Portland General Electric Company
121 SW Salmon Street • 1WTC0306 • Portland, OR 97204
portlandgeneral.com

October 5, 2022

Via Electronic Filing

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

Re: UM 2225 Investigation into Clean Energy Plans; Comments on Staff's Straw Proposal for Analytical Improvements for Clean Energy Plans Portland General Electric Company

Dear Filing Center:

Enclosed are PGE's initial comments on Staff's Straw Proposal on Analytical Improvements. PGE appreciates Staff's work developing its Straw Proposal and the opportunity to provide feedback to help develop guidance that advance the State's decarbonization goals and provides additional transparency in how utilities plan to meet the decarbonization goals. Our comments regarding Staff's proposal are intended to meet these goals, while also ensuring they do not unduly burden electric utilities' Integrated Resource Plans (IRPs) with new requirements that are not directly related to resource planning in the near-term. We understand that Clean Energy Plans (CEPs) will evolve the IRP over time and hope that initial guidance established through the current process accounts for the time needed to effectively engage and collaborate with communities on such topics as community benefit indicators, resiliency, and community-based renewables, while balancing the need to quickly procure clean energy resources needed to meet our decarbonization goals by 2030.

Please direct questions or comments to Stefan Brown at (503) 464-8172. We look forward to further engagement with Staff and stakeholders on our approach.

Sincerely,
/s/ Shay LaBray
Shay LaBray
Senior Director, Regulation & Regulatory Affairs

/s/ Kristen Sheeran
Kristen Sheeran
Director, Resource Planning and Sustainability

Chapter 1 – Planning for Decarbonization Targets Straw Proposal

Topic #1. Clean technology scenarios

Clean hydrogen – Staff recommendation

> Staff recommends that the utilities test at least one scenario where clean hydrogen becomes available for selection before 2040.

Long duration storage – Staff recommendation

> Staff recommends that the utilities test at least one scenario where long duration storage (e.g. storage with several days of duration or seasonal storage) becomes available for selection before 2040.

Offshore wind – Staff recommendation

> Staff recommends that the utilities test at least one scenario where offshore wind becomes available for selection before 2040.

PGE response

PGE appreciates Staff's recommendation to identify how the long-term availability of each of the clean technology resource options could influence near-term actions. PGE also appreciates that Staff would like utilities to include nascent generation technologies as a scenario in IRPs. PGE is conducting research to further understand emerging technologies such as clean hydrogen that may inform Staff's desire to "understand what implications these technologies might have on how the system is operated, and how the availability of these technologies might change the utility's strategy". PGE is also pursuing opportunities to test and deploy hydrogen technologies to improve our understanding of how these technologies might contribute to our resource needs through partnerships such as Electric Power Research Institute's (EPRI's) Low Carbon Resources Initiative (LCRI).[1]

Though Staff acknowledges that the "cost uncertainty for some of these technologies is high, and that technologies are likely to be commercially available earlier than 2040", Staff's recommendation also asks utilities to "develop a reasonable estimate of when a new technology is likely to be available". PGE's concern is that data availability regarding technology maturity, construction and operational costs of hydrogen and long-term duration storage are too uncertain to include in the 2023 IRP without exacerbating planning uncertainties and thereby complicating discussions on best near-term courses of action. PGE notes that technology investments incur technology development, market, and future regulatory risks that may not be easily identified or quantified. PGE could provide a table of updates on hydrogen and long-term duration storage to help inform discussion of when the right time might be to incorporate these emerging technologies into future IRPs or other planning processes.

---

[1] EPRI's LCRI can be found at https://www.epri.com/lcri.

Regarding emerging technologies, PGE can test action plan robustness by modeling a generic carbon free dispatchable resource, and a generic long duration storage resource. This can include providing cost insights that emerging technologies must meet to result in a change of resource actions or the operational characteristics of the resources to address the need identified in the 2023 IRP. For example, offshore wind is a more developed utility scale resource than hydrogen or long duration storage. PGE has an offshore wind profile it can utilize in the 2023 IRP, which includes rough cost estimates. PGE recommends Staff revise its proposed guidance to provide utilities a flexible approach to modeling emerging clean technologies in their IRPs in the near-term.

Revised language could read:

> *Staff recommends that the utilities test at least one scenario where emerging clean technologies for generation and/or storage become available for selection before 2040.*

Staff question for workshop

> Is the phrase "Clean Hydrogen" clear enough about which types of hydrogen may be included while providing flexibility for utility implementation in consultation with DEQ's determinations of emissions of forecasted resources?

PGE response

PGE recommends that the Public Utility Commission of Oregon (Commission or OPUC) adopt a definition for clean hydrogen that aligns with industry standards, while also giving flexibility for this emerging technology to change over time. For example, the U.S. Department of Energy (DOE) recently released their draft Clean Hydrogen Production Standard (CHPS) aimed at standardizing how carbon intensity of hydrogen is measured.[2] In lieu of a formal definition for "clean hydrogen", currently PGE refers to clean hydrogen as encompassing all hydrogen generation with a carbon output below the current unspecified market rate of 0.43 MMT/MWh. Also, as hydrogen technology rapidly evolves, PGE notes that early hydrogen technology utilization – if not zero-carbon – will have to evolve along with HB 2021's decarbonization targets until utilities get to a zero-carbon system in 2040. More strictly defining "clean" hydrogen in 2022 beyond "generation that helps drive emissions downward compared to market purchases" may make the technology more expensive and could delay implementation.

Topic #2. Demand scenarios

Electrification – Staff recommendation

> Staff recommends that the utilities adopt realistic electrification assumptions in the IRP Reference Case and test at least one High Electrification scenario in which electric demand aligns with the electric technology adoption assumptions that the Company clearly articulates in their IRP

[2] US DOE's CHPS can be found at https://www.hydrogen.energy.gov/pdfs/clean-hydrogen-production-standard.pdf.

PGE response

PGE appreciates Staff's desire to utilize electrification assumptions and analysis in IRP processes. Currently, PGE incorporates realistic electrification assumptions in our IRP Reference Case and tests high electrification scenarios. Per the initial proposed guidelines approved by the Commission on December 23, 2020, in Docket UM 2005, investor-owned utilities forecast load growth, distributed energy resource, and electric vehicle (EV) adoption. This guideline is intended to ensure that utilities "accurately" forecast EV growth, including a high, medium, and low scenarios.[3] To ensure consistency between plans, PGE has utilized Distribution System Plan (DSP) outputs and modeling work for IRP modeling process.

Where feasible, PGE updates DSP outputs and models as needed for use in the IRP as well as other plans such as its Transportation Electrification Plan. For example, PGE considers policy drivers in its load forecasts and will continue to evaluate the effects of those policy drivers on load. These policy drivers are transforming the energy space and will certainly impact how our customers use electricity in the future. PGE continues to explore these impacts further, which will be leveraged to improve our planning processes.

Therefore, it appears that the current practice should fulfill Staff's recommendation. However, PGE understands that we may be misunderstanding the recommendation. PGE is, therefore, open to a discussion regarding the recommendation and/or the gap which Staff may be trying to address with this recommendation. If not, PGE encourages Staff to look to UM 2005 and consider refining additional electrification analysis requirements during the finalization of the DSP guidelines.

Climate change and extreme weather – Staff recommendation

> Staff recommends that the utilities test at least one scenario that accounts for the potential for more frequent extreme weather events, based on a publicly available forecast of climate change related weather impacts. (Utilities should also work toward including climate change in reference case long-term IRP forecasts. This scenario should look at a more extreme climate scenario than the reference case.) If a utility does not quantitatively evaluate such a scenario, Staff recommends that the utility describe the key weather events that drive resource adequacy challenges on their system and quantify how frequently those events have occurred across the historical record.

PGE response

PGE agrees it is necessary to include climate change-related impacts in scenario and planning analysis, not just in the CEP/IRP, but also in planning processes such as the DSP. This analysis will strengthen the ability of PGE's grid to anticipate climate threats, adapt to future weather, withstand and recover from disruptive events. We ask that the Commission provide flexibility in how utilities approach climate change weather modeling and how and where it gets applied within the planning processes. Given the complexity and the work currently underway to develop and incorporate climate related impact scenarios, PGE suggests that Staff broadly request utilities to describe their existing processes for determining and conducting climate

[3] See Commission Order No. 20-485, in Appendix A, starting on page 26. https://apps.puc.state.or.us/orders/2020ords/20-485.pdf.

change-related impacts and analysis as well as how they intend to integrate climate change related analysis into their future planning analysis (e.g., load forecasting, IRP, CEP and/or DSP).

For example, since Order 20-152, PGE has devoted significant resources towards developing an understanding of where and how climate adaptation should be incorporated into the IRP.[4] As discussed in PGE's April 2022 IRP Roundtable, we are currently working to develop an effective view of future climate scenarios and expected risk in our service area through a Climate Adaption Study.[5] This study is being conducted by a third party, Creative Renewable Solutions, on behalf of PGE. PGE expects the study to be complete early in 2023. The results of the study will be discussed in upcoming IRP roundtables as well as PGE's 2023 IRP. Before adding new direction, PGE recommends the Commission allow PGE to proceed with this existing work and collaborate with Staff and Stakeholders to determine the most appropriate next steps.

Staff questions for workshop

> Is requiring "realistic electrification assumptions" clear enough language? Staff's goal is to recognize the uncertainty surrounding policies to decarbonize other sectors while also highlighting the need to begin testing the policies' impact on the electric system to the extent feasible?

PGE response

As noted earlier in PGE's comments, rather than creating additional guidance, PGE recommends the DSP be leveraged to define realistic electrification assumptions. However, given the high uncertainty surrounding decarbonization pathways likely to be taken in other sectors, a robust treatment of possible pathways, as exhibited in our Deep Decarb study as well as in the State of Oregon's The Transformational Integrated Greenhouse Gas Emissions Reduction (TIGHGER) study, represent useful bookends to determine possible worst case scenarios.[6] Within this framework, it will be important to advance a better understanding of what are the lowest cost pathways and emerging policies so that more targeted analysis of likely trajectories can be undertaken.

> Are electrification scenarios most useful for examining the preferred portfolio over time or comparing portfolios?

PGE response

Electrification scenarios are most useful, given that they represent just the changing amount of load due to decarbonization and electrification that would impact PGE's resource need. Portfolio analysis is more tailored for evaluating various options to serve load, as opposed to changes to load levels.

---

[4] See Commission Order No. 20-152, page 16. https://apps.puc.state.or.us/orders/2020ords/20-152.pdf.

[5] PGE's April 2022 IRP Roundtable slides, beginning on slide 25. https://assets.ctfassets.net/416ywc1laqmd/7b7HWYRGD36HHCHeWbBqYS/c17bd893aa9118ad2911293e680ed35f/IRP_Roundtable_April_22-4.pdf.

[6] PGE's 2019 Exploring Pathways to Deep Decarbonization Study can be found at https://assets.ctfassets.net/416ywc1laqmd/2WzCHrdAKz3InBbp0ecdD8/57c8695890d8d3ee4b09f39c2089548b/exploring-pathways-to-deep-decarbonization-PGE-service-territory.pdf. The State of Oregon's TIGHGER report can be found at https://www.keeporegoncool.org/tighger.

Topic #3. Regional development scenarios

Participation in a regional Resource Adequacy (RA) program – Staff recommendation

> Staff recommends that the utilities test a scenario that demonstrates the portfolio impacts of participation in a regional RA program. In this scenario, the utility should demonstrate how the load and resource diversity benefits of a regional RA program would affect their resource needs and resource decisions.

PGE response

PGE notes that resource adequacy (RA) programs such as the Western Power Pool's (WPP) Western Resource Adequacy Program (WRAP) are focused on a shorter time horizon and use different methodologies than the IRP. For example, the qualifying capacity contribution (QCC), similar to capacity value, of resources used in the WRAP is based on critical capacity hours in the program footprint, and results in different reliability metrics than the IRP. The WPP WRAP then assigns participants' planning reserve margins (PRMs) that again differ from the IRPs. These methodological differences need to be acknowledged and a discussion begun on how or whether they should be reported in the IRP/CEP.

In terms of time horizons, the WRAP focuses on RA planning in the near-term, seven months ahead of a peak season, while the IRP focuses on a long-term 20-year planning horizon. While an IRP can better position a utility to be resource adequate seven months ahead of peak season in the WPP WRAP, the converse is not true. Namely, being resource adequate in the WRAP does not translate into reliably and cost-effectively meeting IRP obligations over the long-term 20-year planning horizon. The diversity value Staff referenced is captured by the WRAP in the days of operation when load responsible entities (whether utilities or electricity service suppliers) might be capacity short – not something modeled in an IRP. The following summary demonstrates the different time scale of the WPP WRAP.

- The Southwest Power Pool (SPP) calculates planning reserve margins (PRMs) for the months during the peak seasons (Summer – June 1st through September 15th, and Winter – November 1 through March 15th).
- WRAP participants then submit their forward showing plans showing how the total QCC of their resources and contracts (along with sufficiently firm transmission) meets their load plus PRM for each month.
- WPP WRAP participants submitted these forward-showing RA planning workbooks for the winter 2022-23 season in mid-September, and for summer 2023 in early October.
- A rolling multi-day ahead assessment is then undertaken during the binding seasons by the WRAP Program Operator. This is referred to as the operational program.
- If a participant is deficient, the WRAP Program Operator initiates a sharing event, requiring those with excess capacity to hold it back in preparation for a potential Energy Deployment on the Operating Day.

Once the WPP's WRAP process is mature and the modeling parameters of such a regional system are well-established, PGE can more meaningfully undertake consideration of this modeling effort. Until assumptions around how resources are shared, what RA obligations utilities have, and associated penalties and costs are established, PGE would not be able to determine whether this analysis is feasible and, therefore, PGE does not support Staff's recommendation at this time.

Transmission utilization – Staff recommendation

> Staff recommends that the utilities test a scenario where access to transmission is not limited by current transmission rights. This scenario could, for example, explore the implications of the establishment of a regional transmission operator, participation in a regional organized market, and/or other measures that could result in improved efficiency of transmission operations or contracts.

PGE response

PGE agrees with Staff that analysis of transmission availability is useful. PGE plans to include a scenario and/or analysis in our 2023 IRP and/or CEP that examines proxy generation additions unconstrained by physical transmission or transmission rights. This scenario will contrast which proxy resources are selected when transmission is unconstrained versus which resources are selected together within transmission rights to ensure reliable load/resource balance.

While PGE expects to include an unconstrained transmission scenario, it is worth noting that such an assumption does not reflect the current state, nor does it reflect the ability to acquire transmission rights if a Regional Transmission Operator (RTO) were to operate the transmission system in the Pacific Northwest. That is, there would almost certainly still be constraints on the current system, even with an RTO.

Again, while PGE understands the value of running a scenario in which the RTO and/or independent system operator (ISO) is established and operating, the RTO/ISO does not operate with completely open transmission. Firm transmission rights and reserved transmission capacity still exist as a foundational tenet of RTO/ISO structures. PGE could build a scenario in which an RTO/ISO exists in the Pacific Northwest, but the number of theorical assumptions PGE would need to make would likely render such an exercise of little overall value. Such assumptions would need to consider, but not be limited to, whether Bonneville Power Administration (BPA) or other public utilities would participate and at what level of participation, what rules govern operation of the RTO/ISO and whether such rules are more closely related to California independent system operator (CAISO) rules or SPP or Midcontinent ISO.

Similarly, not all ISOs treat RA similarly, nor do they treat energy efficiency and other distributed energy resources (DERs) measures similarly. PGE may be willing to undertake this modeling effort, but it would likely require significant resources, many assumptions and have unanswerable or open questions. PGE suggests that, if such a modeling exercise is of some value to the Commission and stakeholders, an additional, separate process be opened to explore how an ISO and additional transmission modeling can be incorporated into future IRP and/or CEP modeling.

Additionally, PGE believes modeling of the region's transmission system operated by an RTO must include analysis of the associated RTO cost elements, such as transmission access. For example, a failure to account for these likely cost elements will result in an analysis that misrepresents the impacts of participating in an RTO for PGE's customers.

PGE looks forward to working with Staff and stakeholders to consider potential RTO analysis in future IRP/CEPs.

Regional transmission expansion – Staff recommendation

> Staff recommends that the utilities test a scenario where regional transmission expansion enables access to more diverse renewable resources.

PGE response

PGE agrees with Staff that analysis of regional transmission expansion is useful. As introduced during PGE's September 2022 IRP roundtable meeting, PGE is planning analysis to explore the expansion of PGE's transmission system and/or transmission rights to allow access to climate zones that are less correlated to Pacific Northwest renewables.[7] PGE expects that transmission expansion analysis will be part of the 2023 IRP portfolio modeling process.

Regional development scenarios – Staff recommendation

> Staff recommends that the utility test at least one of the technology scenarios with and without participation in an organized market with liberalized transmission or in a regional transmission expansion scenario.

PGE response

PGE is concerned that this recommendation will not lead to meaningful analysis in the CEP at this time. However, assessing the impact of an organized market on resource diversity benefit and transmission availability could be informative once there is more certainty.

Participation in an organized market does not necessarily lead to liberalized or increased transmission availability. BPA uses concepts employed in organized markets in planning and allocating transmission capacity on their system. For example, BPA also quantifies total transfer capability (TTC) on their system using a flow-based methodology which is very similar to how organized transmission markets determines TTC. Because of this, it should not be assumed that moving to an organized market will unlock hidden transmission system capacity or create new transmission capacity.

Staff questions for workshop

> Would it be meaningful to discuss the difference between a forward showing RA program and an operational/reserve sharing program?

PGE response

The WPP WRAP has two components: a forward showing program; and an operational program. The forward showing program looks into the future in order to determine if participants are planning to meet standardized reliability metrics established to ensure the program's footprint has enough capacity to be resource adequate during peak season. The operational program ("ops program") runs during the peak seasons and would require those with excess capacity to hold it back should other participants signal they need the energy. This RA ops program is distinct from the contingency reserve sharing program for balancing

---

[7] PGE's IRP Roundtable recorded meetings and materials can be found at https://portlandgeneral.com/about/who-we-are/resource-planning/irp-public-meetings.

authorities currently operated by the WPP. To avoid conflation, further discussion of these three programs would be worthwhile.

> Are there other high priority transmission scenarios or combinations of transmission and technologies?

PGE response

Yes, PGE will need to explore options to increase the deliverability of potential new remote resources to PGE's customers. PGE has historically been heavily reliant on BPA's transmission system to serve load. Recently, BPA stated during a public workshop that their system is essentially fully subscribed.[8] While PGE will explore local, community-based resource options, other non-emitting resources will also be necessary.

Topic #4. GHG emissions constraints in IRP modeling

2030 and 2035 weather modeling – Staff recommendation

> The IRP should achieve the 2030 and 2035 clean energy targets under typical or expected weather and hydro conditions in those years. The utility should demonstrate this for the Preferred Portfolio, any alternative portfolios that were considered for selection or in designing the Action Plan, and in all of the technology, demand, and regional development scenarios tested by the utility.

PGE response

PGE intends to analyze a variety of C-levels for comparison to understand the distribution of weather and hydro impacts to PGE's thermal usage. PGE seeks clarity as to Staff's intention for this recommendation and the associated compliance with HB 2021 if the IRP utilizes C-50 scenario assumptions to meet the established emissions reduction targets. PGE also seeks clarity regarding the impacts of including planning assumptions with a 50% chance of meeting targets under actual conditions: under expected weather, plant operations, and hydro conditions (also referred to as C-50 scenario).

2040 weather modeling – Staff recommendation

> The IRP should achieve the 2040 clean energy target across the same weather and hydro conditions that are considered within the utility's resource adequacy analysis. More specifically, the utility must show that in 2040, the portfolio can achieve resource adequacy with no GHG emissions. The utility should demonstrate this for the Preferred Portfolio, any alternative portfolios that were considered for selection or in designing the Action Plan, and in all of the technology, demand, and regional development scenarios tested by the utility.

PGE response

PGE does not believe this guidance is necessary at this time. In PGE's 2023 IRP, we are already including plans to be resource adequate in 2040 with no greenhouse gas (GHG) emissions. If

---

[8] See BPA's presentation at [PowerPoint Presentation (bpa.gov)](), page 6.

resource adequacy cannot be achieved with known technologies, then the IRP should include a discussion of that finding.

Topic #5. Key long-term decarbonization planning questions

Staff recommended that utilities use the scenarios described in Topics #1-3 to explore the following long-term planning questions and to include narrative (and quantitative where possible) answers to those questions within their CEPs.

Narrative requirement #1 – Staff recommendation

> What low regrets near term actions perform relatively well across all of the scenarios?

PGE response

PGE believes this recommendation is already captured as a central tenant of IRP development. However, PGE is open to further discussions to understand and get specificity on what is intended by low regrets, near-term actions not presently included in utility IRP activities.

Narrative requirement #2 – Staff recommendation

> What near term actions might have large negative consequences (in terms of cost, risk, GHG emissions, or community impacts or benefits) under one or more of the scenarios?

PGE response

PGE believes the majority of this recommendation is already captured in existing IRP requirements. The practice of developing a traditional IRP is to model and balance risks and the consequences of known or forecasted risks and their consequences regarding costs and other important state and federal policies such as environmental, greenhouse gas emission and ratepayer benefits and costs. Community impacts and benefits are a new consideration for the IRP process, and near-term actions which may have negative consequences to our communities are currently considered in other planning processes. PGE intends to continue its work regarding community impacts and benefits and leverage it to evolve the IRP.

Narrative requirement #3 – Staff recommendation

> Are there any critical junctures in relation to the scenarios at which the utility's strategy would materially change and what indicators will the utility use to identify whether those junctures are approaching?

PGE response

PGE believes this recommendation is already captured in existing IRP requirements. Broadly critical junctures, milestones, or decisions points are part of IRP modeling. For example, past IRPs have placed significant weight on natural gas prices and have attempted to model a natural gas market over the term of years covered by the IRP. Where the modeled natural gas prices materially change, so do the strategies employed by the IRP generally. The preferred portfolios modeled in the IRP will change in an attempt to find the new least cost planning scenario. Therefore, PGE believes that current IRP practices identify and manage critical junctures within the parameters of the existing IRP requirements and PUC guidance. PGE is open to working with Staff and stakeholders to identify new junctures which are not captured within the existing IRP process.

Narrative requirement #4 – Staff recommendation

> Does the utility's long-term plan or the expected performance of the long-term plan have any critical dependencies related to the uncertainties explored through scenarios (e.g. availability of a technology or transmission infrastructure, or the expansion of regional coordination)? What would the implications be for the long-term plan if one or more of these scenarios were to occur?

PGE response

PGE believes this recommendation is already captured in existing IRP requirements. As part of the IRP process the utilities conduct stakeholder meetings to address concerns such as the ones outline above by Staff. These stakeholder meetings are meant to raise questions such as critical dependencies around regional coordination. Where and when possible, the utilities undertake best efforts to address a knowledge gap which may include the development of a scenario. PGE is open to working with Staff and stakeholders to identify any critical dependencies related to the uncertainties explored through scenarios.

Narrative requirement #5 – Staff recommendation

> What barriers to implementation would need to be addressed to implement the utility's long-term plan under each scenario? Which of these barriers can be addressed by the utility or the Commission and which of these barriers are out of the utility's or the Commission's control? Which of these barriers would need to be addressed in the next 5- 10 years?

PGE response

PGE agrees it will be important to identify barriers to implementing our long-term plans. When developing an IRP, PGE does take into account risks, including barriers to implementation, and looks forward to discussing with Staff, stakeholders, and the Commission additional barriers as described within Staff's recommendation.

Chapter 2 – Treatment of Fossil Fuel Resources Straw Proposal

Topic #1. Fossil fuel retirements and conversions

Specific retirement modeling requirements – Staff recommendation

> Staff proposes that specific requirements for modeling retirements or conversions does not need to be prioritized for the first IRP/CEP but expects that this capability be adopted for future planning cycles.

PGE response

PGE appreciates Staff proposal to not recommend requiring plant retirement or conversion in the first IRP/CEP. PGE is open to working with stakeholders to determine whether changes to PGE's analytical process is warranted for future IRP/CEPs.

Fossil Fuel Retirements and Conversions – Staff recommendation

> Staff also encourages the utilities to be clear about their rationale for including or not including conversions in this first IRP/CEP.

PGE response

PGE appreciates Staff encouraging utilities to be clear about their rationale for including or not including conversions in this first IRP/CEP. As a general best practice, PGE makes every effort to be transparent about decisions made within our IRP and will continue to do so as the IRP shows feasible pathways to emissions reduction targets. Accordingly, PGE does not believe the Commission needs to provide guidance on this topic.

Topic #2. Fossil fuel resource operational changes

Operational changes – Staff recommendation

> If the Preferred Portfolio relies on operational constraints or other non-market-based reductions to the dispatch of fossil fuel resources within the Action Plan window, the utility should describe how it intends to implement those operational changes within the Action Plan. Will operational constraints be placed on individual units, or on the system as a whole?

PGE response

PGE believes that this recommendation goes beyond the scope of HB 2021 as the CEP/IRP are planning documents whereas this appears to call for actual resource operation information. Actual conditions might differ significantly from the conditions forecasted in planning documents. PGE therefore recommends that the Commission decline to adopt this guidance.

Out of state sales – Staff recommendation

> If the Preferred Portfolio relies on sales of fossil fuel-based generation to out-of-state counterparties to achieve the clean energy targets set forth in HB 2021, the utility should quantify those sales and the associated GHG emissions.
>
> If the Preferred Portfolio relies on sales of fossil fuel-based generation to out-of-state counterparties within the Acton Plan window, the utility should describe how it intends to make those sales within the Action Plan.

PGE response

PGE recommends that the Commission decline to adopt this guidance because it is outside the scope of the requirements in HB 2021.

While HB 2021's emission reduction targets only apply to the emissions associated with serving the Company's retail sales, PGE understands the value from a planning perspective of transparently showing input assumptions on emission rates and thermal operations as well as their resulting forecasts of emissions and generation. PGE does note that these forecasts will represent a long-term planning view, not actual operations.

Chapter 3 – Additional Data Transparency Straw Proposal

Topic #1. GHG emissions

Western Interconnect GHG reporting – Staff recommendation

> Utilities should report the total estimated annual GHG emissions across the Western Interconnect under various portfolios, including the Preferred Portfolio.

PGE response

This recommendation is outside the scope of individual utility planning under the CEP as it is a regional effort. PGE anticipates modeling future load and resource balance and GHG emissions associated with serving customer load, in compliance with HB 2021. PGE can pull from publicly available sources to provide a narrative on how its thermal resources fit within Western Electricity Coordinating Council (WECC) wide needs. However, PGE is not able to provide a WECC-wide modeling forecast, as this would require assumptions on the future resource actions taken by third-party planning entities that are located in other jurisdictions. Additionally, since Washington and California markets are also carbon-constrained due to the Clean Energy Transformation Act and Senate Bill 100,[9] respectively, PGE would need to forecast future emissions requirements and policy direction from the Washington Department of Ecology and California Air Resources Board, which the company is not able to do.[10] PGE would be open to supporting an effort to do a regional study.

DEQ coordination of emissions assumptions – Staff recommendation

> Utilities should include a table that lists the emissions assumptions for each existing and proxy resource modeled in the IRP, developed in partnership with DEQ.

PGE response

PGE plans to work with DEQ to ensure that PGE uses emissions assumptions in resource modeling that are aligned with the emissions reporting methodology used in DEQ's Greenhouse Gas Reporting Program under ORS 468A.280. PGE is willing to provide a table that presents these emissions assumptions. Commission guidance is, therefore, not necessary and would be redundant.

GHG emissions graph – Staff recommendation

> Utilities should include in the CEP a graph of portfolio GHG emissions by year for the preferred portfolio, important sensitivities, and each scenario in Chapter 1 of this straw proposal.

[9] See https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201720180SB100
[10] Washington's CETA can be found at https://www.commerce.wa.gov/growing-the-economy/energy/ceta/ and California's Senate Bill 100 can be found at https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201720180SB100.

PGE response

PGE appreciates Staff's recommendation on how it would like to see annual GHG emissions reported in its CEP, and we will take this into consideration when writing our CEP. However, PGE is concerned that it is overly prescriptive to have guidance that dictates which graphs are included in the CEP, though we appreciate Staff's desire for consistency of information between utilities.

Staff questions for workshop

Staff question #1

> Is there a simplified way to convey the impacts on regional emissions that is still useful to stakeholders?

PGE response

PGE is not the best entity to model the geographic and distributional impact of greenhouse gas emissions across Oregon. PGE believes that regional greenhouse gas emissions analysis is best performed by or on behalf of the public agencies that collect and analyze this data. This includes the Oregon Department of Environmental Quality, Oregon Department of Energy, Washington Department of Ecology, and California Air Resources Board.

Staff question #2

> Is it more useful to see how the regional emissions change over time or compare regional emissions between different portfolios?

PGE response

Once identified by an entity such as DEQ, PGE can employ our capabilities and investments to assist communities with their clean energy journey as outlined in HB 2021. Furthermore, HB 2021 is based on our annual in-state emissions reporting and not hourly emissions. PGE does not currently track GHG emissions on an hourly basis, nor does the region track carbon intensity by hour for power transacted in unspecified capacity in markets.

Topic #2. Renewable Energy Credits (RECs)

REC generated and acquired – Staff recommendation

> In the IRP, utilities should report the expected number of RECs to that will be generated or acquired by the utility for all existing and projected resources in the preferred portfolio. Utilities should specify the RECs that will be retired on behalf of the utility/all customers, retired on behalf of voluntary customers, banked, or sold or otherwise transferred to customers in another state or an entity that is not captured by the previous list.

PGE response

The CEP is an emissions-based target, not a REC target. The law requires that generation has the emission attributes of the resource itself, ORS 469A.430, and the generation emission calculation is unaffected by the existence or lack of RECs. DEQ does not require utilities to report emissions for electricity generated where RECs are unbundled, because it is tracking emissions, not RECs. The absence of emissions associated with a generating resource like wind or solar for GHG accounting and reporting purposes is distinct from any renewable energy claims that may or may not be made on that resource. This is a long-established premise of Oregon's GHG reporting program at DEQ.

Oregon-allocated RECs – Staff recommendation

> Utilities should report this for each year for the Preferred Portfolio (for Oregon-allocated RECs).

PGE response

PGE plans to follow standard IRP procedure to report the number of RECs within the Preferred Portfolio, including the number and type of RECs generated and retired as well as the size of its REC bank. However, as RECs are not used for meeting HB 2021's emission reduction targets, PGE does not believe additional REC annual reporting requirements are warranted.

Topic #3. Fossil fuel resource operations

Fossil resource generation and average heat rate – Staff recommendation

> Utilities should report total annual generation and average heat rate for each fossil resource, explaining any impacts on generation and heat rate of operational changes and/or emissions constraints.

PGE response

PGE appreciates Staff's request on how to report fossil resource generation and the impacts of emission constraints on plant operations on a planning basis. PGE intends to impose constraints on the IRP models such that our planned emissions in 2030 and 2035 do not exceed our clean energy targets. The constraints would be on total GHG emissions rather than on individual plants. This allows the models to meet the clean energy targets at least cost/least risk to our customers.

3 years of historical generation and average heat rate graph – Staff recommendation

> Utilities should provide graphs in the CEP with 3 years of historical generation and average heat rate data for its fossil fuel resources.

PGE response

PGE finds this recommendation to be duplicative of existing utility requirements. This information is available in PGE's Federal Energy Regulatory Commission (FERC) Form 1.[11] PGE is also required to annually report the total GHG emissions from thermal plant operations to DEQ, by facility. DEQ makes that data available on its website.

Staff question for workshop:

> If there are confidentiality issues with this level of detail, please explain. And, would it be meaningful enough to stakeholders if the utility reports this projected data on an aggregate level by fuel type?

---

[11] See link for PGE's 2021 FERC Form 1.
https://elibrary.ferc.gov/eLibrary/filedownload?fileid=642171C6-AA6C-CBC4-920C-806212D00000

PGE response

As mentioned above, historical generation and average heat rate for PGE's fossil fuel resources is publicly available in FERC Form 1.

Topic #4. Data Standardization and Accessibility

Website – Staff recommendation

> Staff, utilities, and all interested stakeholders should collaboratively develop by February 1, 2023 an agreed upon approach to capturing standardized information and data related to their CEP and how they will make it publicly available in a similar fashion on their websites.

PGE response

PGE agrees with Staff's recommendation for accessible standardized information and data related to the CEP and HB 2021. To this end, PGE is currently developing a website for its CEP as well as creating "learning labs" for community partners to learn and engage on PGE's CEP.

PGE sees an opportunity for Staff to collaborate across the DSP, IRP and CEP on creating data standardization and accessibility. Staff is already required to "prepare accessible, non-technical educational materials" needed to "support public engagement" in "consultation with utilities and stakeholders" as part of UM 2005. Having a consistent approach in the CEP would be useful to new stakeholders, as well as utilities.

Readability – Staff recommendation

> The IRP/CEP, or a designated section that contains all of the information required by HB 2021, should be written for an introductory audience and include definitions of all key terms.

PGE response

PGE appreciates Staff's recommendation to write its IRP/CEP for an introductory audience. PGE strives to make its IRP/CEP complete and accessible to stakeholders and interested parties. Staff's recommendation is a good reminder to work to minimize industry jargon, define all acronyms, and simplify language to the extent possible.

Staff questions for workshop

Staff question #1

> Who can facilitate this process? Does it need to be done separately for each utility?

PGE response

PGE recommends that these workshops be facilitated by the OPUC through a third-party community-based organization facilitator.

Staff question #2

> What are parties' preferred processes for addressing issues related to the designation of confidential information?

PGE response

PGE believes the existing process to designate confidential and highly confidential information through general and modified protective orders should be adequate to protect commercially sensitive information while enabling an appropriate level of public transparency.

Conclusion

The CEP may present the new findings from analytical planning processes through the lens of Oregon's rapidly changing and decarbonized energy future, with a focus on reliable, affordable, and equitable outcomes. Through the CEP, PGE is working to further clarify the timing and intersections between the DSP, IRP, and CEP. A key focus will continue to be the improvement of opportunities for community engagement and accessibility, including coordination across dockets to reduce workload wherever possible. The result of these proceedings must meaningfully reflect stakeholder and community input.

PGE is committed to decarbonizing, accelerating the adoption of DERs, as well as creating a holistic and transparent approach to meeting our greenhouse targets. This requires a learning mindset, which means we are curious and willing to listen and see things in different ways. It is not enough to simply gather the information; we must integrate new voices into our decision-making processes. Doing so builds trust and enables meaningful collaboration. Engaging with our customers and communities in this way will help us move closer to our goal of an equitable energy future for all. We look forward to working with OPUC Staff, stakeholders, and partners on the development of the CBIAG and the CEP.