is incentivizing customers. These decisions have previously been made downstream of the IRP process in the Multiyear Flexible Load plan.

Chapter 5. Community Benefits Indicators

5.1 CBI selection

Community Benefits Indicators (CBIs) were addressed in initial comments by Staff, Energy Advocates and RNW. Regarding selection of CBIs, Staff sought further explanation from PGE on the portfolio CBI (pCBI) and resource CBI (rCBI) approach and additional clarity on how these indicators map to the five CBI categories articulated in the CEP guidance adopted by OPUC.[47]

PGE's response

The 2023 CEP/IRP is PGE's first attempt at developing an approach to consider CBIs directly in planning. Given the limited time following adoption of OPUC guidance in late 2022, PGE took a broad approach to both the rCBI and pCBI used in portfolio analysis. The rCBI and pCBI used by PGE represent the aggregate impact of community benefits generated at the resource and portfolio levels. This could represent a single benefit for some CBREs or the aggregated impact of several benefits for other CBREs.

As Staff rightly mentioned in their comments, the community benefits of CBREs depend on several factors including where the CBREs are sited, who owns them and/or benefits from them financially, how they are built, how they support the community during outages, and how they support the community in

[46] The Multi-year flexible load plan has previously served as the equivalent function to the combined process of UM1893 and Energy Trust's budget process for EE
[47] OPUC Order No. 22-390, Attachment 1 at 4.

other ways.[48] Thus, the type and quantity of benefit is specific to a unique combination of factors. Defining each combination of factors specific to each benefit would result in many permutations that are impractical to quantify in a generalized manner consistent with other proxy resources. PGE is open to working with and codeveloping future proxy resources that maybe more specific with our community partners.

As an illustrative example to show how the benefits are a function of several factors - A solar CBRE at a public school could direct revenue benefits to the community members, thereby reducing energy burden. Alternatively, they could use that benefit to reduce costs at the school, reducing its costs but not reducing community electricity burden. Similarly, a microgrid at a substation could provide resiliency benefits through reduced outages or reduced duration of outages because of its location, whereas a microgrid downstream of the feeder could act as a community hub during emergencies but not provide any outage reduction benefits to surrounding buildings. Thus, our approach of estimating the aggregate benefit of a CBRE as a proxy resource category for expected but unknown benefits that accrue to society, promotes a balance in which:

1. The IRP is not under valuing CBREs, and

2. The IRP is not overly prescriptive in their expected benefits of CBRE, which could limit procurement flexibility of resulting resource acquisition activities

Looking forward, PGE expects the CBRE RFP will be a key source of learning opportunities to inform the planning evolution of CBIs and their impact on CBREs.

5.2 CBI valuation

On the topic of CBI development and calculation, Energy Advocates posed questions regarding the development of rCBIs in portfolio analysis and their application to CBREs. The Energy Advocates and RNW sought further explanation of the basis for PGE's 10% rCBI valuation and the scope and approach to valuing benefits of CBREs to PGE and its communities.[49,50] Additionally, Energy Advocates requested clarification of the interpretation of specific values in PGE's sample calculation for the net cost of a microgrid incorporating rCBI benefits. [51]

PGE's Response

To determine the impact of CBIs on resource economics, PGE based its 10% rCBI valuation on the company's existing practice for valuing EE, which allows for EE to be considered cost-effective even if it is 10% higher in cost than an otherwise reasonably available resource. This is a common practice regionally within energy efficiency to include a 10% cost reduction as a benefit. Use of the 10% adder for CBREs allows us to apply a transparent methodology that is already familiar to Oregon energy

[48] LC 80 Initial Comments of Staff at 6
[49] LC 80 Initial Comments of Energy Advocates at
[50] P10, https://edocs.puc.state.or.us/efdocs/HAC/lc80hac74848.pdf
[51] LC 80 Initial Comments of Energy Advocates at 7 and 10

stakeholders. The reasoning to adopt this aggregated approach was also described in these PGE comments in **Section 5.1, CBI selection**.

When valuing the economics of CBREs, PGE considered both the aggregate impact of all benefits that are applicable to supply side options and rCBI benefits only are only applicable to CBREs. In calculating costs, PGE also considered the impacts of tax credits that offset costs. Thus, the benefits not only include those that accrue to customers via the grid such as capacity, energy, and flexibility, but also benefits that accrue to society through the rCBI which represents the aggregate impact of expected but unknown benefits of CBREs.

PGE appreciates the Energy Advocates' request for clarification regarding the value of rCBI credit applied in the CEP/IRP's Figure 77. To determine the value of the rCBI (which is shown as $22/kW-yr), PGE first reviewed the costs and potentials of the three CBREs considered in the IRP– solar, microgrid, and small in-conduit hydropower. To prevent the rCBI from being directly correlated with cost, PGE determined the average cost (without tax credits) and weighted it by the MW potential from 2026 through 2030. The 10% CBI benefit is then applied to this weighted average value. Thus, a single rCBI value is used for all CBREs based on the total portfolio of CBREs and prevent the economics to be skewed towards more expensive resources given the large cost spread. **Table 3** provides the calculation:

Table 3. Calculating the rCBI value

CBRE	Total Potential from 2026-2030 (MW)	Average Cost from 2026-2030 ($/kW-yr) without tax credits
Solar	50	166
Microgrid	100	215
In-conduit hydro	5	775
Weighted average value		= ((50*166) +(100*215) +(5*775)) / (50+100+5)
		= 217
CBI credit		$21.7/kW-yr

PGE expects the CBRE RFP to provide insights on CBI valuation and how they should evolve with future planning cycles. Specifically, PGE will aim to glean insights on the types of benefits that can be quantified, the methods of their inclusion in future CEP/IRPs, and the magnitude of the benefits and the rate of accrual to customers.

5.3 Informational CBIs (iCBIs)

The Energy Advocates expressed appreciation for PGE's work through the Community Learning Lab process to collaborate with communities on developing initial CBIs. Looking ahead to continued development of CBIs, they encourage PGE to clarify how iCBIs will be defined and measured, including baselines for specific indicators. The Energy Advocates also question how PGE can differentiate between community benefits achieved through activities directly resulting from HB 2021 and the CEP process, as compared to benefits achieved by other PGE and OPUC initiatives.[52]

Additionally, Energy Advocates and RNW call attention to PGE's environmental iCBI specifically and recommend incorporation of a new environmental CBI that recognizes tribal priorities. Specifically, the Energy Advocates suggest a metric for "PGE's purchases of power that is generated from the Columbia River hydro system."[53,54]

PGE's response

On the baseline for informational CBIs (iCBIs), PGE expects to continue working collaboratively with stakeholders through ongoing Community Learning Labs and other engagement venues to develop methodologies associated with these CBIs.

Regarding the attribution of benefits across different policies, PGE is open to continuing exploration of this topic through community engagement, but at this point we view progress toward community benefits as the combined outcome of all PGE efforts as more important than detailed attribution to one policy or plan alone. PGE's CEP/IRP sets a high-level roadmap for the HB 2021 goals and informs many of the utility's other activities.

In response to the suggestion of adding a new iCBI, we are not formally modifying the iCBI list included in the CEP/IRP via this response process, but we view the initial list as a starting point for continued iteration in future planning processes. Our intent is to use future Community Learning Lab sessions to consider additions and refinements to the CBIs, as discussed in these comments in **Section 1.3, Feedback**. Consideration of an indicator for Columbia River hydro may be able to leverage significant existing work by Energy Trust and the Northwest Power and Conservation Council related to valuation of water-related non-energy benefits linked to specific energy efficiency measures (e.g., improved on-farm irrigation to keep more water in stream). More generally, as discussed in these comments in **Section 1.4, Tribal engagement**, PGE's new Tribal energy liaison will be a key partner in bringing tribal perspectives into the CEP/IRP and other planning venues.

[52] LC 80 Initial Comments of Energy Advocates at 7
[53] LC 80 Initial Comments of Energy Advocates at 7
[54] LC 80 Initial Comments of RNW at 10

Chapter 6. Community Based Renewable Energy

6.1 CBRE acquisition and community participation

On the topic of EJ community participation in the CBRE acquisition process, Staff and the Energy Advocates emphasized the need to have a process that:

- Includes actual community members, not just CBOs/CSOs;
- Is accessible to community members, not just QF developers; and
- Includes community input beyond just the development of a scoring matrix.

PGE's response

We recognize that the pursuit of CBREs is an opportunity to increase and diversify engagement with community partners. PGE anticipates working directly with communities to develop an acquisition process, such as a request for proposals (RFP). As part of that process, PGE anticipates co-development of the metrics and methodology behind scoring and product definition. The process will provide an opportunity for projects to propose how they will provide a community benefit, and PGE and communities together will determine which projects provide the optimal value.

We plan to form a workgroup to assist with development of an acquisition process, including the scoring matrix, and we anticipate that this group will be comprised of both community members and PGE employees. We intend to leverage assistance from our community partners who attend our Community Learning Labs and connect with our CBIAG members to refer/recommend organizations/people who represent EJ communities to participate in our RFP workgroup. Also, PGE will seek people who represent EJ communities through other engagement activities (e.g., community events, neighborhood associations, local CBOs/CSOs). PGE is currently planning an outreach and engagement process that will run throughout 2023. We would welcome additional guidance from entities such as Energy Advocates. In addition to the scoring matrix, PGE plans to engage communities to develop multiple aspects of the acquisition process, including community outreach expectations of potential bidders, and timing and process.

In addition, PGE anticipates additional efforts in 2023 to acquire CBRE resources (including potential programs) that can help increase accessibility of project and/or community benefits that may not have been bid into a potential RFP. PGE plans to leverage the learnings and iterate all CBRE acquisition efforts to determine how to increase accessibility as we acquire CBREs toward the 2026 and 2030 targets.

We look forward to discussions with the community about how to monitor and measure the effectiveness of the community RFP as this will be our first attempt at a community RFP. We anticipate that this inaugural community RFP effort will create a foundation for future efforts, providing learning opportunities for all parties involved. We expect that the process will enable PGE to build more and stronger relationships with community participants and start building contact lists for future initiatives.

6.2 CBRE acquisition

Staff and the Energy Advocates inquired whether the RFP was the only route for CBRE acquisition and what might be done to support community-based organizations who lack the resources or expertise to propose resources within a CBRE RFP process.[55] Additionally, NewSun sought clarification as to whether PGE's CBRE acquisition would include larger scale, transmission-interconnected resources.[56]

PGE's response

PGE anticipates that an RFP would include PGE and communities co-developing a process to acquire CBRE resources that meet community needs and preferences. In addition to that process, PGE anticipates additional procurement pathways through retail programs designed to increase accessibility and ensure CBRE acquisition that allows additional community-directed acquisition. The different pathways for acquiring CBRE resources include:

Request For Proposals (RFP): PGE plans to co-develop a competitive solicitation – together with communities – that will allow projects to bid and propose how they will provide benefits to the community. These benefits could be through ownership structure, resiliency, workforce development, or a variety of other proposals. Communities will prioritize which benefits and projects are best positioned to meet the intended outcome of this first acquisition process.

Retail Programs: PGE plans to continue developing programs built on collaboration between PGE and communities. While an RFP serves as an open call to the market of renewable resources, programs will serve as a more targeted opportunity to increase accessibility and meet specific locational, technology, or ownership outcomes.

Bilateral acquisition: PGE could work directly with communities to identify and acquire projects that provide a particularly compelling value proposition.

Request for Information (RFI): PGE may initiate an RFI to better understand potential barriers to participation, to forecast potential technologies and locations that may work well in future CBRE acquisition processes, and to identify enabling actions that PGE could take to accelerate CBRE acquisition in the future.

Finally, PGE responds to NewSun's question regarding whether CBRE acquisition would include larger scale, transmission-interconnected resources. Community benefits and prioritization of environmental justice communities is at the heart of HB 2021. PGE engaged with Energy Advocates and other CBO leaders during the DSP community engagement process and CEP Learning Labs to identify and shape the type of projects we delineated as CBRE proxy resources in this CEP/IRP. Those engagements pointed to significant interest in smaller, distribution-connected resources that can provide tangible and visible community benefits. This is also the case for our municipalities who specify local ownership preferences under their Climate Action Plan targets. At this point, PGE does not believe that expanding CEP/IRP modeling to include potential transmission-sited CBREs is necessary to inform the Action Plan, but will

[55] LC 80 Initial Comments of Energy Advocates at 8
[56] LC 80 Initial Comments of NewSun Energy at 12

continue to dialogue with communities to see if and how transmission connected resources could meet community interests in the future.

Chapter 7. Transmission

7.1 Modeling of transmission upgrades

In related comments on the modeling of transmission upgrades in the CEP/IRP, Staff requested a clearer description of whether and how the transmission upgrades in the Action Plan are modeled in portfolio analysis and asked for a clearer description of how the proxy transmission in the Preferred Portfolio meets PGE’s needs and why it is not directly addressed within the Action Plan.[57]

PGE’s Response

Portfolio analysis in the 2023 CEP/IRP has identified the need for increased transmission capacity across multiple flowgates (primarily South of Allston, but also West of Cascades South and West of John Day). The SoA transmission upgrade from the Action Plan is modeled in portfolio analysis through the use of the SoA proxy transmission resource option. Portfolio analysis results show that alleviating transmission constraints through the inclusion of the SoA proxy resource in PGE’s portfolio reduces costs and delays the need for more costly regional transmission expansion options. The Bethel-Round Butte upgrade is one option available to PGE that can fill that transmission need be alleviating congestion. The factors discussed in Section 9.4.3 of the CEP/IRP highlight the characteristics that make the project a compelling option to pursue. Foremost among these factors is PGE’s existing right-of-way, which makes the project significantly less complex and reduces project timelines compared to greenfield development. Additionally, because of the topology of the region’s transmission system and power transfer distribution factors, alleviating congestion on a single constrained flowgate cannot be done in isolation in order to create new incremental capacity useful for energy deliveries to PGE’s service territory. To achieve the full benefits of the SoA upgrade, congestion on other constrained flowgates must be alleviated as well. Therefore, the SoA upgrade and the Bethel-Round Butte upgrade, which would alleviate congestion on the Cross Cascades South flowgate, should be considered mutually necessary.

Proxy transmission in CEP/IRP modeling meets PGE's needs in two different ways: one representing upgrades to alleviate transmission congestion; and a second representing opportunities for transmission expansion. The proxy transmission upgrade resource "SoA" represents upgrades to PGE's system that relieve transmission congestion and increase access to the existing set of PNW proxy renewable resources that are otherwise transmission constrained. Under the model, every 1 MW of SoA upgrade increases access to 1 MW of PNW resources and the energy and capacity they provide. SoA does not provide any benefits beyond those provided by the resources accessed. The transmission expansion proxy resources WY transmission and NV transmission provide access to new renewable resources and markets. Each 1

[57] LC 80 Initial Comments of Staff at 5

MW of WY or NV transmission provides 1 MW of effective capacity contribution and the energy benefits associated with 1 MW of WY wind or NV solar.

The SoA upgrade resource is addressed in the Action Plan through Action 5.A: Pursue options to alleviate congestion on the SoA flowgate, which proposes system upgrades to relieve congestion on the South of Allston flowgate and increase access to renewable resources in the PNW. The WY and NV transmission expansion projects are not addressed directly in the Action Plan because both the analysis and proxy resources themselves involve general characteristics believed to be found on the market, rather than a specific project evaluation. PGE will continue to evaluate specific transmission expansion projects.

7.2 Quantitative impact of transmission in Action Plan

Staff suggests that PGE quantitatively identify the impact of the proposed transmission upgrades in the Action Plan on PGE's ability to deliver generation to load.[58]

PGE's Response

Transmission upgrades to alleviate congestion on the South of Allston flowgate were modeled using a proxy resource that increases access to transmission-constrained PNW renewable proxy resources by up to 400 MW. Results of portfolio analysis reveal that this additional access to PNW renewables is beneficial and necessary for meeting HB 2021 decarbonization targets.

Similar to the use of proxy energy and capacity resources, proxy transmission resources do not represent specific projects; instead, they are designed to represent the array of opportunities that may become available for acquisition. PGE's Action Plan identifies two potential transmission upgrade projects to be explored that would create the transmission relief identified as beneficial and necessary in portfolio analysis. The quantification of the impact of such a transmission upgrade project on PGE's ability to deliver generation to load will be done outside of the CEP/IRP, on a project-specific basis where the full characterization of costs and benefits can be accounted for.

7.3 Drivers of transmission needs

Staff asked for clear identification of the portfolio constraints that drive transmission needs, to clarify whether they are driven by load service, renewable deliverability, or both.[59]

PGE's Response

Transmission needs are driven by both load service and renewable deliverability. PGE on-system transmission is mostly driven by load service needs. The need to expand BPA's deliverability to PGE is both a load service concern and directly impacts renewable deliverability. Regional transmission

[58] LC 80 Initial Comments of Staff at 5
[59] LC 80 Initial Comments of Staff at 6

expansion (as represented through WY and NV transmission expansion proxy selection) is driven by additional need for resource diversity to ensure that we can decarbonize reliably.

7.4 Resource options that can avoid transmission

Staff suggests that PGE update the CEP/IRP with clear identification of the resource options that are available to the model can help avoid transmission upgrades. They ask if the battery systems modeled are assumed to be on- or off-system or sited to alleviate transmission constraints during constrained periods and if the additional EE can reduce the need for transmission upgrades.[60]

PGE's Response

In the 2023 CEP/IRP storage, CBREs and DERs are all modeled as on-system resources and are not subject to transmission constraints.[61] Accordingly, all of these resources have the ability to delay the need for transmission expansion or upgrades. Storage resources provide capacity, not energy, so they cannot fully offset the need to increase transmission capacity to access additional VERs.[62] The ability of storage to provide capacity in times of need is captured in modeling through their capacity contribution, as defined by their ELCCs.

7.5 Size of SoA Upgrade

Energy Advocates ask whether the 400 MW increase in transmission capacity modeled by the SoA upgrade proxy resource represents the maximum amount possible or if additional MW could be potentially become available.[63]

PGE's Response

As modeled in portfolio analysis, a maximum of 400 MW of additional access is available through this proxy upgrade option. PGE limited this option to 400 MW as a planning assumption based on what could reasonably be forecast as potential upgrades to PGE transmission assets that flow across the South of Allston flowgate before 2030. This proxy resource represents any number of potential upgrade projects that may become available and that would alleviate current congestion on the SoA flowgate. It is possible for multiple projects to be undertaken, which could unlock more than the 400 MW. However, for planning purposes, using an amount of additional access based on reasonable forecasts, instead of best-case scenarios, increases the likelihood that the IRP's results will be consistent with actual changes to the transmission system in the future.

[60] LC 80 Initial Comments of Staff at 6
[61] Batteries and pumped hydro are also modeled as on-system resources and do not require transmission.
[62] In fact, due to losses associated with round trip efficiency, storage resources have a slightly negative capacity factor, with each storage resource added reducing the amount of energy available on the system.
[63] LC 80 Initial Comments of Energy Advocates at 9

7.6 Clarification of transmission costs

Energy Advocates ask if the costs in Table 44 of the CEP/IRP include the cost of Wyoming wind and Nevada solar. They also ask for the source of the differences in the costs of the South Allston upgrade and transmission expansion to Wyoming and Nevada.[64]

PGE's Response

The values in the CEP/IRP Table 44 do not include the costs of WY wind or NV solar, or the costs associated with market access. They are for the transmission component only. The cost of the South of Allston proxy is based on upgrade of existing lines within a right-of-way that PGE currently owns. While the costs are meant to be indicative only, the upgrades associated with SoA are likely within the existing footprint of PGE's transmission system. The costs associated with off-system transmission to access additional climate zones are indicative and based on public sources of the cost to permit and build new transmission.

7.7 Sufficiency of transmission in Action Plan

Energy Advocates state that PGE's inclusion of options in the Action Plan to pursue transmission congestion mitigation efforts on the South of Alston flowgate and invest in Bethel-Round Butte appear to be reasonable. They ask, however, if PGE is satisfied that these two transmission projects are sufficient for the foreseeable future, given the lengthy lead times necessary for new transmission.[65]

PGE's Response

Results of portfolio analysis using proxy resources provides directional findings as to PGE's need for transmission and the potential benefits of transmission expansion. Through this analysis, PGE has identified a large need for transmission and will continue to explore all potential options for relieving transmission congestion including, but not limited to, the two projects identified in the Action Plan.

7.8 Realistic transmission assumptions

Comments regarding the granularity of PGE's transmission modeling were received from Grid United and NewSun. Grid United states their support of PGE's efforts to model potential transmission proxy resources but comment that to produce a more robust analysis of regional transmission needs, PGE should include more proxy resources in analysis.[66] They also suggest that PGE should consider interregional resource diversity through interregional transmission projects.[67] NewSun commented that the CEP/IRP needs more realistic assumptions around the availability of conditional firm and long-term firm

[64] LC 80 Initial Comments of Energy Advocates at 9
[65] LC 80 Initial Comments of Energy Advocates at 11
[66] LC 80 Initial Comments of Grid United at 4
[67] LC 80 Initial Comments of Grid United at 6

transmission of confirmed and in-study BPA transmission service requests.[68] They also suggest a more detailed analysis of major BPA transmission upgrades and that PGE build those assumptions into analysis.[69]

PGE's Response

PGE agrees that more detailed analysis of transmission would better inform portfolio analysis and long-term resource selection. This includes modeling more proxy transmission resources and improving our ability to account for contraction transmission constraints.

This was PGE's first attempt to include transmission resources in portfolio modeling and with limited analytical resources available, PGE chose to rely on two proxy resources that represent any number of potential expansion transmission projects that can provide the new transmission capacity that PGE needs to decarbonize.[70] The two transmission expansion proxy resources modeled in the 2023 CEP/IRP demonstrate the benefit of resource diversity and access to new markets. Although the proxy resources are defined as transmission to WY and NV, the results associated with them shed light on transmission expansion to other locations as well. PGE hopes to improve our transmission modeling capability in the future, including through the inclusion of additional proxy resources.

This was also the first time that PGE has incorporated contractual transmission limitations into portfolio analysis, and we have been refining our approach collaboratively with our public stakeholders.[71] As a result of feedback that we received during the August 2022 roundtable, PGE changed our methodology for estimating available transmission on BPA's system. This feedback suggested that our methodology utilizing posted BPA ATC data was overestimating the available capacity by not accounting for allocations awarded since the last updates. In response, PGE developed a new method, described in the September and October 2022 roundtables, that utilized a review of BPA's 2016-2021 TSEPs to determine conditional firm and long-term firm transmission availability based on TSRs pointed at PGE's system. While the information available on ATC is imperfect, this method of estimating ATC used the best available information and made assumptions to distinguish between CF and LTF transmission capacity. Portfolio modeling is based on a simplified version of reality. There is uncertainty associated with many aspects of modeling (i.e., forecasts of costs, prices, and demand). Our transmission assumptions represent an appropriate approach to capturing the transmission-constrained reality of our planning environment and accounting for it in a manner consistent with the simplifications and uncertainty inherent in long-term planning models.

We agree that it is possible that some of the TSRs that are currently pointed at PGE's system could be redirected to other points of delivery, which would lead to an increase in PGE's need for transmission. It is also possible that TSRs pointed at other utilities could be redirected to PGE's system, lowering PGE's

[68] LC 80 Initial Comments of NewSun at 9
[69] LC 80 Initial Comments of NewSun at 11
[70] PGE also modeled one transmission upgrade resource (SoA), which is distinct from the two transmission expansion options.
[71] Transmission was discussed in PGE's April 2020, March 2021, August 2022, September 2022, October 2022, November 2022, and December 2022 IRP roundtable meetings.

need for transmission. However, there is no way to forecast this likelihood, and further, such redirects are only possible if the BPA system has sufficient ATC.

TSRs that are subject to upgrades were not included in PGE's estimation of ATC. These TSRs that are subject to upgrades are unlikely to be available until after 2030, which is beyond the Action Plan window and beyond the timeframe in which PGE's portfolio analysis was focused. Transmission upgrade opportunities that fall into this timeframe for development are not considered explicitly in CEP/IRP modeling. Rather, they are captured by the directional finding of analysis of transmission expansion, which indicate high need to expand transmission, without identifying specific projects.

7.9 Cost and availability of PGE's proxy transmission resources

NewSun commented that both the South of Allston upgrade proxy and the Wyoming and Nevada expansion proxies could benefit from additional discussion, specifically "on the basis for which PGE has determined these represent general characteristics that may be found on the market including why PGE believes they are available and how PGE estimated their costs." They also inquire as to how PGE plans to share the cost of potential SoA upgrades and how PGE is positioning itself in the market for limited transmission capacity.[72]

PGE's Response

PGE's proxy modeling for Wyoming and Nevada expansion is derived from publicly available estimates of transmission cost, and PGE does not have additional information at this time other than the estimates cited in footnote 274 of the CEP/IRP. More granular detail on availability, cost, cost allocation, and timing will be driven by specific project characteristics, and we look forward to working with Staff and Stakeholders to continue that discussion over the coming months and years. We will continue to refine and share data as it becomes available.

7.10 Proper comparison of transmission with other options

NewSun suggests that the Commission should ensure proper comparison of new transmission build costs with West of Cascades, On-System, DER, EE, Solar and Storage resources. They point to high costs and potential timeline delays commonly associated with transmission projects for justification.[73]

PGE's Response

PGE acknowledges there are sources of risk and potentially long lead-times associated with transmission expansion. This is a primary reason PGE started the process of considering these resources alongside other options in portfolio modeling in the 2023 CEP/IRP. PGE notes that we included all available cost-

[72] LC 80 Initial Comments of NewSun at 11-12
[73] LC 80 Initial Comments of NewSun at 13

effective DERs in all portfolios, including the Preferred Portfolio. PGE also notes that there are risks associated with resources that could delay the need for transmission expansion as well. For example, additional DERs can increase near-term cost impacts relative to other resources.

As highlighted in Chapter 9 of the CEP/IRP, exploring the proxy resources in this CEP/IRP does not preclude PGE from exploring other transmission or non-wires solution options. Instead, they offer insight into the potential costs and benefits of one of the numerous options that PGE will continue to monitor as options to meet energy and capacity needs going forward. Any specific transmission resources that become available in the future would be carefully evaluated using project-specific information.

7.11 Conditional Firm Transmission Approach

Renewable Northwest recommends changes to PGE's approach to modeling conditional firm transmission.[74]

PGE's Response

PGE appreciates the discussion on conditional firm transmission. As we note in Appendix J of the CEP/IRP, "PGE will continue to explore conditional firm transmission modeling options going forward." This could include power flow studies, evaluating congestion solutions (including non-wires solutions), and other approaches.

While PGE is open to discussion on how conditional firm transmission is modeled, the analytical approach suggested by RNW has significant shortcomings. PGE has concerns regarding the analytics supporting the finding that "0 hours of curtailment" should be used for modeling conditional firm transmission. Using the same analysis and logic, one could argue that since there will be no curtailment on BPA's system going forward, we should allow all resources to rely on short-term transmission products to deliver generation to load. PGE does not believe either conclusion to be appropriate. Select shortcomings of the RNW analysis are discussed below.

First, a spreadsheet analysis approach is not appropriate for studying power flows across the Western Interconnection, especially given the number of resource, load, and transmission changes coming to the West in the next couple decades. A power flow model analysis is needed to understand how system dynamics will change. Additionally, the RNW analysis does not include contingency situations. Paths generally cannot be operated at their limits due to N-1 operational constraints. The analysis also relies on one year of transmission data only (year 2022), although multiple years of data are available via the BPA website.[75] Further, the analysis does not incorporate load growth, which could result in a greater need for power and more power flowing over the pathway.

The report only examines the West-of-Cascade-South (WOCS) path and ignores the SOA path. The SOA path is a primary constraint discussed in the CEP/IRP, and whose congestion relief is outlined in the

[74] LC 80 Initial Comments of RNW at 6
[75] https://transmission.bpa.gov/Business/Operations/Paths/default.aspx

Action Plan. The SOA flow gate, and likely other pathways, must be considered when analyzing the ability for resources to provide power to PGE.

The study also makes choices PGE views as inappropriate regarding new generation that may impact the WOCS path. It only includes potential new resources from PGE, BPA, and PacifiCorp. The study does not take into account the broader anticipated changes resulting from renewable generation buildout from any other utilities, including the Washington utilities that need to build resources to meet their Clean Energy Transformation Act (CETA) obligations, or the changes resulting from new transmission lines. For instance, the Boardman to Hemingway 500kV line will deliver thousands of MWs of additional generation from Idaho and points east at Boardman, which will stress the West of Cascades South path much more severely.

The study assumes that 18% of new PacifiCorp resources will be located in the PacifiCorp West BA (PACW), and only includes 18% of new PacifiCorp resources in the analysis. This value is based on one year of historical generation data from EIA Form-930. However, Table 9.1 of PacifiCorp's 2023 IRP shows the 2030 summer peaking impact of planned resources, split out by east and west. The PacifiCorp IRP locates 31% of planned resources in PACW. Using accurate PacifiCorp numbers changes the results of this analysis. Using the default 18% assumption there are 37 curtailment hours in the analysis, but using PacifiCorp's own 31% assumption increases curtailment hours to 112 (greater than the 100 hours used in the PGE CEP/IRP). PGE believes this approach deserves closer scrutiny, specifically how a future resource assumption is formed, and also suggests that it should include resources from more than just PacifiCorp West and BPA.

PGE appreciates the interest in this methodological question and understands that more work is needed to address this question. However, given the concerns noted above, the Company does not believe the analysis provided by RNW should be used to reach any conclusion about changes to our treatment of the capacity contribution of off-system resources utilizing conditional firm transmission.

7.12 Transmission benefits of pumped hydro

In Section III of their initial comments, Swan Lake and Goldendale say that pumped storage has major benefits to the transmission needs identified in the CEP/IRP that should be considered.[76] They suggest that locating pumped hydro at strategic points on the grid can be used to address transmission congestion and that pumped hydro should be evaluated as a transmission solution in Chapter 9 and in portfolio analysis.

PGE's Response

Pumped storage was modeled as not subject to transmission constraints and building pumped hydro does not reduce the transmission capacity available to access other PNW proxy resources.[77] The benefits associated with pumped hydro's ability to relieve transmission congestion is captured through this

[76] LC 80 Initial Comments of Swan Lake and Goldendale at 6
[77] Technically, pumped hydro was modeled the same as on-system resources but given no realistic geographic opportunities in PGE's service territory for pumped hydro this choice was a simplification.

designation as an on-system resource and is consistent with the modeling of other proxy storage resources.

7.13 Additional transmission proxies

Grid United states their support of PGE's efforts to model potential transmission proxy resources but comment that to produce a more robust analysis of regional transmission needs, PGE should include more proxy resources in analysis.[78] They also suggest that PGE should consider interregional resource diversity through interregional transmission projects.[79]

PGE's Response

PGE agrees that including more proxy transmission resources would be beneficial and in the future PGE hopes to improve our transmission modeling capability, including through the inclusion of additional proxy resources. However, this was PGE's first attempt to include transmission resource in portfolio modeling and with limited analytical resources available, PGE chose to rely on two proxy resources that represent any number of potential transmission projects that can provide the new transmission capacity that PGE needs to decarbonize. The two transmission expansion proxy resources modeled in the 2023 IRP demonstrate the benefit of resource diversity and access to new markets. Although the proxy resources are defined as transmission to WY and NV, the results associated with them shed light on transmission expansion to other locations as well.

Chapter 8. Thermal Operations

8.1 Resource Utilization and Optimization

PUC Staff asked for more discussion on the shift of emissions from retail load service to wholesale sales, with Staff asking about challenges related to the "operational and/or contractual constraints."[80] Similarly, Energy Advocates asked about continual emissions reduction progress and how new clean resources reduce thermal dispatch and impact resource retirements, and how supply-side, demand-side, and other resource types are optimized and balanced in portfolio analysis.[81]

PGE's response

While PGE understands the interest in how CEP/IRP planning and analysis will translate into operational changes that lead to emission reductions, it is important to maintain the distinctions between long-term planning and system operations.

[78] LC 80 Initial Comments of Grid United at 4
[79] LC 80 Initial Comments of Grid United at 6
[80] LC 80 Initial Comments of Staff at 8.
[81] LC 80 Initial Comments of Energy Advocates at 3-4.

Actual operations depend on the actual weather, load, and market conditions, whereas the CEP/IRP forecasts depict simulated conditions based on average conditions. Accordingly, CEP/IRP projections of the use of existing resources do not constitute direction to PGE's system operations; nor have IRPs of the past constituted specific instructions to system operations. PGE's operations will continue to evolve to meet the emissions constraints of HB 2021, as well as other requirements such as the WRAP. Operations will evolve in real time based on actual weather, load, and market conditions, subject to carbon and resource adequacy requirements.

To evolve system operations and reduce emissions associated with thermal generation and purchases for Oregon retail load while maintaining system reliability, PGE must first achieve significant increases in its non-emitting generation and capacity resources. This is why it is important to understand the differences between CEP/IRP modeling and actual system operations. In this CEP/IRP, reductions in the emissions associated with serving retail load happened in two steps:

1. PGE's energy need is calculated assuming a certain reduction in emissions that is needed to satisfy emissions targets (which is achieved by reducing thermal generation/purchase for retail load)
2. Non-emitting resources are added to fill that energy need.

In actual operations these same basic steps will happen, though their order will be reversed:

1. Non-emitting resources will be added
2. Thermal generation/purchase to serve retail load will be able to decline (as non-emitting resource generation offsets the thermal output that otherwise would serve retail load).

Accordingly, there is no explicit direction from the 2023 IRP/CEP that will be used by PGE's system operators. Instead, this planning document should help direct the acquisition of a large and sufficient quantity of non-emitting generating resources, such that system operators are able to reduce thermal generation and purchases with associated emissions directed to serve retail load sufficiently to meet the emissions targets.

8.2 Colstrip operations

OPUC Staff asked for discussion on the "implications of the intermediary GHG modeling approach regarding the delivery of Colstrip generation to PGE customers."[82] Renewable Northwest asked for additional discussion and insights on why the CEP/IRP assumes offtake of power from Colstrip through 2029, particularly given that it exited the portfolio at the end of 2025 in earlier analysis.[83]

PGE's response

The intermediary GHG model reallocates GHG emitting resources while staying at prescribed annual retail load service GHG targets (based on HB 2021 targets and the CEP/IRP GHG glidepaths). To meet

[82] LC 80 Initial Comments of Staff at 8.
[83] LC 80 Initial Comments of RNW at 6.

these targets, the model can retain lower amounts of generation and emissions from resources for retail load service. This process occurs at a proportional level across all GHG-emitting resources. For example, if GHG levels must fall 20% to meet a target level, the model will shift 20% of generation and emissions from retail to wholesale at a fixed ratio across all resources.

Colstrip has a higher emissions rate than other PGE resources. For example, Colstrip's CO2e intensity is around 1.00 metric tons/MWh whereas Port Westward 1 is around 0.38 metric tons/MWh. Due to the higher emissions rate and the model setup that reduces retail generation proportionally across resources, Colstrip uses more CO2e per MWh of generation in the model. Thus, keeping Colstrip in the model reduces the amount of GHG-emitting energy that can be retained for retail sales, all other factors equal.

Table 4 compares the retail energy PGE can retain from GHG-emitting resources under the CEP/IRP Reference Case (Colstrip in the portfolio through 2029) and with Colstrip out of the portfolio starting in 2026. These data are from the intermediary GHG model.

Table 4. Colstrip's impact on CO2e related energy for retail load

	CO2e related energy (MWh)		
Year	Colstrip ref.	Colstrip 2026 exit	Difference
2023	13,186,230	13,186,230	-
2024	12,006,363	12,006,363	-
2025	11,403,928	11,403,928	-
2026	9,551,461	11,036,952	1,485,491
2027	8,063,426	9,286,410	1,222,984
2028	6,572,618	7,433,463	860,845
2029	5,076,307	5,724,966	648,659
2030	4,029,389	4,029,389	-
2031	3,631,008	3,631,008	-

However, since the Action Plan targets a percentage of 2030 energy need for the year 2028 target, and since Colstrip is out of all CEP/IRP portfolios by 2030, Colstrip exiting the portfolio sooner does not impact the Action Plan. For example, in the Action Plan we target 543 MWa of clean energy by 2028. 543 MWa represent 60% of the 2030 need of 905 MWa. As a result, an earlier exit of Colstrip would not impact the Action Plan's energy target as currently constructed. Colstrip leaving the portfolio sooner could impact Action Plan capacity need values. More data and discussion on the impact of Colstrip exiting the portfolio earlier than assumed in the CEP/IRP is in Section 6.10.5.

RNW asked for additional information regarding why Colstrip is included in the resource portfolios through 2029, especially given that it exited the portfolio at the end of 2025 in earlier analysis.

For CEP/IRP planning purposes, the exit year was moved from the end of 2025 to the end of 2029 due to uncertainty in achieving a 2025 exit and higher certainty of a 2029 exit provided by SB 1547 requirements. PGE owns a minority 20% share in Colstrip Units 3 & 4 and cannot act unilaterally on operational decisions or the exit/closure of either Colstrip unit. Recent transactions entered by other Pacific Northwest owners to exit Colstrip Units 3 & 4 at the end of 2025 benefited from state policy prohibiting the delivery of coal power to serve retail load after 2025. As PGE continues discussions with the Colstrip owners in exploring an exit, potential buyers have different motivations than PGE. Potential buyers lack sufficient retail load for PGE's portion of Colstrip Units 3 & 4 and have no transmission rights to move the power from Colstrip and intends to maintain its long-term transmission rights from Colstrip to provide greater access to climate zones providing high-capacity factor wind resources. Additionally, there remains significant regulatory uncertainty that could materially impact future operations of Colstrip.[84] Due to the ongoing nature of the discussions, we will keep our stakeholders informed of details as they emerge.

Chapter 9. Emissions

9.1 Intermediary GHG model detail

Oregon PUC Staff asked for additional discussion on the intermediary GHG model specific to the assumptions and logic behind the retail load service and wholesale sales generation and emissions allocation. [85]

PGE's response

PGE appreciates the opportunity to provide additional detail on the intermediary GHG model beyond what is in Chapter 5.3 and Appendix H.2 of the CEP/IRP. The intermediary GHG model's primary output is the amount of energy that can be retained for retail load from CO2e emitting resources on an annual timestep which is used in portfolio analysis. This information is then used in portfolio analysis.

The intermediary GHG model relies on three primary data sources: existing thermal generation data, historical generation data, and DEQ emissions data. Generation data are used as input data for PGE-owned thermal generation. These data come from 39 different price futures and set the economic dispatch level for PGE thermal generation in the model. Historical data help determine the level of annual GHG emitting power purchases, for both specified and market unspecified sources. They also determine, at the

[84] The first EPA proposal seeks to address Mercury and Air Toxics Standards (MATS) and could require investment in excess of $600 million to retrofit Colstrip controls, likely resulting in the shutdown of both Colstrip units as soon as 2027.
[85] LC 80 Initial Comments of Staff at 8.

fuel type level (coal and gas), the ratio at which resources are retained for retail load service versus sold into the wholesale market. DEQ emissions data are used to calculate GHG emissions from each resource.

In each CEP/IRP forecast year, the model performs these steps:

1. Calculate how much CO2e is generated for retail load service in the absence of a retail load carbon target. For example, if a resource generates 100 MWh of power at a CO2e intensity of 0.5 metric tons/MWh, and 80% of the resource is retained for retail load, 80 MWh (80% of 100) would be multiplied by 0.5 (the intensity rate) to arrive to 40 metric tons of CO2e. This tonnage value is summed together with all other resources to arrive at a system total.
2. Compare that total calculated in step 1 to the year's CO2e target:

    If over the target: the model reduces generation at all facilities by the same factor to meet the target. For example, if the target is 1,000 metric tons of CO2e, and the aggregate dispatch has 2,000 metric tons, the dispatch of all resources for retail load service is reduced by 50%. Resources are reduced in the same proportion regardless of CO2e intensity. The remaining energy (the difference between economic dispatch and retail load service) is assumed to be sold on the wholesale market. This occurs in most years / price futures.

    If under the CO2e target: the model increases the amount of market unspecified purchases until the CO2e target is met. This upward adjustment occurs seldomly outside of the first few years in the model. Total market unspecified purchases can also move downward as the CO2e targets tighten. This is different than other resources that are assumed to operate at their economic dispatch or historical average levels throughout the planning horizon. In all cases the difference in total generation versus generation retained for retail load is assumed to be sold on the wholesale market.

The resulting output from these steps are 39 annual estimates (from the 39 price futures), by resource, of how much energy and emissions are retained for retail load service and sold into the wholesale market. The intermediary GHG model does not alter the economic dispatch values or historical generation averages, with the exception of unspecified market purchases (as discussed in step 3 above).

The intermediary GHG model also passes some financial information to the Portfolio Analysis and price impact models. Specifically, it informs the Portfolio Analysis model of the annual value of the total generation from PGE owned resources. This is done by multiplying the MWh of generation by the annual average market price. Other financial parameters associated with PGE owned resources (like fixed costs) flow into the Portfolio Analysis model via other avenues. The intermediary GHG model informs the price impact model of net benefit of wholesale transactions, again using annual average price and generation data.

9.2 CEP/IRP GHG analysis

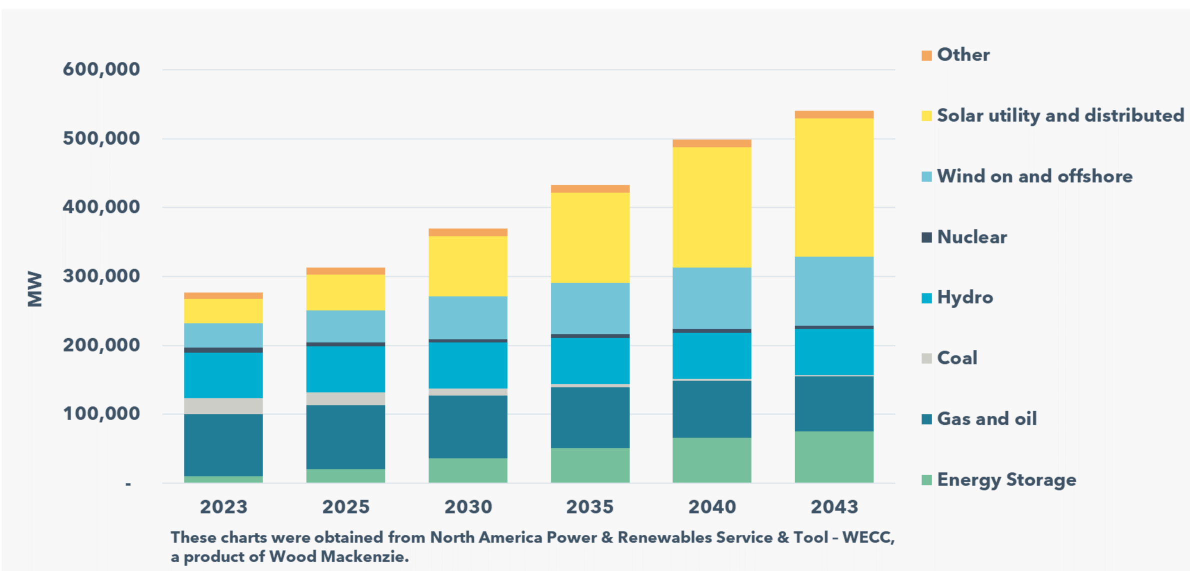
RNW asked if PGE could perform additional Portfolio Analysis specific to GHG glidepaths that take the social-cost-of-carbon and the time-value of GHG emissions into consideration, including modifying the discount rate to one that "reflects the time-value of GHG emissions" and reductions. They also inquired about additional analysis on how changes to resources, policy, and markets across the Western Interconnection would impact PGE's thermal fleet dispatch in CEP/IRP modeling.[86]

PGE's response

The CEP/IRP analyzes 39 prices futures/thermal operations possibilities that include varying levels of carbon pricing in conjunction with five GHG glidepaths. While the SCC is excluded from the Preferred Portfolio analysis, it is included in the risk portion of Portfolio Analysis, which examined various prices futures and thermal dispatch variations, some of which included the social cost of carbon. These price futures and glidepaths were studied in Portfolio Analysis leading to the conclusion that a linear GHG glidepath best balances the costs and multiple sources of risk with the rate of emissions reductions to meet HB 2021 targets by 2030. As a result, PGE believes that the current CEP/IRP analysis is robust, and does not believe that the RNW suggested additional analysis would help determine the construction of the CEP/IRP's Preferred Portfolio and/or the optimal GHG glidepath. PGE also believes that changing the discount rate applied in portfolio analysis would not yield useful insights. the discount rate used in IRP modeling is a function of PGE's weighted average cost of capital and it would be inappropriate to change these financial parameters to values that do not represent the reality of the economic costs that PGE faces when considering resource procurement decisions.

Regarding how PGE thermal resource dispatch would change due to changes in the resource mix and policies in the Western Interconnection, the CEP/IRP uses a Western Interconnection buildout, sourced from Wood-Mackenzie, that adds hundreds of thousands of MW of wind, solar, and storage resources to the West, while also retiring thermal generation, throughout the IRP planning horizon. This is shown in **Figure 3** (which is the same as Figure 20 in the CEP/IRP).

Figure 3. WECC capacity installed by year and generation source



[86] LC 80 Initial Comments of RNW at 3-6.

Within this renewable-heavy West PGE forecasts the dispatch of thermal resources against 39 different price futures that include a range of gas, hydro, carbon price, and operational variables. The carbon prices tested include an EPA social cost of carbon price with a 2.5% discount rate. These price futures feed into Portfolio Analysis. As a result, the CEP/IRP already tests a wide range of operational futures for thermal resources in a renewable heavy landscape, enabling a robust portfolio analysis process in the 2023 CEP/IRP.

9.3 Retail and Wholesale Emissions

Energy Advocates asked for more transparency regarding thermal facility operations and asked OPUC to take wholesale emissions into account when evaluating the CEP/IRP and when considering if PGE's participation in organized markets is in the public's interest.[87]

PGE's response

PGE understands the OPUC's interest in the generation (and emissions) from existing thermal facilities for wholesale sales. To inform such consideration, PGE has been fully transparent in both the development and filing of the CEP/IRP in providing data on thermal operation forecasts. PGE has provided examples and data showing the retail/wholesale allocation in the IRP and via the Clean Energy Plan Data Template. For example, The Clean Energy Plan Data Template shows the difference between retail and wholesale emissions by portfolio, and an emissions breakout by fuel type for the preferred portfolio at the retail and total (including wholesale) level.

As explained in the CEP/IRP, access to wider geographic and technological diversity of resources is essential to reducing emissions while maintaining affordability and reliability for our customers. Participation in organized energy markets is core to this strategy. PGE's participation in the Energy Imbalance Market (EIM) has already saved our customers money. As the region looks to expand organized markets, PGE will remain active in those conversations to ensure that market design and opportunities for participation align with our customers' interests and our emissions targets.

9.4 Market unspecified purchase emissions rate

Energy Advocates asked about the market unspecified CO2e intensity rate (0.428 metric tons/MWh) assigned to all market unspecified emissions in the CEP/IRP, and questioned if the CEP/IRP should be revised to note that some market unspecified purchases made outside the EIM could have a higher emissions rate (the CEP/IRP currently notes that some market unspecified purchases could have a lower rate).[88]

[87] LC 80 Initial Comments of Energy Advocates at 4.
[88] LC 80 Initial Comments of Energy Advocates at 5.

PGE's response

While PGE agrees that some market unspecified purchases may have a CO2e intensity rate above 0.428 tons/MWh, PGE does not find this revision necessary to include in the CEP/IRP. For clarity, the 0.428 metric tons per MWh rate assigned to market unspecified purchases is prescribed by OAR 340-215-0120.

9.5 Factors that impact annual GHG variations

Specific to the C-Level analysis, Energy Advocates asked what other factors can influence annual GHG emissions levels (beyond hydro and temperature variations). They request that PGE consider models that can forecast the impact of any additional factors on PGE's emissions. Additionally, they advise that PGE's risk-based CEP/IRP analysis should evaluate strategies that can mitigate emissions impacts from these influencing factors.[89]

PGE's response

As discussed in Chapter 5 of the CEP/IRP, other factors that impact GHG emissions beyond hydro and temperature variations include, but are not limited to, economic factors and wind/solar conditions. For example, an economic recession could unexpectedly reduce load and thus CO2e emissions. Or an unexpected increase in large customer loads resulting from sector-specific growth could increase load and CO2e emissions. These GHG variations are due to unexpected load changes likely being initially met with changes to thermal dispatch and/or emitting resource purchases in wholesale markets. In the event of sustained lower loads, PGE could acquire fewer new clean resources than in the Preferred Portfolio and still meet HB 2021 targets. In the event of sustained higher loads, more clean resources would be needed to meet HB 2021 targets.

Portfolio analysis takes economic factors into account by incorporating different load trajectories via the High and Low Need Futures. In the High Need Future (more load) more clean resources are built to meet the HB 2021 CO2e targets. In the Low Need Future (less load) fewer resources are required to meet CO2e targets. These High/Low Need Futures feed into the risk metrics used for portfolio analysis. As a result, some of the economic risk associated with GHG emission reductions is already accounted for in portfolio analysis.

PGE did not specifically model wind/solar variations in the CEP/IRP, although some wind correlations are likely picked up through the temperature analysis that is part of the C-Level study (wind generation is often correlated with temperature).

[89] LC 80 Initial Comments of Energy Advocates at 5.

9.6 GHG impacts and resource diversity

Related to GHG emission variations, Energy Advocates asked if acquiring resources from outside the Northwest could help reduce emissions via resource diversity and also reduce dependance on regional hydropower.[90]

PGE's response

Portfolio analysis demonstrates diversity benefits from procuring resources from a wider geographic footprint. Diversity in generation can lower the total amount of resources required to meet needs, potentially lowering system costs. This is explored in the CEP/IRP via options to build solar in the desert Southwest and build wind in Wyoming. Additionally, the CEP/IRP notes in Chapter 8.5, specific for getting from year 2030 to 2040, "the need for alternative resources and/or expanded transmission networks, from a geographic and/or technological perspective, to achieve longer-term GHG emission reductions while maintaining reliability."[91]

Regarding emissions, PGE plans to comply with HB 2021 GHG-emission targets using a linear emissions-reduction glidepath and procurement of non-emitting resources predicated upon the need to meet targets based on average conditions. Procuring resources from outside of the region will not impact these GHG targets. In portfolio analysis, non-emitting resources are used to fill the energy need in PGE's portfolio. The CEP/IRP does not plan to replace existing non-emitting generation, including owned and contracted regional hydroelectric projects. As a result, while there are benefits from acquiring geographically diverse resources, they do not help reduce the usage of regional hydroelectric power in the CEP/IRP, nor do they reduce GHG emissions or variability inside the IRP modeling process.

Chapter 10. Modeling details

10.1 Regional Adequacy Programs

On the topic of the regional resource adequacy through the WRAP program, Staff asks PGE for "analysis or discussion… (on) how the current Action Plan might impact their position in the WRAP… engagement in ongoing design elements, and/or how the… WRAP could influence the Action Plan."[92]

PGE's response

As we look toward binding WRAP participation, it will be necessary to consider how the IRP and WRAP may need further alignment to identify and manage potential future conflicts. PGE will continue to explore how the WRAP and IRP interact and may use WRAP data to guide IRP and other planning choices at a future date. Key IRP assumptions (reliability targets, resource capacity accreditation,

[90] LC 80 Initial Comments of Energy Advocates at 4.
[91] PGE CEP/IRP at 195
[92] LC 80 Initial Comments of Staff at 9

transmission assumptions, load forecasting) that could be impacted by participation in the WRAP are discussed in IRP Chapter 3.2.1.

Specific to the Action Plan, it is designed to meet capacity needs based on the IRP adequacy model (Sequoia) which does not currently take WRAP targets into consideration. Resources acquired by PGE via the Action Plan will impact PGE's WRAP forward showing, but those resources will be evaluated using different (the WRAP's) methodologies, footprints, and timeframes, leading to different effective load carrying capabilities (ELCCs) compared to the IRP.

10.2 Post-2030 price impacts

On the topic of price impacts post 2030, Staff asks for more details on the price impact of the Preferred Portfolio post 2030.[93]

PGE's response

There is significant uncertainty in the potential resource actions post 2030 given the inability of existing resource options and current transmission capacity to meet the estimated system needs, as described in Section 8.5, Post-2030 resource options and Section 11.5.3, Resource buildout robustness analysis, within the IRP.[94,95]

Considering this uncertainty, PGE leveraged the concept of expensive generic resources to meet a portion of the system needs beyond 2030.[96] These generic resources could be a new resource that is currently commercially unavailable, like hydrogen, advanced nuclear or advanced geothermal, or an existing resource that becomes more cost-competitive over time, like longer-duration storage.

The shape of price impacts of the Preferred Portfolio post-2030 is primarily driven by the addition of these expensive generic resources (generic capacity and generic variable energy resources (VERs)). The generics are designed to be expensive to ensure they do not impact other resource selection and are chosen after all other options are exhausted. The outputs of the annual price impact model (ART) are highly sensitive to the cost assumptions of generic resources costs and thus show a steep increase in total costs after 2030. The factors that impact the post 2030 costs and benefits within the price impact calculation are detailed below:

> **Fixed costs** – The increase in fixed cost is driven almost exclusively by the addition of new resources, which include the addition of over 6000 MW of generic resources in the post 2030 timeframe in the preferred portfolio. Other resource additions such as transmission also contribute to the increase in fixed costs, but the relative impact of the generic resources is higher because they are larger in quantity.

[93] LC 80 Initial Comments of Staff at 9

[94] Post-2030 resource options is available on page 194, https://edocs.puc.state.or.us/efdocs/HAA/lc80haa8431.pdf#page=215

[95] Resource buildout robustness analysis is available on Page 294, https://edocs.puc.state.or.us/efdocs/HAA/lc80haa8431.pdf#page=315

[96] The generic resource concept was also used in the 2019 IRP to fill long-term capacity need

Variable costs – New non-emitting resources have little to no variable costs. The variable costs of existing resources are expected to trend lower. Compared to the variable costs in 2030, the variable costs in 2043 are 43% lower.

Market benefits – Wholesale market sales net of purchases are expected to stay relatively constant, between 9%-11% of the total system cost in 2030. These reflect the aggregate impact of lower electricity prices and increased wholesales.

For additional details, Figure 134 in Appendix H.6 of PGE's CEP/IRP includes a high-level discussion on the key drivers of costs and benefits in the calculation of annual prices.

10.3 Qualifying Facilities (QF) sensitivity

Staff asks PGE for an explanation of why the High QF case has a much lower impact on energy needs compared to the Low QF scenario. Specifically, the high QF case only raises energy need by 1 MWa whereas the low case decreases energy need by 36 MWa.[97]

PGE's response

The difference in the energy impact between the high and low QF cases is due to the high and low case QF assumptions relying on QF success rates by schedule, rather than symmetrical up/down of nameplate MW values. The net nameplate MW difference between the high and Reference Case is 5.8 MW, whereas the difference between the low and Reference Case is 138 MW. This difference in nameplate capacity between the low/ref/high cases leads to a larger energy (and capacity) difference between the reference and low cases as compared to the reference and high cases.

The Reference Case QF assumptions in the 2023 IRP include 100% of online contracts, 50% of Schedule 201 executed but not online contracts, and 100% of Schedule 202 executed but not online contracts (Schedule 201 projects are 10 MW or fewer, Schedule 202 projects are greater than 10 MW). The Reference Case assumption is noted and discussed in UM 1728 Order 22-259, Appendix A, page 5.

The high and low case QF assumptions used in the 2023 CEP/IRP are based on the modeling from UM 1728.[98] The high case assumption is for 100% of online QFs and 100% of contracted projects. Setting the maximum at 100% is appropriate given the lack of QFs in the queue at the time of assumption finalization, which signaled a low likelihood of having any projects beyond the full contracted amount in 2026. Due to the lack of projects in the queue, and a desire to keep consistency across assumptions, this assumption is used for 2030 as well. The low case assumption is 100% of online QFs and 50% of contracted QFs. 50% is used since it matches the total PGE QF success rate. Aggregated PGE believes these are appropriate inputs to the QF sensitivity and produce useful results to understand the possible future trajectories of QF incorporation on PGE's system.

[97] LC 80 Initial Comments of Staff at 10

[98] PGE presented this modeling at the March 2022 IRP roundtable meeting. That presentation can be found here: https://edocs.puc.state.or.us/efdocs/HAH/um1728hah152948.pdf

10.4 Resource adequacy load modeling

Energy Advocates express agreement with PGE's use of 30 years of temperature data in resource adequacy modeling (as opposed to a longer period of 42 years). They request additional information on PGE's consideration of methods to extrapolate temperature data reflective of future climate impacts.[99]

PGE's response

The hourly 42- and 30-year historical load estimate data used in the IRP are for Sequoia, the resource adequacy model. The data are used to reshape the monthly econometric load forecast into an hourly forecast (as Sequoia requires hourly data). The monthly econometric load forecast uses a trend for its heating degree day and cooling degree day inputs to capture the warming temperatures experienced by Portland (effectively a proxy for global warming). Although the hourly shaping file is not extrapolated into the future, the warming trend is embedded in the forecast via the monthly econometric load forecast. More information on the warming trend used in the load forecast, and a comparison of the trend to four different climate models, is in Appendix D.4 (see page 485). PGE is exploring how to change the hourly shaping forecast to better account for climate change for future planning work.

10.5 Accessibility of the IRP quantitative findings

In the context of Action Plan targets provided in the CEP/IRP, Energy Advocates encouraged PGE to consider how to make quantitative information more accessible to non-technical audiences. They offer a specific suggestion for PGE to consider comparing forecast amounts to existing projects to provide a sense of scale, offering PGE's Wheatridge facility as a specific example.[100]

PGE's response

It is challenging to provide examples of existing projects to compare to the resources selected in portfolio analysis. This is largely due to new resources have different generating characteristics than existing resources. For example, the Wheatridge project consists of 300 MW nameplate of wind, 50 MW nameplate of solar, and 30 MW nameplate of 4hr battery. 1,334 MW is roughly equivalent to four Wheatridge facilities in nameplate size, depending on which components you are including (wind, solar, battery). However, the 1,334 MW of wind in the IRP Preferred Portfolio includes projects with newer technology and in different locations (like Wyoming) that will provide different amounts of energy and effective capacity per nameplate MW of resource than the wind associated with the Wheatridge facility. While accessibility is a goal of the CEP/IRP, we want to achieve that goal in a way that minimizes the potential for confusion or misunderstanding of the characteristics of the resources selected.

[99] LC 80 Opening of Energy Advocates at 6
[100] LC 80 Opening of Energy Advocates at 14

Chapter 11. Portfolio analysis

11.1 Portfolio with Colstrip exit in 2025

Staff suggests that PGE update the CEP/IRP to include a portfolio showing a 2025 exit of Colstrip from PGE's portfolio for comparison to portfolios with a Colstrip exit in 2029.[101]

PGE's Response

As noted above in **Section 8.2**, for IRP planning purposes, PGE will continue to offtake power from Colstrip 3 & 4 through 2029. If there is sufficient interest from stakeholders, PGE would consider analyzing an informational portfolio in which Colstrip exits the portfolio in 2025, but the portfolio would not be considered actionable by PGE due to the reasons listed above.

11.2 ETO coordination and EE cost-effectiveness

Energy Advocates asked if PGE has more current cost-effectiveness data from Energy Trust for use in this CEP/IRP.[102]

PGE's Response

PGE does not have a more current forecast of cost-effective EE from Energy Trust. Given the circular interaction between portfolio analysis and cost-effectiveness, there will almost always be a gap between the two planning approaches. Fundamentally, cost-effectiveness is a simplified method used to mimic the portfolio analysis conducted within an IRP to evaluate resources decisions outside the IRP process. To perform cost-effectiveness analysis, PGE develops and provides Energy Trust with avoided costs through UM 1893. These avoided costs are a translation of the Preferred Portfolio and other portfolio analysis inputs developed through the IRP. Thus, given this relationship between portfolio analysis and cost-effectiveness, Energy Trust projections would always be stale when included in a new IRP as shown in **Figure 2** of these comments (see **Section 4.3**). Additionally, because cost-effectiveness is a simplified translation of portfolio analysis, the results from portfolio analysis are the most accurate representation of resource decisions.

PGE has traditionally depended on Energy Trust to determine the cost-effectiveness of EE because it is impractical to perform the IRP portfolio analysis for every single energy efficiency measure. Additionally, performing cost-effectiveness tests give Energy Trust the strategic flexibility at the program and measure level needed to procure energy efficiency. This process has been accepted traditionally because the year-on-year changes to avoided costs have not been as significant, and changes in cost-effective energy efficiency would be included in the next IRP and not require a shift in the most recent Action Plan.

[101] LC 80 Initial Comments of Staff at 9
[102] LC 80 Initial Comments of Energy Advocates at 11

However, with the introduction of HB 2021 and the forecasted constraints on transmission, the CEP/IRP also evaluates the remaining technical achievable potential (noted as additional, or non-cost-effective, energy efficiency) as a resource option within portfolio analysis, leading to the finding that energy efficiency would reduce long-term cost and risk.

11.3 Company-wide emissions and emissions from market sales

NewSun recommended that PGE run additional portfolios with changes to assumptions about GHG emissions. Specifically, they recommended one portfolio defined by the assumption that PGE's emissions associated with market sales are 25% lower, and another portfolio that assumes zero emissions company-wide by 2040.[103]

PGE's Response

The need to build new resources in portfolio analysis is driven by GHG-reduction targets associated with serving retail load. A change in emissions associated with market sales would therefore not impact portfolio analysis or change the resource buildout of the Preferred Portfolio or the Action Plan that was built upon it. This is similarly true of company-wide emissions. Given the large number of topics of interest in the docket, PGE does not think it is appropriate to devote time to such an analysis that would not impact the Action Plan.

11.4 Unconstrained CBREs

In related comments regarding the resources made available for selection in portfolio analysis, NewSun recommended that PGE run a portfolio with unconstrained CBRE potential, one with all available distributed solar defined by the achievable potential, unconstrained by cost-effectiveness, and one with EE and DR available up to achievable potential, unconstrained by cost-effectiveness.[104]

PGE's Response

The 155 MW of available CBREs is based on PGE's assessment of the resource potential and is the maximum amount that PGE considers to be realistic and informative in portfolio analysis. The 155 MW of available CBREs is additional to the cost-effective DERs forecasted in the DSP that PGE included in the Preferred Portfolio.[105]

Forecasts of distributed solar used in portfolio modeling are based on forecasts from the DSP Part 2. The 'cost-effective' reference on page 109 of the CEP/IRP is in reference to EE and DR only. We state in the

[103] LC 80 Initial Comments of NewSun at 7
[104] LC 80 Initial Comments of NewSun at 7 & 9
[105] For clarification, in their comments NewSun incorrectly suggests that the Optimize CBRE portfolio allows the model to select CBRE's without consideration of the 10% rCBI benefit. The Optimized portfolio selected 100% of available CBREs with the 10% rCBI benefit included.

CEP/IRP that distributed solar PV is driven by customer adoption factors, which include costs as a primary driver. PGE is not modeling rooftop solar PV on a basis of cost-effectiveness, and therefore we cannot model a portfolio unconstrained by cost-effectiveness. As noted above in Section 3.1, PGE is planning a modeling refresh with new DER estimates, however it is not clear that the net effect of this update across all DERs, including electrification effects, would lead to any significant difference in resource need.

PGE already analyzed and included portfolios that allowed access to additional EE and DR that was non-cost-effective. As depicted in CEP/IRP Figure 32, the cost-effective potential and non-cost-effective potential together comprise the 'achievable potential' cited by NewSun. Therefore, running additional portfolio analysis on EE and DR 'unconstrained by cost-effectiveness' would not provide any new and meaningful insights.

11.5 Post-2030 resource plan

RNW commented that PGE's post-2030 plan is unclear and suggested a more comprehensive, centralized discussion of the various post-2030 elements, including needs, resources, transmission, and emerging technologies.[106]

PGE's Response

PGE appreciates that RNW agrees that "getting to 2040's 100% emissions-reduction target… (is) not merely a "more of the same" proposition for adding resources." We are aware of the long-lead time challenges associated with many of the emerging technology resources that are discussed in Chapter 8.5 of the CEP/IRP. The CEP/IRP provides energy and capacity need values beyond 2030, as well as generic variable energy resource and capacity resources to create a general resource pathway. We will continue to monitor, and when appropriate, evaluate specific new resource options as they develop in future planning work.

As discussed in Chapter 8.5 of the IRP, achieving the 2040 emissions reduction target will likely require resources not commercially available today. This is due a large need for energy and capacity resources, a lack of transmission for resources, and uncertainty around costs and characteristics associated with emerging resources. The capacity challenge is particularly daunting. In Chapter 8.5 (and discussed in the June 2022 roundtable meeting) PGE tested a year 2040 portfolio with 6,000 MW of Northwest wind, 6,000 MW of Northwest solar, and 6,000 MW of storage. Even with these resource additions, there were time periods where energy stored in the batteries is exhausted and there was not enough wind and solar generation to recharge the storage and/or meet load. This suggests that even a massive resource addition of current technologies will be insufficient to maintain system reliability.

The CEP/IRP discusses emerging resources, like hydrogen, nuclear, costal technologies and more, in Chapter 8.5. One challenge with using emerging resource in power planning is sensitivity to cost uncertainties. If the CEP/IRP assumes an emerging resource is inexpensive, it may be picked by the model, while if costs are assumed to be high, it likely will not. As a result, testing emerging resources

[106] LC 80 Initial Comments of RNW at 9

with large cost uncertainties often does not reveal which resource is the best fit for the power system. Due to these uncertainties, a more prescriptive analysis past year 2030 would be speculative at best. At worst it could be misleading and send incorrect signals to policy makers and the market.

11.6 Hybrid resources

RNW commented that transmission assumptions in the calculation of ELCCs are likely discounting the value of hybrid resources relative to standalone renewables.[107]

PGE's Response

PGE disagrees that transmission assumptions made in the calculation of ELCCs unfairly discount the value of hybrids relative to stand-alone renewables. The same methodological assumptions regarding how long-term firm and conditional firm transmission are used for standalone renewable and hybrids. Currently there are no cross-resource ELCC decline impacts in PGE's portfolio optimization model, so selection of renewables before hybrids would not depress hybrid ELCC values.[108] PGE has significant concerns with the analytics used to support this comment, which are addressed in these comments in **Section 7.11, Conditional Firm Transmission Approach**.

However, while investigating the modeling assumptions of hybrid proxy resources, PGE discovered an error in the capacity factors of hybrid resources used in portfolio analysis. While not affecting the capacity contribution of the resource, the result was an inappropriate increase in the per MWh cost of the resource. The error occurred in the querying of outputs from economic dispatch simulation to be used in portfolio modeling and only affected hybrid resources. The error resulted in capacity factors that were 33% to 40% of what they should have been (**Table 5**). As a result, the potential energy benefits of hybrid resources were underestimated in modeling.

Table 5. Average annual capacity factors of hybrid proxy resources

	Corrected	With Error
CV_Hyb_1	28.6%	9.5%
CV_Hyb_2	29.2%	11.7%
MCMN_Hyb_1	22.3%	7.4%
MCMN_Hyb_2	23.0%	9.2%

[107] LC 80 Initial Comments of RNW at 8
[108] An example of a cross-resource ELCC decline is the addition of 100 MW Gorge wind reducing the ELCC of the next 100 MW of SE Washington wind.

PGE plans to correct this hybrid capacity factor error in portfolio analysis in conjunction with the DER forecast refresh mentioned above in **Section 3.1**. These results are planned to be presented within the LC 80 docket.

11.7 Reliance on batteries

Swan Lake and Goldendale commented that the IRP relies too heavily on batteries.[109]

PGE's Response

PGE disagrees with this comment. Much of this comment centers around potential "commodity volatility and supply chain disruption(s)" and the "feasibility of constructing 20 GW of battery storage in the next ten to twenty years (on the regional level)." In the PGE IRP, the total amount of battery added by 2030 is 632 MW.[110] In late April 2023 PGE announced a total of 400 MW of 4hr battery procurement via the 2021 RFP and recently PGE announced another 75 MW of battery storage acquisition.[111] Based on this experience, and the amount of remaining projected battery to be acquired by 2030 (157 MW), PGE believes its projected IRP battery procurement level is reasonable.

Additionally, while PGE appreciates the need for resource diversity, the CEP/IRP Action Plan does not rely on batteries alone for meeting capacity needs. Wind, solar, transmission proxies, demand side resources, and other resources also provide capacity to the CEP/IRP through a portfolio approach.

Lastly, the CEP/IRP does not construct resources; it identifies need, discusses resource pathways, and provides tools for future all-source RFPs to acquire resources. Depending on resource prices and changing resource needs, future RFPs may not select additional battery storge for PGE, and instead rely on other resources to maintain resource adequacy. Future RFPs may also select more battery storage than identified in the IRP, again depending on resource need, prices, and other factors.

11.8 Modeling inputs

CUB highlighted the vintage issue between the DSP and the IRP, noting the need to update modeling inputs to reflect policies that passed after the publication of the DSP.[112]

PGE's Response

PGE agrees with CUB that vintage issues exist within IRPs, especially given the number of policy developments in 2022 following the publication of the DSP that thus are not fully incorporated in all aspects of the CEP/IRP. As mentioned in **Sections 3.1** and **11.6** of this document, PGE is planning on

[109] LC 80 Initial Comments of Swan Lake and Goldendale at 10
[110] This includes 232 MW of battery added in the Preferred Portfolio through capacity expansion modeling and is 400 MW of battery PGE is acquiring from the 2021 RFP.
[111] https://portlandgeneral.com/news/pge-closes-out-2021-rfp-with-procurement-of-75-mw-battery-storage-project
[112] LC 80 Initial Comments of CUB at 1 f

refreshing portfolio analysis with an updated DER forecast that incorporates the impact of these tax credits.

Chapter 12. RFP

12.1 Acknowledgement of accelerated procurement

Staff requested clarification on whether PGE is seeking acknowledgement of any aspect of the accelerated procurement approach beyond the 2023 All Source RFP in this CEP/IRP.[113]

PGE's Response

Yes, PGE is seeking acknowledgement of procurement actions beyond the 2023 RFP. The Action Plan in the CEP/IRP identifies needed resource procurement through the end of 2027. Meeting the Action Plan items through 2027 will likely require multiple RFPs in that timeframe to acquire sufficient resources to maintain reliability and meet HB 2021 emission reduction targets.

12.2 CEP/IRP-RFP Topic Expectations

Staff requested more information about which topics the Company expects to be relevant to both the CEP/IRP and the 2023 All-Source RFP.[114]

PGE's Response

While PGE does not know for certain which topics will be of interest in both the CEP/IRP and RFP dockets, the Company notes that historically RFPs have been routinely updated from new IRP estimates.[115] PGE anticipates continuing this in the current RFP by updating RFP procurement targets with the best information available.

RFPs generally attempt to rely on IRP methods to value bids.[116] PGE expects that there could be methodological questions about how bids will be evaluated in the 2023 All-Source RFP. A potential example of this is the question of the capacity contribution effect of conditional-firm transmission being discussed in **Section 7.11, Conditional Firm Transmission Approach**. Determining the appropriate treatment would affect both proxy resource modeling in the CEP/IRP as well as RFP bid evaluation. While PGE ca not *ex-ante* describe which methodological questions will be discussed, the Company can work with stakeholders to identify which methodological topics would affect both the CEP/IRP and RFP dockets.

[113] LC 80 Initial Comments of Staff at 3
[114] LC 80 Initial Comments of Staff at 2
[115] PGE updated its forecasted needs multiple times in the 2021 All-Source RFP (see UM 2166 for examples)
[116] The 2021 All-Source RFP utilized the IRP models Sequoia, ROSE-E, and Aurora to evaluate bids. There have been counterexamples from earlier RFPs, such as the 2018 RFP that utilized a stand-alone program to evaluate bid portfolios.

12.3 2023 RFP approach

Staff requests additional clarity about how PGE's approach to the proposed 2023 RFP may differ from the strategy for ongoing procurements subsequent to the 2023 RFP.[117]

PGE's Response

As noted in our May 19, 2023 Draft RFP filing, PGE expects that the 2023 All-Source RFP will serve as an opportunity for PGE to drive reliability and affordability by seeking the remaining projects able to deliver to PGE across BPA's system using long-term service without costly upgrades.[118] Table 43 of the CEP/IRP notes that there is only approximately 1800 MW of BPA transmission deliverable to PGE in advance of upgrades. Once the current volume of transmission is exhausted, PGE's future procurements will likely include enabling actions – such as alleviation of transmission congestion or additional rights – that will allow resources to be delivered to customers. PGE anticipates identifying these enabling actions through a Request for Information (RFI) later this year, and we will use responses to that RFI to identify which enabling actions may best position PGE for future acquisition of generating resources.

12.4 CBRE influence on RFPs

Staff requests an explanation of how RFPs for non-emitting energy will be adjusted in response to CBRE acquisition and how the two RFPs will be timed.[119]

PGE's Response

PGE anticipates that both the 2023 All-Source RFP and the community-centric process to acquire CBRE resources will align with the 2023 CEP/IRP Action Plan, once an acknowledgment decision has been made. PGE's resource plan identifies a target of 66 MW of CBRE resources to be online by 2026, and PGE anticipates working directly with communities to identify resources that should be prioritized and potentially acquired. Should CBRE volume in the Action Plan change leading up to or during CEP/IRP acknowledgment, PGE and communities will adjust the volume of resources accordingly to align with the acknowledged Action Plan. The 2023 All-Source RFP is ongoing and is scheduled to have a final shortlist to present for regulatory acknowledgment following the acknowledgment of the CEP/IRP, and PGE similarly anticipates building the final shortlist volume in a way that complies with the acknowledged Action Plan.

[117] LC 80 Initial Comments of Staff at 3
[118] https://edocs.puc.state.or.us/efdocs/HAQ/um2274haq15385.pdf
[119] LC 80 Initial Comments of Staff at 3

12.5 Bilateral contracts

Staff request an explanation of how PGE will demonstrate to the Commission that the Company has pursued and fairly evaluated all feasible paths for bilateral contracts for capacity.[120]

PGE's Response

PGE continuously participates in the regional capacity and resource adequacy programs to identify opportunities to deliver least-cost, least-risk resource for customers. These bilateral markets will continue to evolve and are likely to result in new non-emitting opportunities that are compatible with PGE's existing resource portfolio. Any negotiations for bilateral capacity products will be informed by available alternative opportunities at the time of negotiation. Upon successful negotiation of a bilateral capacity contract, PGE will bring forward the opportunity and the associated business case for stakeholder and OPUC consideration in the appropriate cost recovery venue while also adjusting procurement levels appropriately within current or future RFPs.

12.6 Details on PGE's evolving RFP process

Energy Advocates seek additional details on how the company is evolving the RFP and where those changes are occurring.

PGE's Response

PGE's regulatory process around the 2023 All-Source RFP is occurring in Docket No. UM 2274. As described above in **Section 12.2**, PGE anticipates periodic updates in both UM 2274 and LC 80 to discuss the alignment between resource planning and acquisition process.

12.7 Benefits for EJ communities

Regarding procurement of energy resources in the Action Plan, Energy Advocates note that "not all MW are equal." They request that PGE prioritize meeting or exceeding Action Plan energy targets with resources that provide the greatest benefit for EJ communities.[121]

PGE's Response

PGE recognizes the importance of considering benefits for EJ communities in the resource acquisition process. We have made community benefits a focus in the CEP/IRP as demonstrated through the inclusion of CBREs in the Action Plan. PGE is beginning acquisition processes now to acquire the resources identified in the Action Plan. In particular, PGE expects that the co-development of an acquisition process to acquire CBRE projects will provide greater indication of how projects could provide tangible benefit for EJ communities. With the knowledge gained through this process, PGE hopes

[120] LC 80 Initial Comments of Staff at 3
[121] LC 80 Initial Comments of Energy Advocates at 11

to further refine our ability to maximize benefits to EJ communities while working within the least cost least risk procurement framework.

12.8 RFP timing and CEP/IRP acknowledgement

CUB expressed concern that issuing the RFP prior to CEP/IRP acknowledgement could be problematic, citing a specific scenario in which resource procurement targets do not reflect EE and DR targets acknowledged through an IRP.[122]

PGE's Response

PGE anticipates that any acquisitions considered through the 2023 All-Source RFP or CBRE acquisition process will align with the 2023 CEP/IRP once an acknowledgment decision is made. Any modification of the Action Plan, including additions to EE and/or DR targets would therefore be reflected in ultimate procurement volume of energy and capacity resources.

Chapter 13. Additional Regulatory Topics

13.1 Inclusion of avoided cost information

NewSun commented that OAR 860-029-0080 (3) requires PGE to provide Avoided Cost information at the time the Company files its IRP.[123]

PGE's response

PGE has complied with and fulfilled the intent of OAR 860-029-0080(3). Avoided costs represent a method to evaluate resources outside portfolio analysis. The avoided costs are thus a combination of the inputs and outputs of portfolio analysis. **Table 6** details the different components of the avoided costs as used in Schedule 201 and where they can either be found or developed based on the information within the CEP/IRP.

Table 6. Components of Avoided Costs

Avoided cost element	Subcomponents	Location	Notes
Capacity	Proxy avoided capacity resource	Chapter 10, Section 10.6	The proxy capacity resource is based on the interpretation of the Preferred Portfolio

[122] LC 80 Initial Comments of CUB at 2
[123] LC 80 Initial Comments of NewSun at 14

Avoided cost element	Subcomponents	Location	Notes
	Avoided capacity cost	Chapter 10, Section 10.6	Avoided capacity cost represents the net cost of new entry of the selected capacity proxy resource
	Capacity contribution	Appendix K	Details the results of tuned ELCC calculations of the IRP proxy resources
Energy	Proxy avoided energy resource	N/A	The proxy resource is based on the interpretation of the Preferred Portfolio
	Avoided energy cost	N/A	Avoided energy cost represents the net cost of new entry of the selected energy proxy resource
	Energy Prices	Appendix H.1.1	Yearly average prices are provided to balance the quantity of data and usability.

13.2 Treatment of RECs

GEI provided detailed comments on the treatment of renewable energy certificates (RECs) under HB 2021, and by extension, in PGE's CEP/IRP. Specifically, GEI argues that statements made in PGE's CEP/IRP are problematic and misleading under the Federal Trade Commission's Green Guides and urges PGE to "reconsider its current assessment of the [HB 2021] law as a generation-based program."[124]

PGE's response

GEI raises a policy issue that was considered and addressed for utility CEPs through the UM 2225 process in 2022.[125] Statements made throughout PGE's CEP/IRP, including those cited by GEI, are consistent with HB 2021 and adopted OPUC guidance. HB 2021 is clear that compliance with emissions targets is not tied to REC retirement, and the legislature provided no linkage to the RPS where RECs are the means of compliance. The RPS is REC-based and the CEP is emissions-based, as reported to the Department of Environmental Quality consistent with longstanding statute and regulatory practice. It is not how much bundled renewable energy (with a REC) is used to serve customers to determine whether

[124] LC 80 Initial Comments of GEI at 10.
[125] See in particular, UM 2225 discussion of RECs at the November 1, 2022 OPUC Regular Public Meeting and in Order No. 22-446, available at

the targets in ORS 469A.410 are met, it is the amount of greenhouse gas emissions produced in doing so. Our CEP/IRP is consistent with this principle.

Policy issues regarding expectations for RECs within HB 2021 implementation have recently been raised by stakeholders in OPUC Docket No. UM 2273, *Investigation into HB 2021 Implementation Issues*. PGE addressed GEI's comments regarding the generation-based nature of HB 2021 in comments filed to UM 2273 in April 2023.[126]

[126] Reply Comments of PGE Regarding Initial Scoping Questions in UM 2273 at 1-2. https://edocs.puc.state.or.us/efdocs/HAC/um2273hac141652.pdf

Appendix A: Comment and Response Crosswalk

This appendix catalogues stakeholders' comments as identified by PGE and provides a reference to the chapter 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	Hdg #	Heading	Sec #	Section
CUB	Accessibility - drafting a CEP that is understandable to non-expert members of the public, particularly for the environmental justice communities	1	Engagement	1.2	Accessibility
CUB	Importance of Decarbonization - modeling should include IRA and IIJA	3	Resource Options	3.1	Impact of tax credits on DERs
CUB	Modeling	11	Portfolio Analysis	11.8	Modeling inputs
CUB	Action Plan - issuing the RFP prior to CEP/IRP acknowledgement could be problematic	12	RFP	12.8	RFP timing and CEP/IRP acknowledgement
Elizabeth Graser-Lindsey	Glidepath - Should take the front-loaded glidepath	2	Annual Progress	2.2	Choice of glidepath
Energy Advocates	HB 2021 is an environmental-justice led policy, so we request that energy justice principles are applied and centered in this transition to clean energy and in the processes leading up to it. At a high level, we encourage PGE to revise its 2023 CEP in consideration of energy justice principles like recognition, distributional, restorative, and procedural justice.	1	Engagement	1.1	Centering energy justice
Energy Advocates	PGE should clearly outline in its CEP how it is advancing distributional justice. We do not see in the CEP our feedback that PGE takes steps or outlines specific actions—such as program concepts with preliminary budgets—that will bring benefits to environmental justice communities beyond the status quo. A successfully revised CEP would clearly outline how the utility is addressing issues that impact the everyday existence of people.	1	Engagement	1.1	Centering energy justice
Energy Advocates	PGE should modify the CEP so that any person can read and understand it without having to also read the IRP. We encourage PGE to revise its CEP with the assistance from organizations and practitioners with expertise in communicating about energy in more accessible ways.	1	Engagement	1.2	Accessibility

Comment Source	Comment	Hdg #	Heading	Sec #	Section
Energy Advocates	We recommend that PGE considers and integrates feedback in the IRP that it receives in other spaces such as the Distribution System Planning, Community Learning Lab, and Clean Energy Plan spaces.	1	Engagement	1.3	Feedback
Energy Advocates	Request that PGE be transparent about the feedback it has received from community members and how it has integrated feedback into its plans or, if it did not, to explain why the company rejected the input. Such an approach not only helps to foster transparency, accountability, and trust in this process but also signals to community members where it is feasible and productive for them to expend their resources and time.	1	Engagement	1.3	Feedback
Energy Advocates	Encourage PGE to reach out to Tribal communities that are in its territory or impacted by its activities to understand Tribal concerns and priorities with regard to HB 2021 implementation. We continue to reiterate the importance of this work being done in a genuine manner as opposed to a check-the-box manner or continuing the status quo of how the company engages with tribes.	1	Engagement	1.4	Tribal engagement
Energy Advocates	We also recommend that PGE take into consideration the Tribal priorities identified in the Columbia River Inter-Tribal Fish Commission's Energy Vision.	1	Engagement	1.4	Tribal engagement
Energy Advocates	Climate recommendation - We also recommend that PGE produce a climate change and extreme weather vulnerability map of communities within its service territory. This map can in turn, be used to identify where resilience and emergency outreach efforts should be prioritized. PGE may consider overlaying its heat vulnerability map with its climate change/extreme weather vulnerability map.	1	Engagement	1.5	Resilience analysis
Energy Advocates	We... encourage PGE to consolidate and integrate its findings here with those of the climate change and heat vulnerability assessments. We also encourage PGE to include all of these findings in a multi-layer map so all of this information can be stored and accessed in one centralized location that is made available to the public. In addition to the resources that PGE has already looked at, we would recommend that PGE consider overlaying data from the US Department of Energy's Climate and Economic Justice (CEJST) screening tool.	1	Engagement	1.5	Resilience analysis
Energy Advocates	Zone of tolerance - we encourage PGE to consider the factors included in the Grid Modernization Lab Consortium (GMLC) resilience report. These factors include: 1. a household's need for utility service; 2. preparedness level; 3. the existence of substitutes; 4. possession of social capital; 5. previous experience with disasters; and 6. risk communication.	1	Engagement	1.5	Resilience analysis

Comment Source	Comment	Hdg #	Heading	Sec #	Section
Energy Advocates	Regarding value of service, Regarding the dynamic survey instrument design, how does PGE plan to select its customer survey respondents, and how many customers in which part of its territory does it plan to survey?	1	Engagement	1.6	Value of service study
Energy Advocates	It may also be useful to have additional technical workshops this year to go over many of the issues involved in transmission planning.	1	Engagement	1.7	Additional technical workshops
Energy Advocates	PGE should specify in this CEP its methodology for tracking continual progress in interim years via emissions reductions. We do not believe that PGE has demonstrated how procuring more supply-side clean energy resources will reduce its emissions.	2	Annual Progress	2.1	Demonstrating annual progress
Energy Advocates	Do the scenario analyses cover the range of potential IRA impacts?	3	Resource Options	3.1	Impact of tax credits on DERs
Energy Advocates	How much does the current NEM policy cause cost shifting? Can PGE provide figures to demonstrate the cost shift caused by NEM?	3	Resource Options	3.2	NEM Policy
Energy Advocates	Why are no QFs expected to renew their contracts? Is there historical data to indicate that no QF contracts will be renewed?	3	Resource Options	3.3	PURPA Qualifying Facilities Contracts
Energy Advocates	Regarding cost and characteristics for supply side resources, Why were 2020 AEO values used rather than more current 2022 or 2023 values?	3	Resource Options	3.4	Resource cost data
Energy Advocates	In other contexts, PGE has relayed that building out DERs may alleviate the need for a certain degree of transmission needs. Would PGE include a cross-reference of this discussion within the Transmission chapter? Describing the reduction or avoidance of transmission costs associated with DER projects would be helpful.	4	Energy Efficiency and Demand Response	4.2	Energy Efficiency and Demand Response Portfolio Modeling
Energy Advocates	In section 12.1.1, PGE provides Table 69 - Cumulative customer resource additions. Can PGE provide some context for these figures? For example, have consumers ever achieved the energy efficiency MWa described in the reference case? PGE also describes that cost-effective energy efficiency has been forecasted by the Energy Trust of Oregon. Can PGE describe the role of ETO and PGE in achieving energy efficiency MWa? To what extent can PGE support the ETO in meeting this requirement?	4	Energy Efficiency and Demand Response	4.3	Energy Efficiency and Demand Response in the Action Plan
Energy Advocates	Likewise, PGE describes in this section DR additions which it forecasted in its DSP part 2. Have these MW figures been achieved by PGE before? What are the steps necessary to achieve these MW? Since these actions are outside of PGE's complete control, i.e., customers have to participate, does PGE have a Plan B if the MW numbers are not met? Will PGE incentivize customers to participate in DR?	4	Energy Efficiency and Demand Response	4.3	Energy Efficiency and Demand Response in the Action Plan
Energy Advocates	First, how did PGE arrive at 10% as the appropriate percentage for the adder? Second, what factors did PGE include in the valuation of CBREs? Did this only include benefits that CBRE projects can provide to PGE, or did it also include	5	Community Benefits Indicators	5.2	CBI valuation

Comment Source	Comment	Hdg #	Heading	Sec #	Section
	benefits to communities that may have CBRE projects or community benefit agreements? If community benefits were considered, how were they identified and correspondingly valued?				
Energy Advocates	It appears that the CBI benefit of 22 = 0.1*(184+28), or 10% of the fixed cost and the energy value). Is this interpretation correct?	5	Community Benefits Indicators	5.2	CBI valuation
Energy Advocates	How will baselines for the energy, equity, health & community wellbeing, and economic CBIs be determined? 2. How will PGE differentiate between benefits that are brought about through HB 2021 implementation from other processes? For example, how will PGE differentiate between the reduction of energy burden that stems from CEP implementation from that of HB2475 interim income qualified bill discount programs?	5	Community Benefits Indicators	5.3	Informational CBIs (iCBIs)
Energy Advocates	PGE should consider an additional environmental informational Community Benefits Indicator. It would be prudent for PGE to add another environmental CBI to its portfolio. We, once again, recommend that PGE adopt an environmental CBI that has been identified by our Tribal partners as important to them - reducing pressure on the Columbia River system.	5	Community Benefits Indicators	5.3	Informational CBIs (iCBIs)
Energy Advocates	How will PGE approach co-developing the CBRE-RFP scoring matrix with community members? Will PGE go into its EJ communities to identify partners to engage in this work, will it work through its UCBIAG on this? How can we ensure that this process is executed well and targets input from actual EJ community members?	6	Community Based Renewable Energy	6.1	CBRE acquisition and community participation
Energy Advocates	Will PGEs collaboration with EJ communities on the CBRE-RFP only be limited to the project scoring matrix?	6	Community Based Renewable Energy	6.1	CBRE acquisition and community participation
Energy Advocates	We agree with PGE that the co-development of future community solutions and resiliency opportunities (including CBRE projects) is important. Energy advocates encourage PGE to seek out community members and develop a company contact list for this and future engagement.	1	Engagement	6.1	CBRE acquisition and community participation
Energy Advocates	Learning Labs - It would be very useful to consider how to incorporate actual community members in this space, as opposed to some community-based organizations and other energy practitioners. Once this is done, we would encourage PGE to consider evolving the space so that it can—as it plans—co-develop future resiliency projects with community members.	1	Engagement	6.1	CBRE acquisition and community participation

Comment Source	Comment	Hdg #	Heading	Sec #	Section
Energy Advocates	Will PGE have a separate process from the CBRE-RFP to go out and solicit or partner with EJ communities on CBRE projects? Our concern here is that many under-resourced communities do not have the experience or resources to plan and build a CBRE-type project and engage in an RFP and may need some capacity building and resource sharing via partnerships to bring about actual community-owned projects.	6	Community Based Renewable Energy	6.2	CBRE acquisition
Energy Advocates	Regarding transmission, Can PGE clarify whether additional MW would be available under this option, or is the South of Allston capped (perhaps due to other flowgate congestion) at 400 MW?	7	Transmission	7.5	Size of SoA upgrade
Energy Advocates	Do the costs in Table 44 for the Generic proxy transmission include the wind energy from Wyoming and solar from Nevada? Said another way, please explain why the costs of the proxy transmission options are so different: $1.97/kW-month for the South Allston upgrade and $20.46/kW-month for the Transmission to Wyoming (similar for transmission to Nevada). An explanation of this difference would be helpful.	7	Transmission	7.6	Clarification of transmission costs
Energy Advocates	Given the lengthy lead times necessary for new transmission, is PGE satisfied that these two transmission projects are sufficient for the foreseeable future?	7	Transmission	7.7	Sufficiency of transmission in Action Plan
Energy Advocates	For example, will these (new clean) resources reduce thermal resource dispatch? Will they result in earlier retirement of emitting resources? How will supply-side resources be optimized with customer-side resources to deliver a balanced portfolio of clean energy resources…	8	Thermal Operations	8.1	Resource Utilization and Optimization
Energy Advocates	To the extent that PGE's thermal facilities continue to emit greenhouse gasses in Oregon while serving unregulated or out-of-state load, the PUC will need to account for these impacts when evaluating whether PGE's CEP and its participation in organized wholesale markets are in the public interest.	9	Emissions	9.3	Retail and Wholesale emissions
Energy Advocates	However, if PGE makes unspecified market purchases outside the EIM, then we recommend that PGE clarify in the CEP that the CO2e intensity could be higher than the ODEQ's specified rate. If this is not the case, please explain.	9	Emissions	9.4	Market unspecified purchase emissions rate
Energy Advocates	What other (GHG variation) factors are there to consider or account for? Are there models that would take these factors into account? We recognize that it is unlikely cost-effective to model all factors, but it would be helpful to know what factors could be modeled but are not, as this analysis may change over time.	9	Emissions	9.5	Factors that impact annual GHG variations
Energy Advocates	PGE should expand on these potential limiting factors and forecast, to the extent possible, their impact on the decarbonization glidepaths, and include applicable strategies for mitigating their impact on emissions reductions.	9	Emissions	9.5	Factors that impact annual GHG variations

Comment Source	Comment	Hdg #	Heading	Sec #	Section
Energy Advocates	To what extent can emissions be reduced by procuring resources from a larger market footprint, which allows for more resource diversity and less dependence on regional hydroelectric generation levels?	9	Emissions	9.6	GHG impacts and resource diversity
Energy Advocates	How were these historical (30-year historical temperature) trends extrapolated into the future to reflect future climate impacts?	10	Modeling Details	10.4	Resource Adequacy Load Modeling
Energy Advocates	PGE illustrates in Table 71 (in the reference forecast) its plan to procure 1,334 MW of wind power by 2030. Approximately how many Wheatridge facilities would this be equivalent to?	10	Modeling Details	10.5	Accesssibility of the IRP quantitative findings
Energy Advocates	Does PGE have more current cost-effectiveness data from ETO for use in this IRP and CEP?	11	Portfolio Analysis	11.2	ETO coordination and EE cost-effectiveness
Energy Advocates	Energy Advocates seek additional details on how the company is evolving the RFP and where those changes are occurring.	12	RFP	12.6	Details on PGE's evolving RFP process
Energy Advocates	Regarding procuring energy resources in the Action Plan, We request that PGE prioritize meeting or exceeding that number by generating, or procuring via contract, non-emitting resources that provide the greatest benefit for EJ communities.	12	RFP	12.7	Benefits for EJ communities
GEI	RECs - primary concern regarding PGE's approach to RECs in the context of HB 2021: how to reconcile the company's interpretation of HB 2021 with the Federal Trade Commission's (FTC) Green Guides, which establish regulations for environmental marketing claims for renewable energy.	13	Additional Regulatory Topics	13.2	Treatment of RECs
Grid United	To Produce a More Robust Analysis of Regional Transmission Needs, PGE Should Include More Proxy Resources in its Analysis of Proxy Transmission Options.	7	Transmission	7.13	Additional transmission proxies
Grid United	PGE's Analysis Should Also Consider Interregional Resource Diversity Achieved Through Interregional Transmission Projects, rather than Focusing Only on Regional Proxy Resources.	7	Transmission	7.13	Additional transmission proxies
NewSun	Expand CBRE resources to include transmission-scale and - interconnected projects (consistent with statutory definitions) and include it in the modeling	6	Community Based Renewable Energy	6.2	CBRE Acquisition
NewSun	Realistic assumptions around the transmission (two main assumptions)	7	Transmission	7.8	Realistic transmission assumptions
NewSun	More detailed analysis of major BPA transmission upgrades, their timelines and work to build those assumptions into the base case.	7	Transmission	7.8	Realistic transmission assumptions
NewSun	Discussion of PGE's proxy transmission resources and the basis upon which PGE determined the cost and availability of those resources.	7	Transmission	7.9	Cost and availability of PGE's proxy transmission resources

Comment Source	Comment	Hdg #	Heading	Sec #	Section
NewSun	25% Fewer Emissions Associated with Market Sales.	11	Portfolio Analysis	11.3	Company-wide emissions & emissions from market sales
NewSun	100% Zero Emissions by 2040 Company-Wide.	11	Portfolio Analysis	11.3	Company-wide emissions & emissions from market sales
NewSun	Unconstrained CBREs	11	Portfolio Analysis	11.4	Unconstrained CBREs
NewSun	Achievable Potential of Distributed Solar	11	Portfolio Analysis	11.4	Unconstrained CBREs
NewSun	Achievable Potential of DERs	11	Portfolio Analysis	11.4	Unconstrained CBREs
NewSun	Provide draft avoided cost information required under OAR 860-029- 0080(3).	13	Additional Regulatory Topics	13.1	Inclusion of avoided cost information
NewSun	Ensure proper comparison of new transmission build costs with West of Cascades, On-System, DER, EE, Solar and Storage resources.	7	Transmission	"7.10"	Proper comparison of transmission with other options
RNW	Community Equity Lens and Engagement Merit Further Explanation and Development - We recommend supplying a plan with more information for how reaching these historically excluded communities will occur. We recommend providing more information on the short-term goals and outcomes. We suggest including more information and a timeline describing PGE's plans for the CBIAG and progress to date. Highly encourage PGE to pursue further Tribal outreach and engagement beyond that described in section 14.2.2.	1	Engagement	1.4	Tribal engagement
RNW	Offshore Wind Likely Merits Additional Discussion	3	Resource Options	3.5	Offshore wind discussion
RNW	Renewable Northwest Recommends Changes to PGE's Approach to Modeling Conditional Firm Transmission	7	Transmission	7.11	Conditional Firm Transmission Approach
RNW	Renewable Northwest Recommends Careful Review of PGE's Approach to Colstrip	8	Thermal Operations	8.2	Colstrip Operations
RNW	Renewable Northwest Recommends Careful Review of PGE's Approach to GHGs	9	Emissions	9.2	CEP/IRP GHG analysis
RNW	Glidepath discount rate and SCC	9	Emissions	9.2	CEP/IRP GHG analysis
RNW	PGE's Post-2030 Plan Is Unclear	11	Portfolio Analysis	11.5	Post 2030 resource plan

Comment Source	Comment	Hdg #	Heading	Sec #	Section
RNW	PGE's Transmission Assumptions Are Likely Discounting the Value of Hybrid Resources and Driving Up Its Capacity Need	11	Portfolio Analysis	11.6	Hybrid resources
RNW	CBIs and CBREs Merit Further Explanation and Development - more clarity on the choice of a 10% adder for the Resource Community Benefits Indicator ("rCBI"). We would like to know more information on the valuation of CBREs. What factors were considered here? Were benefits to communities considered in addition to benefits to PGE, and if so, how were they identified and valued?	5, 6	Community Benefits Indicators, Community Based Renewable Energy	5.2, 6.1	CBI valuation, CBRE acquisition and community participation
RNW	CBIs and CBREs Merit Further Explanation and Development - more clarity on the choice of a 10% adder for the Resource Community Benefits Indicator ("rCBI"). We would like to know more information on the valuation of CBREs. What factors were considered here? Were benefits to communities considered in addition to benefits to PGE, and if so, how were they identified and valued?	6	Community Based Renewable Energy		CBI development and CBRE RFP
Swan Lake and Goldendale Energy Projects	Pumped storage is not an "emerging technology" and listing it as such may violate the Commission's IRP Guidelines pertaining to fairly comparing resources.	3	Resource Options	3.6	Pumped hydro characteristics
Swan Lake and Goldendale Energy Projects	PGE either leaves out, or relies on incorrect assumptions for, pumped storage throughout the IRP.	3	Resource Options	3.6	Pumped hydro characteristics
Swan Lake and Goldendale Energy Projects	PGE's IRP Favors Batteries Partly as a Result of Unclear, and Likely Inaccurate, Assumptions About the Useful Life of Pumped Storage Projects and PGE's Possible Failure to Factor in Tax Incentives in its Analysis of Pumped Storage.	3	Resource Options	3.6	Pumped hydro characteristics
Swan Lake and Goldendale Energy Projects	Pumped Storage Has Major Benefits to the Transmission Needs Identified in the IRP that Should be Considered in the IRP.	7	Transmission	7.12	Transmission benefits of pumped hydro
Swan Lake and Goldendale	The IRP Relies Too Heavily on Batteries.	11	Portfolio Analysis	11.7	Reliance on batteries

Comment Source	Comment	Hdg #	Heading	Sec #	Section
Energy Projects					
Staff	While there is an aspect of muddling through in this planning environment, the emissions reduction target years are quickly approaching and impacts to environmental justice communities continue. In light of this complexity, it will be important for PGE to focus on collaboration with its communities and stakeholders toward the articulation of an accessible, just, and comprehensive decarbonization strategy.	1	Engagement	1.2	Accessibility
Staff	Provide an explanation for not adopting recommendations made by community groups in the plan reflecting UM 2225 guidelines.	1	Engagement	1.3	Feedback
Staff	Expand the accountability analysis to include key input received in traditional IRP Roundtables, to the extent feasible.	1	Engagement	1.3	Feedback
Staff	Further explanation for prioritizing short term cost impacts over long-term reductions in cost and risk and how PGE considered the loading order adopted in Senate Bill 1547(CiteORS75754(3)).	4	Energy Efficiency and Demand Response	4.1	Approach to Energy Efficiency and Demand Response
Staff	An update to the Action Plan to enable the ETO to pursue additional cost-effective energy efficiency or a justification for not including such an item in the Action Plan.	4	Energy Efficiency and Demand Response	4.1	Approach to Energy Efficiency and Demand Response
Staff	Explanation of how PGE considered HB 2021 rules that direct electric utilities to evaluate non-emitting resources, energy efficiency and demand response resources to meet clean energy targets.	4	Energy Efficiency and Demand Response	4.1	Approach to Energy Efficiency and Demand Response
Staff	An analysis of a separate portfolio that applies the same constraints that were used to design the Preferred Portfolio, but also incorporates the 50 MWa of additional EE that was tested in Portfolio 36.	4	Energy Efficiency and Demand Response	4.2	Energy Efficiency and Demand Response Portfolio Modeling
Staff	An analysis of another separate portfolio that has the 50 MWa of additional EE and the same constraints as the Preferred Portfolio but does not force in the SoA upgrade	4	Energy Efficiency and Demand Response	4.2	Energy Efficiency and Demand Response Portfolio Modeling
Staff	Resolution of any discrepancy in the statements regarding consideration of cost effective and non-cost-effective demand response resources in the Action Plan. If PGE does not believe there is a discrepancy, Staff requests that the Company provide an explanation.	4	Energy Efficiency and Demand Response	4.3	Energy Efficiency and Demand Response in the Action Plan
Staff	Update the IRP/CEP explaining why PGE chose the two CBIs to inform its preferred portfolio and provide details regarding how these two CBIs reflect benefits in the five categories discussed above.	5	Community Benefits Indicators	5.1	CBI selection

Comment Source	Comment	Hdg #	Heading	Sec #	Section
Staff	Provide an explanation of how PGE plans to keep its CBRE RFP equally accessible to both community-specific renewable energy and professional QF developers.	6	Community Based Renewable Energy	6.1	CBRE acquisition and community participation
Staff	To the extent feasible, provide a description of the various opportunities PGE might explore to acquire targeted CBRE resources.	6	Community Based Renewable Energy	6.2	CBRE acquisition
Staff	A clearer description of whether and how the transmission upgrades in the Action Plan are modeled in portfolio analysis.	7	Transmission	7.1	Modeling of transmission upgrades
Staff	A clearer description of how the proxy transmission in the Preferred Portfolio meets PGE's needs and why it is not directly addressed within the Action Plan.	7	Transmission	7.1	Modeling of transmission upgrades
Staff	Quantitatively identifying the impact of the proposed transmission upgrades in the Action Plan on PGE's ability to deliver generation to load.	7	Transmission	7.2	Quantitative impact of transmission in Action Plan
Staff	Clear identification in Chapter 9 Transmission of the portfolio constraints that drive transmission needs (load service, renewable deliverability, or both).	7	Transmission	7.3	Drivers of transmission needs
Staff	Clear identification in Chapter 9 Transmission of the resource options that are available to the model can help avoid transmission upgrades. For example, are the battery systems modeled assumed to be on- or off-system or sited to alleviate transmission constraints during constrained periods? Is the additional EE able to reduce the need for transmission upgrades?	7	Transmission	7.4	Resource options that can avoid transmission
Staff	Shifting generation/emissions from retail to wholesale and operational realities/constraints	8	Thermal Operations	8.1	Resource Utilization and Optimization
Staff	A quantitative and qualitative discussion of the implications of the intermediary GHG modeling approach regarding the delivery of Colstrip generation to PGE customers.	8	Thermal Operations	8.2	Colstrip Operations
Staff	A more thorough description of the assumptions and logic used in the intermediary GHG model to allocate generation between retail load and wholesale market sales.	9	Emissions	9.1	Intermediary GHG model detail
Staff	Any analysis or discussion that will help parties better understand how the current Action Plan might impact their position in the WRAP or their engagement in ongoing design elements, and/or how the implementation of the WRAP could influence the Action Plan	10	Modeling Details	10.1	Regional adequacy programs
Staff	More in this section that explains key drivers for the shape of costs over time for the preferred portfolio.	10	Modeling Details	10.2	Post 2030 price impacts
Staff	An explanation of why the High QF case has a much lower impact on energy needs compared to the Low QF scenario.	10	Modeling Details	10.3	QF Sensitivities

Comment Source	Comment	Hdg #	Heading	Sec #	Section
Staff	Inclusion of a portfolio showing a 2025 exit of Colstrip and comparison to portfolios with a Colstrip exit in 2029 with respect to cost, risk, pace of GHG emissions reductions, and community impacts and benefits.	11	Portfolio Analysis	11.1	Portfolio with Colstip exit in 2025
Staff	Clarification on whether PGE is seeking acknowledgement of any aspect of the accelerated procurement approach beyond the 2023 All Source RFP in this IRP/CEP.	12	RFP	12.1	Acknowledgement of accelerated procurement
Staff	A description of its preliminary expectations for overlapping elements of this IRP/CEP that will inform the development and/or execution of the concurrent RFP and how parties can keep the two dockets aligned—substantively and procedurally.	12	RFP	12.2	CEP/IRP-RFP Topic Expectations
Staff	Additional clarity about how the approach to the proposed 2023 RFP (See Docket No. UM 2274) may differ from the strategy for ongoing procurements after that.	12	RFP	12.3	2023 RFP approach
Staff	Explanation of how the RFPs for non-emitting energy will be adjusted in response to CBRE acquisition. How will these two RFPs be timed?	12	RFP	12.4	CBREs influence on RFPs
Staff	Explanation of how PGE will demonstrate to the Commission that they have pursued and fairly evaluated all feasible paths for bilateral contracts for capacity.	12	RFP	12.5	Bilateral contracts
Staff	An analysis of near-term cost impact of the 50 MWa of additional EE and an explanation of execution risks.	4	Energy Efficiency and Demand Response	4.1, 4.2	Approach to Energy Efficiency and Demand Response; Energy Efficiency and Demand Response Portfolio Modeling