# Summary of written feedback from PGE's 2019 Integrated Resource Planning Public Process

Date posted: 7/24/2019

Throughout the public process to support the development of the 2019 IRP, PGE invited stakeholders to submit comments, questions, and other feedback to the IRP team. PGE greatly appreciates the effort that stakeholders put into our public process to improve the development of our plan. This document provides a summary of the key topics that were raised through written feedback and PGE's responses to that feedback. Attachment A at the end of this document includes the full comments received from stakeholders.

# Feedback on External Studies

Торіс	Summary of Feedback Received	Response
Energy Efficiency Forecast	In comments responding to the Draft 2019 IRP, OPUC Staff indicated an interest in further discussion about the assumptions underlying the energy efficiency forecasts, including the decline in energy efficiency (EE) acquisitions over time and the increase in cost.	The reference energy efficiency (EE) forecast of savings and cost are based on information provided by Energy Trust of Oregon. Energy Trust provided a methodology report that is included in External Study B. Energy Trust of Oregon Methodology. The reference and high EE scenarios are discussed in the 2019 IRP in Section 4.1.2 Energy Efficiency. PGE looks forward to additional discussions about energy efficiency forecast assumptions.
Market Capacity Study	National Grid and Rye Development provided several recommendations for the market capacity study, including the consideration of economics, scenarios for growth of California renewable resources, and the potential expansion of the EIM.	PGE hired Energy and Environmental Economics (E3) to prepare a study of regional capacity and to provide low, reference, and high recommendations for the market capacity assumptions for PGE's capacity adequacy assessment. A discussion of the study is provided in Section 2.4.2.1 Market Capacity Study of the 2019 IRP and E3's report is provided in External Study E. Market Capacity Study.
Decarbonization Study	The City of Portland suggested that PGE consider decarbonization scenarios as sensitivities within the IRP to investigate whether near-term actions would be consistent with long-term needs under such scenarios. The City of Portland also urged PGE to incorporate a more rigorous forecast of electric vehicle (EV) adoption within the IRP.	PGE incorporated a Decarbonization Scenario based on the High Electrification pathway in the Decarbonization Study into the IRP. Information on this scenario can be found in Section 7.4.1 Decarbonization Scenario. In addition, PGE included EV adoption within the scope of the DER Study in order to capture the effects of non-linear adoption of EVs on future loads and demand response potential and to characterize uncertainties. More information can be found in Section 4.1.3.1 Electric Vehicles.

Торіс	Summary of Feedback Received	Response
Decarbonization Study	Northwest Natural requested additional data from the Decarbonization Study, suggested that the Decarbonization Study should be used to inform sensitivities, and urged PGE not to compare cross-sectoral costs within PGE's IRP.	PGE provided additional public data that was requested from the Decarbonization Study on the IRP website and did not incorporate cross-sectoral cost impacts from the Decarbonization Study in the IRP. The full Decarbonization Study report can be found in External Study A. Deep Decarbonization Study in the 2019 IRP.
Customer Insights Study	OPUC Staff expressed concern over the extent to which our Customer Insights Survey influenced portfolio construction, scoring metrics, and the Action Plan. Staff also requested information on the survey methodology, particularly, "if random sampling was used and if PGE considered whether using an online web survey could unintentionally exclude some customers from participating."	PGE considered the results of the Customer Insights Study as informative but not directive as we designed the non-traditional scoring metrics. The samples for Customer Insights Survey were drawn randomly from PGE's residential and business customer database. To account for potential factors related to online survey response rates, the residential sample group was weighted by gender, age, county, and PGE residential customer segments. Business customer responses were weighted by revenue segment. The Customer Insights Study can be found on PGE's IRP website: <u>https://www.portlandgeneral.com/-/media/public/our-company/energy- strategy/documents/msi-customer-insights-study-rt-18-1-2018-02-14.pdf</u>
DER Study	ODOE expressed interest in understanding Navigant's input assumptions for EV adoption and infrastructure development in the DER Study. Emphasis was focused on the rate of public charging station development, and logistical limitations to industrial storage applications.	Responses were provided to ODOE incorporating additional information from Navigant. The DER Study report can be found in External Study C. Distributed Energy Resource Study in the 2019 IRP.

# Feedback on Futures and Uncertainties

Торіс	Summary of Feedback Received	Response
Carbon Prices	OPUC Staff requested clarification on the application of the same carbon pricing forecasts to Oregon, Washington, and California for IRP modeling; asserting that state programs are not likely to be linked, but to each maintain individual targets.	In the 2019 IRP analysis, the assumption of linked state programs is equivalent to an assumption that compliance instruments can be traded between covered entities in different states. This can result in a single clearing price regardless of whether the two states have similar or different greenhouse gas caps.
Natural Gas Prices	RNW suggested that the low natural gas price of approximately \$4/MMBtu (nominal) in 2050 seemed unlikely. NWEC expressed interest in testing a high gas price forecast, which would exceed the high natural gas price future used in the 2019 IRP.	PGE discussed natural gas price assumptions at Roundtable 18-2 and 18-3 and the Low, Reference, and High Natural Gas Price assumptions are described in Section 3.2.1 Natural Gas.
Hydro Assumptions	OPUC Staff expressed concern that the hydro projections for the 2019 IRP did not reflect changing climate patterns.	PGE investigated the potential impacts of climate change on streamflow patterns for the PNW hydro system as part of the 2016 IRP. The study results can be found in Appendix E. Climate Change Projections in Portland General Electric Service Territory in the 2016 IRP.
WECC-wide Renewables	RNW expressed interest in "futures that would look at WECC-wide (renewable energy buildout) high and across the different capital cost, CO2, gas, and need conditions."	PGE presented the results of varied scenarios of the High WECC Renewable Buildout Future, consistent with RNW's request, at Roundtable 18-3. Additional information can be found in Section 3.2.3 High Renewable WECC Buildout.
WECC-wide Renewables	NWEC requested clarification on the source of the WECC database used in the Aurora model. Specifically, if the database stems from the WECC Anchor Data Set or another source.	The WECC-wide database used to produce hourly price forecasts was developed by Wood Mackenzie. PGE made modifications to the database to update natural gas prices and carbon prices. For the High Renewable WECC market price futures, PGE also modified resource additions and coal resources.

# Feedback on Needs Assessment

Торіс	Summary of Feedback Received	Response
Load Forecast	In response to the Draft 2019 IRP, CUB provided several comments and questions regarding the load forecast, including the choice of economic drivers, the industrial load forecast, and the calculations for the base load forecast.	Many of CUB's comments on the Draft 2019 IRP were addressed in PGE's responses to CUB Data Requests No. 001 through 006 in the IRP Docket (LC 73). The load forecast is discussed in Section 5.1 of the 2019 IRP and additional details are provided in Appendix D. Load Forecast Methodology.
RPS Need	NWEC expressed support for the approach of considering physical RPS compliance in long-term planning as well as "a structured and periodic approach to new resource acquisition."	PGE provides information on the renewable glide path associated with the preferred portfolio in Section 7.3.2 Contribution to Meeting Needs.
RPS Need	OPUC Staff requested that PGE provide additional information about RECs from QFs and the RPS compliance implications of PGE's REC bank.	PGE provides the forecast of REC production from QFs that are included in the RPS needs assessment and portfolio analysis in Appendix G. Load Resource Balance (Section G.4 REC Production and Obligation by Need Future). In Section 4.5 RPS Need, PGE states that "in the Reference Case a strategy of compliance through REC bank depletion could meet RPS obligations through 2035."

# Feedback on Resource Options

Торіс	Summary of Feedback Received	Response
Storage Assumptions	National Grid, Rye Development, Gridflex Energy, Absaroka Energy, Orion Renewables, and Ecosystem Research Group LLC made several suggestions related to energy storage modeling. In particular, it was requested that PGE utilize cost and performance estimates from developers for specific proposed pumped storage projects, that pumped storage be modeled in increments smaller than the full project size to account for potential multi-party agreements, and that pumped storage be modeled with a lifetime of 50 years.	In response to stakeholder input, PGE's portfolio analysis allowed pumped hydro addition sizes down to 100 MW to account for the potential for multi-party agreements on a single pumped storage facility. Consistent with past practices, PGE did not incorporate cost or performance information that was shared with the company from developers in the IRP analysis. Cost and performance assumptions for resources in the IRP can be found in External Study D. Characterizations of Supply Side Options.
Storage Assumptions	Stakeholders requested that PGE fully evaluate the capacity and flexibility benefits of pumped storage versus battery resources with a focus on the impacts of duration, that PGE test an 8-hour battery system, and that PGE test a sensitivity in which standalone storage resources qualify for the federal Investment Tax Credit.	PGE evaluated pumped storage and battery systems on a consistent basis throughout the IRP (see Chapter 6. Resource Economics) and responded to stakeholder requests by allowing pumped storage addition sizes down to 100 MW to account for the potential for multi-party agreements on a single pumped storage facility. PGE did not test an 8-hour battery system or investigate the potential impacts of an ITC for standalone storage.
Storage Assumptions	Orion Renewables and Absaroka Energy asked that PGE conduct a high battery cost sensitivity.	In addition to the Reference Case, PGE analyzed low and high battery technology cost scenarios in the 2019 IRP. Technology cost trajectories are discussed in Section 3.3 Technology Cost Uncertainty and resource economics are discussed in Chapter 6. Resource Economics.
Wind Assumptions	NWEC, Orion Renewables, and Absaroka Energy expressed concern regarding the capacity factor assumptions for wind resources in the 2019 IRP, in particular, for Gorge Wind and Southeast Washington Wind. Staff, Orion Renewables, and Absaroka Energy asked that the IRP include wind capacity factor sensitivities.	In response to requests from stakeholders, PGE prepared a wind capacity factor sensitivity that is included in Section 6.5 Capacity Factor Sensitivities. This analysis investigates a range of potential capacity factors for Pacific Northwest Wind and investigates resource performance relative to the generic Montana Wind resource.

Торіс	Summary of Feedback Received	Response
Solar Assumptions	NWEC advocated for further study of future declines in capital cost estimates for solar resources and requested further analysis to investigate differences in cost estimates.	PGE was provided cost estimates for solar resources by third party consultant, HDR, Inc. for the 2019 IRP. PGE addressed uncertainty in the forecast of solar resource technology costs in Section 3.3 Technology Cost Uncertainties and incorporated low and high solar cost trajectories in the resource and portfolio analysis.
Transmission	Early in the IRP process, some stakeholders submitted feedback seeking to learn more about the treatment of transmission in the IRP.	PGE held a public IRP stakeholder meeting which focused discussion on transmission on December 19th, 2018.
Transmission	Multiple stakeholders provided input on the IRP's treatment of transmission. For example, both National Grid/Rye Development and RNW/NWEC provided detailed steps to incorporate transmission and evaluate curtailment risk in the 2019 IRP. RNW and OPUC Staff expressed a desire for the IRP to model conditional-firm transmission in IRP analysis.	PGE outlined the current approach towards operating in the PNW transmission system, transmission planning, available transmission products, and transmission considerations within the IRP in Section 5.5 Pacific Northwest Transmission System.
Transmission	RNW submitted the recommendation that the proposed RFP allow bids to have conditional-firm transmission products, and that future RFPs align with BPA's study process.	As described in Section 8.3 Renewable Actions, PGE continues to consider transmission requirements for the proposed renewable action and plans to provide a proposal within Docket No. LC 73.
Flexibility Analysis	National Grid and Rye Development expressed support for inclusion of pumped storage as a resource in the flexibility value analysis and the inclusion of flexibility value as an input into ROSE- E. They suggested that PGE simulate multiple years with increasing renewable obligations.	PGE included pumped storage as a resource in the flexibility value analysis and incorporated its use into portfolio analysis. See Chapter 6. Resource Economics and Chapter 7. Portfolio Analysis. Due to the computational complexity of flexibility analysis, PGE's analysis focused on the year 2025 only.
Flexibility Analysis	RNW expressed concern that a flexibility value was not provided for solar plus storage and renewable resources, and urged PGE to include a flexibility value for solar plus storage.	PGE did not model flexibility value or integration costs for solar plus storage. The ability of renewables to provide value to the system through curtailment is captured in the integration cost estimates in Section 6.1.3.

Торіс	Summary of Feedback Received	Response
Integration Costs	Stakeholders expressed concern that the solar integration cost in the 2019 IRP is higher than the renewable integration cost in the 2016 IRP. RNW and NWEC presented concerns about the use of a linear scaling of a single solar resource as input data. Stakeholders suggested that PGE modify modeling methodology to include a broader data set. RNW and NWEC additionally requested that PGE explore in detail integration cost methodology and drivers for solar integration cost increase and present more detailed information for understanding the solar integration cost.	PGE would like to clarify that the scaled solar data is composed of three sites in Central OR aggregated into one shape for input. In new variable energy resources (VER) integration costs detailed in Section 6.1.3, 100 MWa of each new VER is added in contrast to the 2016 IRP in which varying amounts of VERs were added in each run. PGE greatly appreciates the engagement and discussion surrounding integration cost estimates for new VERs from RNW and NWEC and will continue to investigate the drivers behind the solar integration cost.

# Feedback on Portfolio Analysis

Торіс	Summary of Feedback Received	Response
Portfolio Construction	National Grid and Rye Development requested portfolios that add no new thermal resources, limited thermal resources, a portfolio focused on pumped storage, a portfolio that includes the Swan Lake pumped storage project, and portfolios that compare with and without pumped storage. National Grid and Rye Development also requested portfolios that add pumped storage in increments over time and portfolio that incorporates 8-hour batteries. National Grid and Rye Development also urged PGE to allow all capacity resources to meet remaining needs when testing renewable resources.	PGE included in the portfolio analysis multiple portfolios that exclude thermal resource additions and multiple portfolios that include pumped storage. The dispatchable capacity portfolios provide for a direct comparison of pumped storage versus other technologies as the primary capacity resources. PGE did not model the Swan Lake pumped storage project or a portfolio with 8-hour batteries. The final renewable resource portfolios constrained capacity additions to 6-hour batteries for comparability. More information can be found in Section 7.1 Portfolio Construction.
Portfolio Construction	ODOE requested two portfolios with specified objective functions, technology future weights, and resource constraints.	PGE tested the requested portfolios and presented the draft results at Roundtable 18-5. One of the portfolios yielded resource additions that were very similar to other optimized portfolios and the other portfolio yielded very poor cost outcomes relative to other scored portfolios. These portfolios were not carried into the final analysis.
Portfolio Construction	RNW requested that PGE design portfolios that optimize on both cost and GHG emissions, and portfolios that test solar plus storage, wind plus storage, slices of pumped storage hydro, and that exclude thermal resources.	PGE included an optimized portfolio with an objective function that balances both cost and GHG emissions. Among the renewable resource portfolios, PGE tested a portfolio with solar plus storage, but did not test a portfolio with wind plus storage. PGE allowed pumped storage additions down to 100 MW and tested multiple portfolios with pumped storage. PGE tested multiple portfolios that excluded thermal resources.
Portfolio Construction	Absaroka Energy requested additional sensitivities that tested different cost and performance assumptions for energy storage.	PGE did not conduct these sensitivities. PGE did examine energy storage performance across many wholesale market price conditions. Energy storage resource economics is discussed in the 2019 IRP in Chapter 6. Resource Economics.
Portfolio Construction	OPUC Staff requested additional information about planning horizon, acquisition constraints, and other portfolio construction assumptions when providing feedback on PGE's draft Action Plan.	PGE provided additional information about portfolio construction assumptions in the Draft 2019 IRP and the filed 2019 IRP. See Section 7.1 Portfolio Construction.

Торіс	Summary of Feedback Received	Response
Portfolio Scoring	OPUC Staff expressed concern about whether the near-term cost metric might favor near-term purchases and limit future optionality.	The portfolios screened out due to poor performance with respect to the near-term cost metric are shown in Figure 7-8 in Section 7.2.2 Portfolio Scoring.
Portfolio Scoring	RNW requested additional information on how screens would be applied in scoring, urged PGE to use the average NPVRR across futures as the cost metric, and the variance or standard deviation as the risk metric, and expressed support for comparing portfolios across a broader set of metrics.	PGE further discussed the screening process at Roundtable 18-6 and Roundtable 19-1. PGE selected the Reference Case NPVRR as the primary cost metric and the semi- deviation as the variability metric. Additional information can be found in Section 7.2 Portfolio Performance.
Portfolio Scoring	National Grid and Rye Development requested more information on whether carbon prices were reflected in the cost metric, why pumped storage portfolios had higher risk scores than battery portfolios, and why SCCT portfolios performed better than storage portfolios on GHGs.	PGE provides this clarifying information: the impacts of carbon pricing are reflected in the cost metric; in the final evaluation, the pumped storage portfolio had a very similar risk score to the battery portfolios; and the GHG emissions were very similar between the SCCT and the battery portfolios. See Section 7.2.2 Portfolio Scoring for additional information.
Portfolio Scoring	National Grid and Rye Development also questioned whether the evaluation included the value of subhourly flexibility for pumped storage, value after 2050, the impacts of SB 100 in California, and an enhanced day-ahead market (EDAM).	PGE accounted for subhourly flexibility for all dispatchable resources, including pumped storage, in the flexibility value, which was included in the portfolio analysis. See Section 6.2.2. Flexibility Value. PGE tested the potential impacts of new clean energy policies like SB 100 with the High Renewable WECC market price futures. See Section 3.2.3. High Renewable WECC Buildout. PGE did not evaluate the potential impacts of new markets, such as an EDAM.
Portfolio Scoring	National Grid and Rye Development expressed concern with screening out portfolios based on the near-term cost metric, and suggested that if PGE utilizes the near term cost screen, it should model resource cost structures as fixed price with escalation at inflation. National Grid and Rye Development also suggested a screen related to transmission access.	PGE clarifies that fixed costs for new resources in the IRP are modeled as a fixed price with escalation at inflation over time. Variable costs in each year reflect simulated dispatch in that year. See Section 6.1 Resource Costs for more information. PGE did not apply transmission-related screens in portfolio analysis.

# Feedback on the Action Plan

Торіс	Summary of Feedback Received	Response
Relation to Preferred Portfolio	In comments responding to the draft Action Plan presented at Roundtable 19-1, Staff requested additional information on how the Action Plan relates to the preferred portfolio and questioned the inclusion of resources in the preferred portfolio that may not be available in the market.	PGE included additional information on how the preferred portfolio was designed and how it relates to the Action Plan in the Draft 2019 IRP and the filed 2019 IRP. See Section 7.3 Preferred Portfolio and Section 8.1 Key Elements of the Preferred Portfolio.
Relation to Preferred Portfolio	NWEC generally agreed with the design of the preferred portfolio around a set of actions, rather than prescriptive resources and with the preferred portfolio design principles. NWEC considered the Action Plan a "starting point" and suggested that PGE devote more attention to assessing large scale batteries and flexible demand side strategies.	PGE has not made substantive revisions to the Action Plan between the draft and filed 2019 IRP, but the Company looks forward to continuing to discuss the Action Plan within Docket No. LC 73.
Customer Actions	Staff expressed support for the customer actions included in PGE's Draft Action Plan presented at Roundtable 19-1.	PGE retained these actions in the final IRP, however did update the energy efficiency number cited within the Action Plan to correct for a reporting error that was presented with the draft Action Plan at Roundtable 19-1.
Renewable Action	Staff expressed concern about the renewable action presented as part of the Draft Action Plan at Roundtable 19-1 and urged PGE to provide additional information to support this action.	PGE provided additional information about the renewable action, including its contribution to meeting near-term needs and potential cost impacts in Section 7.3.1 Preferred Portfolio Performance.
Renewable Action	In comments responding to the Draft 2019 IRP, AWEC expressed concern regarding the need for and feasibility of additional renewables and the potential impacts to QF prices of an acknowledged renewable action.	To provide additional insight on the near-term impacts of the renewable action, PGE provided information about near-term cost impacts in Section 7.3.1 Preferred Portfolio Performance and the contribution to near-term needs in Section 7.3.2 Contribution to Meeting Needs. PGE appreciates the concern raised by AWEC that the current methodology for pricing QF contracts leads to adverse outcomes for customers. PGE will continue to advocate for QF pricing methodologies that ensure that customers are not adversely affected by PURPA obligations in current and future PURPA-related dockets at the Commission.

Торіс	Summary of Feedback Received	Response
Capacity Action	Staff urged PGE to provide additional information about the drivers of capacity needs and plans to pursue bilateral contracts.	Information about capacity needs and the drivers of those needs can be found in Section 4.3 Capacity Adequacy. PGE included Action 3B in the Action Plan to update the Commission and stakeholders on the status of PGE's bilateral negotiations. See Section 8.4 Capacity Actions.
Capacity Action	AWEC suggested that capacity needs could be partially met through long-term direct access and questioned whether PGE might meet a portion of capacity needs through market power.	PGE discusses our position related to reliability and direct access in Section 2.2.2 State Policies and in Section 4.7.3 Direct Access and Resource Adequacy and further addresses this topic in PGE Advice No. 19-02. With regard to market power, PGE includes low, reference, and high market capacity assumptions in our capacity adequacy assessment based on a market capacity study which does not constrain availability based on transmission within the Pacific Northwest. The market capacity study is discussed in Section 2.4.2.1 Market Capacity and the study is included in External Study E. Market Capacity Study.
Capacity Action	National Grid/Rye Development and Staff both commented on the staged nature of the capacity action. National Grid suggested that a staged process may create an unfair advantage for existing resources and urged PGE to consider an all source RFP in 2020. Staff questioned whether the staged process would allow for full consideration of new resources, like pumped storage.	PGE has not made substantive revisions to the Capacity Action between the draft and filed 2019 IRP, but the Company looks forward to continuing to discuss the Action Plan within Docket No. LC 73.
Capacity Action	RNW recommends that PGE's proposed Non- Emitting Capacity RFP allow for renewable resources paired with storage.	PGE's proposed non-emitting capacity RFP would allow renewable resources paired with storage. See Section 8.4 Capacity Actions for additional information.

# Feedback on Other Topics

Торіс	Summary of Feedback Received	Response
Procurement Activities	In comments responding to the Draft 2019 IRP, Staff observes that Appendix N is intended by PGE to meet Commission rules regarding the consideration of an RFP design within the IRP. Staff's comments call for additional RFP design detail within Appendix N specifically suggesting a more detailed non-price scoring rubric, an enumeration of RFP threshold requirements, and additional clarity on PGE's transmission requirements.	Note that in the filed 2019 IRP, the appendix labeled Appendix N in the Draft 2019 IRP was moved to Appendix J. PGE clarified language within Appendix J. Renewable RFP Design and Modeling Methodology to address Staff's concerns regarding PGE's threshold requirements specific to transmission. PGE's final IRP also includes a discussion of additional transmission considerations that PGE is applying in its effort to identify specific transmission requirements in a future renewable RFP process. PGE intends to deliver a specific proposal within the IRP process which we expect to ultimately be approved within the regulatory process associated with the RFP approval.
Procurement Activities	RNW requested additional clarity on whether the cost-effectiveness screen proposed for Action Plan related Renewable RFPs differs from the cost-effectiveness screen design that was employed in the 2018 RFP.	As noted in the Chapter 8. Action Plan, PGE's proposed renewable procurement design will include a cost-effectiveness screen similar to the 2018 Renewable RFP.
Procurement Activities	RNW encouraged PGE to clarify how flexibility benefits would be scored in an RFP for bids, including renewables and renewables plus storage.	PGE provides information related to the determination of flexibility value in RFP scoring in Section J.2.6 Determination of Flexibility Benefits in Appendix J.
Direct Access	Both NWEC and AWEC provided comments in response to the discussion of risks associated with long-term direct access loads in the Draft 2019 IRP. NWEC expressed a similar concern for the potential shifting of cost and risk between customers. AWEC suggested that "the most cost- effective solution appears to be for PGE to request to modify its curtailment policy to allow it to curtail long-term direct access customers first during a reliability event."	Risks associated with long-term direct access loads are discussed in Section 4.7.3 of the 2019 IRP. PGE looks forward to continued work with stakeholders to find a regulatory solution that shares the responsibility for resource adequacy and reliability across all customers.

Торіс	Summary of Feedback Received	Response
GHG Emissions	OPUC Staff requested that PGE include a section in the IRP that specifically addresses the GHG emissions forecast.	PGE's GHG emissions forecast can be found in Section 7.3.4 Greenhouse Gas Emissions.
Colstrip	During the public roundtable process, OPUC Staff and stakeholders requested that PGE provide analysis that investigates an exit of Colstrip from PGE's portfolio in 2027 and a sensitivity in which Colstrip is replaced with Montana Wind. Based on the information presented in the Draft 2019 IRP, NWEC suggested that PGE conduct an additional sensitivity investigating an exit date of 2025 and Staff suggested that PGE include an action in the Action Plan to investigate the impacts of depreciating Colstrip through 2027.	In response to stakeholder requests, PGE included analysis of two scenarios that contemplate an exit of Colstrip from PGE's portfolio at the end of 2027, one that included Montana Wind as a replacement resource. This analysis can be found in Section 7.4.2 Colstrip Sensitivities. This section also discusses some of the reasons that PGE did not include an action item related to Colstrip in the Action Plan. PGE is considering Staff's recommendation to include an action item related to Colstrip depreciation analysis in the Action Plan and looks forward to discussing this further within Docket No. LC 73.
Boardman Biomass	OPUC Staff requested information related to testing and analysis done by PGE to explore the potential use of biomass fuel as the feedstock for the Boardman coal plant.	Section 1.5.4 of the 2019 IRP provides a summary of the conclusions from biomass testing at Boardman.
Green Tariff	OPUC Staff requested that PGE share the number of customers and corresponding MWa of load that has subscribed to PGE's Green Energy Affinity Rider (GEAR).	PGE is providing this information in our response to OPUC Data Request No. 015 in LC 73.
Various	During PGE's public IRP process, PGE received comments from individual customers and citizens regarding a variety of topics including existing resources, new technologies, and grid reliability.	PGE greatly appreciates the direct feedback provided by individuals in the IRP process and reviews and considers all submissions received.

# Feedback on the Process and Transparency

Торіс	Summary of Feedback Received	Response
Stakeholder Comments	RNW requested that PGE post submitted comments and information about PGE's response to those comments.	This document includes the information requested by RNW.
Community Listening Session	Participants at the Community Listening Session made several suggestions about how PGE engages in the community. Specifically, participants suggested that members of the community and community-based organizations might have more interest in topics like the IRP if PGE works more proactively to attend their meetings, to develop relationships, and to provide more information about how PGE is engaging in the community or meeting community needs. Content related to the IRP had too much jargon and was not accessible for a non-energy audience. Community-based organizations are stretched thin and should not be expected to come to PGE's corporate headquarters to have a conversation.	PGE greatly appreciated the candid feedback about community engagement that we received at the Community Listening Session. The feedback extended beyond the IRP to include how PGE engages in the community and with community-based organizations. One of the key takeaways was that additional work is required to further develop relationships in the community and to identify the best way to work with community- based organizations before we can expect meaningful feedback on a topic like PGE's IRP. PGE is working to continuously improve our approach to community engagement to meet a broad set of customer and community needs.

August 4, 2017

Organization: Renewable Energy Coalition

IRP Topic(s) and /or agenda items: Treatment of QFs

Comment: My question is whether or not PGE assumes in its IRP that existing QFs who have PPAs renew those PPAs as they expire over the 20-year planning horizon. The usual pattern is to assume they do renew their contracts, but PacifiCorp has altered that assumption in their 2017 IRP, so I was wondering what PGE assumes. Thanks very much.

October 27, 2017

Organization: Willamette University

IRP Topic(s) and/or agenda item(s): Supply Side Resources

Comment: I am interested in understanding the reasons, if any, why PGE could not be carbon-free by 2035.

March 2, 2018

Organization: National Grid

IRP Topic(s) and/or agenda item(s): Scope of PGE's 2019 IRP

Comment: Attachment

#### Introduction:

National Grid USA ("National Grid") and Rye Development, LLC ("Rye") are proud to be involved with the development of the two most promising pumped storage projects in the Pacific Northwest, the Swan Lake North Project in southern Oregon ("Swan Lake"), and the Goldendale Energy Storage Project in southern Washington ("Goldendale"). National Grid and Rye are jointly developing these projects. Both projects will utilize environmentally-friendly "closed-loop" technology, are located near high voltage transmission corridors, and will each be able to provide unmatched flexibility as a resource, serving multiple roles, and providing stacked energy, capacity, and other reliability and economic benefits on a utility and/or regional basis.

## **General Comments:**

National Grid and Rye support Portland General Electric's ("PGE") plans, identified in its 2016 Integrated Resource Plan ("IRP"), to "expand energy storage modeling to incorporate pumped storage systems" (page 246) and to pursue "energy storage modeling, including differential ancillary services treatment for batteries versus pumped storage systems" (page 147). National Grid and Rye are encouraged by PGE's increasing attention to more granular modeling of pumped storage systems and recommend a rigorous consideration of pumped storage throughout PGE's next IRP. Furthermore, given that pumped storage is a much more mature technology than most other forms of energy storage, that it is deployable at significantly larger scales, and has a useful life of at least three or four times that of battery storage, National Grid and Rye request that pumped storage be considered as a separate resource. Lastly, given that the costs of pumped hydro facilities can vary significantly by site, and that sites are limited by geography and/or strategic locations on the high-voltage transmission system, National Grid and Rye encourage PGE to consider site-specific information from existing, under-development resources whenever possible in order to reduce the uncertainty in its analyses.

In addition to these general comments, National Grid and Rye provide the following comments on each of the topics identified by PGE in its IRP Roundtable 18-1 presentation, dated February 14, 2018.

## **Comments by IRP Topic:**

## Portfolio Construction

As PGE begins to construct the resource portfolios that will be included in its next IRP, National Grid and Rye request that PGE conduct a thorough analysis of the following portfolios:

- A portfolio representative of a case in which no new thermal resources are built;
- A portfolio representative of a case in which only limited thermal resource repowering is assumed;
- A pumped hydro portfolio that has a large pumped storage facility as an anchor resource, with other resource additions added to optimize the portfolio;
  - $\circ$   $\;$  This portfolio should include consideration of all of the following:

- The benefits a pumped storage resource can provide to a utility participating in the California Independent System Operator's Energy Imbalance Market ("EIM"),
- The ability of pumped storage to leverage existing transmission and rights and provide for a more optimized use of transmission facilities,
- The ability of pumped storage resources to provide energy arbitrage,
- The potential for enhancing and optimizing the deployment of current renewable facilities,
- "Portfolio effects" across PGE's generation fleet that would be provided by a pumped storage resource,
- Optimal set points of existing generation plants to minimize cycling and operations and maintenance costs,
- The fact that pumped storage resources are highly adaptive to many "use cases" over time and provide many essential grid services, given their unparalleled flexibility, and
- The long lifespan of a pumped storage asset.
- A portfolio that specifically models Swan Lake, given the lack of other attractive and mature pumped storage projects in the region; and
- A comparison case of including vs. excluding Swan Lake in each portfolio and sensitivity that PGE ultimately elects to run.

## Scenario Planning (referred to as "Futures and Uncertainties" in PGE's Presentation)

National Grid and Rye understand that the IRP process must consider numerous future potential scenarios and account for significant uncertainty. Although there is no perfect methodology for accounting for all potential uncertainty that may occur in the future, National Grid and Rye believe that PGE should, at minimum, consider the following scenarios and variables, as they represent possible (and potentially probable) ways the future might unfold:

- A more regionalized western energy market over the long-term and associated reductions in price volatility;
- Increased reliance on the EIM, inefficient spot markets without unit commitment, and increased volatility in the markets, which is likely to result in increased revenue for new pumped storage;
- Increasing environmental and operational constraints on the Northwest hydropower system, and greater variation in hydro years (*i.e.*, more extreme wet/dry years due to climate change, and fewer "normal" years);
- Low electric vehicle ("EV") adoption and potential interaction with/likely need for more storage to integrate renewables;
- Increased demand, further exacerbating the need for peaking resources, potentially coupled with increased EV adoption resulting in load increases and/or increased penetration of renewable generation facilities;
- High distributed energy resource ("DER") penetration with specific consideration of the probability that DERs will be available/serve as anticipated (*i.e.*, reliability likelihood);

- State of California passage of 100% RPS requirements, likely resulting in regional spillage of increased excess solar from California;
- Extreme political/social opposition to building new thermal resources, despite need for high flexibility;
- Battery cost declines level out or don't otherwise continue to decline at rates in line with historic trends, and high degradation, given high cycling rate (For example, higher costs for Lion, given supply constraints (including cobalt) and increased demand);
- Increasing demand for, and value placed on, flexible capacity, as compared to energy generation.

National Grid and Rye understand there are challenges and limitations to analyzing this wide range of scenarios and variables, but even if analyzed at a lower level of rigor than other IRP analyses, consideration of the above scenarios will still be valuable and informative for the IRP process because it will contribute an important understanding to the robustness of a resource under a highly uncertain future.

## Flexibility Assessments Methodology

National Grid and Rye recommend PGE's next IRP consider the limits and constraints of non-PGE-owned capacity available via contract (for example, environmental constraints for third-party-owned hydropower facilities). Similarly, PGE should consider the higher flexibility value of a PGE-owned pumped storage facility such as Swan Lake, which would not be subject to the same constraints on its utilization.

## Decarbonization Study

National Grid and Rye request that PGE incorporate up-to-date cost and technology specifications in its next IRP. Preferably, this information would be specific to sites under development in the region (*i.e.* Swan Lake). In any event, the 2016 IRP Black & Veatch study should be updated with information on current pricing from turbine manufacturers and capabilities of new variable-speed projects in operation and under construction globally.

For example, below are the pumped storage specs from the 2016 IRP that should be updated with current data from turbine vendors on new, variable-speed pumped storage projects. National Grid and Rye would be happy to facilitate the updating of this information using up-to-date specs from, for example, our industry partners (*e.g.,* General Electric).

- Minimum turndown capacity: 20%
- Ramp Rate: 100 MW/min
- Start time to full load: 2 min
- Scheduled maintenance: 2 wks/yr
- Equivalent forced outage rate: 1.7%
- EPC period: 60 months
- Overnight EPC capital cost for 300mw facility: \$700 million (2015 dollars)

- Owner's cost allowance 25%
- Overnight total capital cost: \$875 million
- o Overnight total capital cost standard deviation: \$218 million
- Fixed O&M costs: \$1,000 / MW-month
- Nonfuel variable O&M cost: \$0.40 / MWh
- Decommissioning cost: \$8.8 million
- Round Trip Efficiency: 77%

National Grid and Rye also recommend including a block of bulk 8-hour storage in the Low Electrification and High DER scenarios (as is done in the High Electrification scenario), given that there are strategically located pumped storage facilities under development in the region that are likely to be competitive resources, regardless of the degree of electrification or DER penetration.

## Market Study

National Grid and Rye are concerned that, according to PGE's Feb 14 workshop slides, "The market study will not provide insight into the economics of resources—it will simply estimate whether the resources are expected to be available." (slide 66) This approach is unlikely to result in useful information and overlooks basic economic principles. A market cannot be characterized by quantities alone. Whether a resource is available to PGE will depend on whether PGE is willing to pay more than other potential bidders (*i.e.*, whether the resource is of greater value to PGE's customers than it is to other potential purchasers). Thus, it is imperative that PGE consider the economics of resources as part of its market study.

Additionally, National Grid and Rye recommend inclusion and consideration in the market study of:

- Further aggressive growth of renewable generation in California. For example, California has already enacted a 50% Renewable Portfolio Standard, there has been a significant uptick in Power Purchase Agreements with Community Choice Aggregators and commercial and industrial customers, and pending California legislation that would further drive renewable generation growth.
- The EIM and its expanding footprint, and the potential for a Day-Ahead market.
- PGE's transmission access and Intertie rights.

As noted above regarding the Flexibility Assessments Methodology, National Grid and Rye recommend that the Market Study include consideration of the limits and constraints of non-PGE-owned capacity that is available to the company on the market, and consideration of the higher flexibility value from a potential PGE-owned pumped storage facility, which would not be subject to such constraints on its utilization.

Additionally, based on the current market outlook and likely future scenarios—including the likely probability that the region will be short of flexible capacity due to increased renewable penetrations, pressure from California for the EIM/Pacific Northwest to provide reliability services without any new capacity builds across the West Coast states, and significant retirements from the thermal fleet—

National Grid and Rye suggest that the Market Study should carefully consider and seek to understand these risks in order to inform decisions for the next IRP. In particular, these risks should be carefully considered to ensure PGE is pursuing the appropriate duration of new assets, as well as the appropriate resource mix of new capacity that will best protect ratepayers, while also ensuring its future resource mix is flexible enough to extract value, regardless of how future markets evolve or develop. To do so, PGE must consider highly-flexible resources like pumped storage.

## May 17, 2018

Organization: City of Portland Bureau of Planning and Sustainability

IRP Topic(s) and/or agenda item(s): Decarbonization study incorporated into 2019 IRP

Comment:

First, it seems obvious, but worth stating: Analysis should be done in this IRP cycle to incorporate the findings of the study into IRP efforts. Community stakeholders expect that the study will inform PGE's planning decisions, and not simply act as a standalone reference document.

It would be useful to conduct sensitivity analysis that incorporates potential public policy and the resulting electricity supply impacts into planning decisions. (This comment aligns with Angus Duncan's statement at the meeting yesterday) As we have already seen, both the City of Portland and Multnomah County have made their intentions clear through their respective 100% Renewable Energy by 2050 resolutions that there is an expectation from the communities that PGE serves to transition to carbon free electricity by 2035, and economy-wide decarbonization by 2050. Given the existing community resolutions, PGE should model a pathway to meet future demand with entirely carbon-free generation resources.

The decarbonization scenarios may be used as sensitivities in the planning process. A range of load levels and renewable requirements should be modeled in order to account for potential new/improved technologies that may emerge that could, for example, reduce load levels more so than existing technologies. Doing so would help manage expectations with stakeholders to understand a range of pricing scenarios.

The Decarbonization Scenarios (High Electrification, Low Electrification, High DER) should be used as a test to determine if near-term actions are consistent with long-term needs. When near-term actions do not align with the long term needs outlined in the study, it should be incumbent upon PGE to explain why actions that do not align with longer term needs are chosen.

The findings of the report show that all three scenarios can result in meeting 2050 goals. As such, the report should be used as motivation for improved treatment of new technologies. As an example, PGE should explicitly account for non-linear electric vehicle adoption forecasts.

June 15, 2018

Organization: NW Natural

IRP Topic(s) and/or agenda item(s): Decarbonization study incorporated into 2019 IRP

Comment:

NW Natural appreciates the opportunity to provide input into how Portland General Electric can make the best use of the insights in the Decarbonization Study in its IRP process.

As was discussed at Roundtable 18-2, NW Natural agrees that it should be used to help inform load forecast and renewable sensitivities for PGE's load and PGE's attendant costs. Exploring load forecast

uncertainties are a fundamental part of IRPs and enabling studies, such as the Decarbonization study, are helpful to inform important resource decisions.

Equally important, NW Natural does not believe this study should be used to compare societal costs of the entire Oregon energy system, which would essentially bring economy-wide energy policy discussions and analysis into PGE's resource planning process. NW Natural believes it would be better if the discussion and evaluation of these broader policy questions and societal costs involves expertise from parties in addition to PGE's (or any singly utility's) system planners and IRP stakeholders. NW Natural believes that these broader policy discussions regarding societal costs or environmental impacts should be addressed in a policymaking forum and outside of any individual utility's IRP process.

NW Natural appreciates the collaborative nature of an IRP and commends PGE for its willingness to solicit input from all stakeholder groups.

#### June 19, 2018

Organization: Renewable Northwest

IRP Topic(s) and/or agenda item(s): Scoring framework and scoring metrics

#### Comment:

Renewable Northwest thanks PGE for this opportunity to provide feedback as it develops a framework for portfolio scoring and the metrics that it would use to rank portfolios, and ultimately select a preferred portfolio, as part of the 2019 IRP process. We appreciate PGE's efforts to seek stakeholder feedback on these important topics.

#### Phase 1

Renewable Northwest encourages PGE to elaborate on what standards or thresholds it would use to screen out particular portfolios as part of Phase 1 of portfolio scoring in the 2019 IRP.

#### Cost

PGE is exploring what measure of cost to use to compare the relative performance of portfolios' cost and risk. At its May 16, 2018, roundtable, PGE presented two options: 1) NPVRR of Reference Case, and 2) Expected NPVRR. At the roundtable, some stakeholders advocated for the use of Expected NPVRR as it is a measure of costs that would capture NPVRR in all futures, arguing that using NPVRR of Reference Case would infer a weight on the Reference Case.

Renewable Northwest recognizes the complexity of determining what weight to assign particular futures for the purpose of estimating the Expected NPVRR. However, we encourage PGE to further explore the possibility of using Expected NPVRR for its comparison of the relative performance of portfolios' cost and risk.

#### Risk

PGE is exploring what measure of risk to use to compare the relative performance of portfolios' cost and risk. At its May 16, 2018, roundtable, PGE presented two options: 1) Semi-variance of NPVRR Above the Reference Case, and 2) Standard Deviation.

Renewable Northwest questions the use of Semi-variance of NPVRR Above the Reference Case in the 2019 IRP as a measure of risk in Phases 1 and 2 of portfolio scoring in the 2019 IRP. As Staff indicated in the context of the 2016 IRP:

[t]he use of this measure under weighs the possibility that a particular portfolio may result in lower than expected costs. . . . Staff cautions against discarding the information contained in the "better than expected" outcomes when constructing risk metrics. Staff maintains that using the variance or standard deviation is a more common and transparent method for characterizing the uncertainty contained within a distribution of data.<sup>[1]</sup>

Renewable Northwest encourages PGE to use either the variance or standard deviation in Phases 1 and 2 of portfolio scoring in the 2019 IRP.

[1]LC 66, Staff's Initial Comments at 30 (Jan. 24, 2017).

## Phase 2

Renewable Northwest appreciates PGE's efforts to incorporate stakeholder values by evaluating portfolios based on their performance across a wider arrange of metrics.

## Emissions

Renewable Northwest seeks to better understand PGE's proposal to rank portfolios based on their average annual emissions. As a result, we encourage PGE to elaborate on how the metric would work. Specifically, would PGE parse out CO<sub>2</sub>, SO<sub>x</sub>, and NO<sub>x</sub>emissions for a particular portfolio, and would the emissions be based on generation or cradle-to-grave (or both)?

Additionally, we encourage PGE to also incorporate fugitive CH<sub>4</sub> (methane) emissions.

#### Water Consumption

Renewable Northwest encourages PGE to provide greater detail on whether this metric seeks to capture average water consumption associated with generation, construction, or cradle-to-grave.

#### Variability

Consistent with our comments under Phase I, Risk, Renewable Northwest encourages PGE to use either the variance or standard deviation to measure variability in Phase 2.

#### Cost

Renewable Northwest encourages PGE to allow for additional comment on this proposed metric once we have a discussion about weighing of the short and long term metrics that PGE proposes.

#### Diversity and Reliability

Renewable Northwest encourages PGE to further elaborate on the methodologies it would propose to capture these values in scoring metrics.

#### June 20, 2018

Organization: Renewable Northwest

IRP Topic(s) and/or agenda item(s): Renewable Northwest's feedback on variables, conditions, and sensitivities

Comment: Renewable Northwest thanks PGE for this opportunity to provide feedback on its planned variables, conditions, and sensitivities, as part of the development of futures for the 2019 IRP process.

CO2Prices

Renewable Northwest echoes the NW Energy Coalition's verbal encouragement at the May 16, 2018, that PGE models a CO2with carbon prices that reflect the federal social cost of carbon.

#### PGE Need

Renewable Northwest encourages PGE to provide greater detail to help stakeholders understand how the different factors (i.e. QF completion and execution rates, distributed solar adoption, energy efficiency) that impact PGE has identified as impacting need would vary in PGE's low and high need cases.

#### **Capital Cost**

At a general level, Renewable Northwest encourages PGE to provide stakeholders greater detail on what would impact variation within the low, reference, and high capital cost conditions.

Renewable Northwest also encourages PGE to explore looking at the solar and storage capital costs as separate varaibles. If PGE determines that looking at storage and solar capital costs as separate variables is unfeasible, Renewable Northwest encourages PGE to provide greater details on how solar and storage capital cost assumptions change in the different cases (i.e. a low solar and storage future could be achieved by various permutations of solar and storage costs).

#### WECC-Wide High Renewables Test

Renewable Northwest encourages PGE to provide stakeholders greater detail on whether location matters in this model. If so, we encourage PGE to expand on whether the increased renewables would be assumed to be in the same geographical location as existing resources, or whether an assumption of greater geographic diversity would be explored. Finally, Renewable Northwest seeks greater clarity on whether the proportion of solar and wind resources would remain the same in PGE's planned high renewable test.

#### July 16, 2018

#### Organization: Renewable Northwest

IRP Topic(s) and/or agenda item(s): Stakeholder preference resource options scenario draft

#### Comment:

Renewable Northwest thanks PGE for this opportunity to provide feedback as the company seeks to develop a streamlined approach to collecting stakeholder input on portfolios to explore in the 2019 IRP process.

#### **General Comments**

Renewable Northwest encourages PGE to make available—either within the form or as an accompaniment— an explicit narrative explaining the different sections and how stakeholder input in a section would or could inform the process.

We also encourage PGE to identify what would be the default values or assumption in any section should stakeholders choose to leave anything blank.

#### **Objective Function**

Renewable Northwest seeks clarity on whether stakeholders could choose more than one objective function. If stakeholders are able to select more than one objective function, Renewable Northwest encourages PGE to clarify whether stakeholders can prioritize between objective functions.

Finally, we encourage PGE to explore including an objective function that focuses on greenhouse gas reduction, including CO₂ and so-called fugitive CH₄ emissions associated with natural gas extraction and transportation.

#### Technology, Need and Price Futures

We suggest that PGE include a narrative explaining that distributing the 100 points among the futures options is equivalent to assigning a weight to each of the futures. We also encourage PGE to clearly identify the default weights that would be assigned to the different futures.

For technology futures, we suggest that PGE makes available its resource costs assumptions prior to stakeholder submission of the form as this information will be important to stakeholders' ability to provide input into a weight distribution.

Finally, for Price Futures, Renewable Northwest seeks clarity on whether PGE intends to look at high, reference, and low "Hydro" price futures as opposed to "Market" price futures as it has done traditionally.

#### Annual Portfolio Constraints – RPS Procurement

Renewable Northwest is generally concerned about the concept of setting maximum annual "RPS Procurement" levels. This concept appears to undermine least cost/risk planning and to fit into a view of renewables energy resources that focuses on their RPS compliance value and that overlooks their energy and capacity value.

#### Annual Resource Constraints – Minimum Addition

Renewable Northwest commends PGE for trying to streamline efforts to collect stakeholder feedback on what specific portfolios the company to explore in its 2019 IRP. However, we are concerned about this section of the form asking stakeholders to specify "minimum additions" as it appears to be an unnecessarily confusing way for stakeholders to request assessment of a portfolio. We encourage PGE to instead allow stakeholders to simply select resources that they would like to see in a portfolio or not.

We also encourage PGE to differentiate between renewable energy resources when their geographic location has a significant impact in generation profile (i.e. include an option to request a portfolio that evaluates Montana wind).

August 15, 2018

Organization: Renewable Northwest

IRP Topic(s) and/or agenda item(s): Futures for the 2019 IRP process

Comment:

Renewable Northwest thanks PGE for this opportunity to provide feedback on futures for the 2019 IRP process.

Renewable Northwest is interested in futures that would look at WECC-wide RE high and across the different capital cost, CO2, gas, and need conditions. We are particularly interested in a future with WECC-wide RE high, low capital cost, high CO2, high gas, and high need, but consider that looking at other conditions for these variables/sensitivities would provide context for that future.

Renewable Northwest would also like to question PGE's low natural gas condition as \$4 for natural gas in 2050 appears unlikely.

We would also like to know more about the assumptions behind the different levels of Need and electrification of the transportation and heating sectors.

Finally, Renewable Northwest may provide additional feedback on these issues and those we have already commented on as PGE presents more detailed information (i.e. more information on capital costs assumptions, assumptions behind different levels of need, etc.) as part of the 2019 IRP process.

August 27, 2018

**Organization: OPUC** 

IRP Topic(s) and/or agenda item(s): Roundtable market price presentation hydro projections

Comment:

Just want to flag one concern raised briefly during the last IRP meeting: In Shauna's market price presentation, the hydro projections didn't reflect any change in output caused by changing climate patterns. This seems inconsistent with the load forecast, which forecast increasing summer and slightly lower winter peaks (graphics below). Let's talk more about this soon?

September 7, 2018

Organization: Orion Renewables and Absaroka Energy

IRP Topic(s) and/or agenda item(s): BPA transmission rights

Comment:

PGE's BPA transmission rights play a critical role in PGE's strategies for providing low-cost, reliable power to PGE's retail customers. Given that significance, I think it would be beneficial for PGE to share information about this topic with IRP Roundtable participants. For starters, it would be useful to present an inventory of these rights, current and future planned uses of these rights, and a discussion of the pros and cons of redirecting or repurposing some of these rights.

#### October 10, 2018

Organization: Renewable Northwest

IRP Topic(s) and/or agenda item(s): Portfolio request for PGE 2019 IRP

Comment:

Renewable Northwest thanks PGE for this opportunity to submit portfolio requests as part of the 2019 PGE IRP process. We respectfully request the following:

#### A portfolio that meets the two objective functions

Renewable Northwest acknowledges the added computational challenges associated with asking ROSE-E to design optimized portfolios that best meet the two objective functions currently available: minimizing the expected value of NPVRR across weighted futures and minimizing CO2 emissions. However, Renewable Northwest requests that PGE run ROSE-E in a manner set up to optimize for both of these two objective functions on the same run. Such run could provide PGE and stakeholders useful information on how PGE could achieve its decarbonization goals cost-effectively.

#### Renewables plus storage as a combined resource option

Renewable Northwest observes that current resource options do not appear to include projects that combine renewable energy resources like wind and solar with storage. If we are correct, we encourage PGE to include combined renewables and storage projects as resource options for this IRP. This would allow PGE to incorporate in its IRP analysis a resource combination that other utility IRPs in the region indicate has great value while allowing PGE's analysis to capture the value of the investment tax credit for storage. Finally, given the current state of the market, considering resources that combine renewables and storage appears key to the 2019 IRP's ability to comply with the OPUC's IRP Guideline 1(a).

In summary, Renewable Northwest recommends that PGE includes as resource options combinations of 1) wind and storage and 2) solar and storage. Additionally, Renewable Northwest encourages PGE to perform ROSE-E runs that allow the optimization tool to select these resources as soon as practicable.

#### Allowing ROSE-E to build portfolios that include slices of pumped storage projects

Renewable Northwest commends PGE for evaluating pumped storage as a resource option. However, we agree with stakeholder requests at the September 26, 2018 IRP roundtable that PGE also allow ROSE-E to select unit sizes below 400 MW. Specifically, we suggest that PGE enforces a minimum unit size of 100 MW to reflect the procurement or contracting of slice of a pumped storage project. PacifiCorp has signaled that it will follow that approach in its 2019 IRP.

#### Portfolios without thermal resources

Renewable Northwest respectfully requests that PGE run ROSE-E to design an optimized portfolio that only has as resource options: 1) renewable energy resources, 2) storage resources (battery and pumped), 3) resources that combine renewables and storage. Renewable Northwest strongly encourages PGE to run ROSE-E to meet "Minimize Exp[NPVRR]" but also a separate run where ROSE-E meets "Minimize Exp[NPVRR]" and "Minimize CO2 Emissions."

Finally, consistent with our request above, Renewable Northwest requests that these runs not enforce a minimum size for battery storage and that they enforce a minimum size of 100 MW for pumped storage.

#### October 10, 2018

Organization: Rye Development and National Grid Ventures

IRP Topic(s) and/or agenda item(s): Portfolio requests and comments to 2019 IRP draft portfolio analysis

Comment: Attachment

Rye Development

# national**grid**

October 10, 2018

Elaine Hart Manager-Integrated Resource Planning Portland General Electric 121 SW Salmon St. Portland, Oregon 97204

RE: Portfolio requests and comments in response to PGE's 2019 IRP DRAFT Portfolio Analysis

Ms. Hart and the PGE IRP Staff,

National Grid and Rye Development appreciate the opportunity to submit portfolio requests and provide comments in response to PGE's 2019 DRAFT Portfolio Analysis. We respectfully request the following portfolios:

**Proposed Portfolio A.** Pumped storage is added in increments to approximate PGE's growing capacity need and RPS obligations. For example, cumulative pumped storage: (a) 100 MW by 2025; (b) 200 MW by 2030; (c) 300 MW by 2035; and (d) 400 MW by 2040).

Minimum Cumulative MW	2022	2023	2024	2025	2030	2035	2040	2045	2050
Pumped Storage	0	0	0	100	100	100	100	100	100
Pumped Storage	0	0	0	200	200	200	200	200	200
Pumped Storage	0	0	0	100	200	300	400	400	400
Batteries (8hr)	0	0	0	200	200	200	200	200	200

**Proposed Portfolio B.** An additional dispatchable resource portfolio consisting of 8-hr batteries.

We recommend that for each of the portfolios that PGE evaluates, including the full slate of Dispatchable Resource Portfolios, that results are presented from both cost-optimized and GHG-optimized modeling runs.

# In addition to the proposed portfolios we appreciate the opportunity to offer the following comments:

#### Capacity Contribution of Energy Storage Resources

We encourage PGE to utilize a portfolio evaluation methodology where the system peaking capability (capacity value) of energy storage resources is based on the contribution of the resource during peak load conditions rather than a simple duration-based heuristic. For example, the "ELCC-based methodology" described in Section 8.5.1.4 of the 2016 IRP would more accurately value the contribution of increasing duration than a methodology where any storage resource with a duration greater than or equal to 4 hours receives a capacity contribution of 100%.

PGE's model may also not provide adequate capacity credit to storage resources to reflect the value that such resources provide based on their ability to shape their output to integrate renewables. Each of the Dispatchable Resource Portfolios includes the same amount of capacity (200 MW, subject to unit size constraints) to accompany 80 MW of wind.



Due to storage's ability to reduce renewable curtailment, thereby reducing the need for overbuilding renewables, a system with storage may not need as much wind capacity, i.e., portfolio D1-D4 could be overbuilt cases. We would encourage PGE when evaluating a combination of a dispatchable resource and a wind resource to ensure that the analysis captures all of the value streams of the dispatchable resource, including how it interacts with the wind resource in dispatch and the effects on capacity sizing.

This point especially comes into focus while looking at the near-term investments made currently in the optimal portfolio O1, which consists of storage and renewables. These two technologies are especially suited to go together for lower long-term costs relative to thermal options. So, their interactions (including sizing) should be considered while evaluating dispatchable resources' value.



## Flexibility Analysis

We support PGE conducting a Flexibility Analysis using the ROM model to quantify the "flexibility value" of dispatchable resources that may not be captured by AURORA (described in slides 11 through 19 of the July 11, 2019 IRP Roundtable Meeting). Energy storage could improve the operational flexibility of PGE's resource by: (a) avoiding renewable curtailment (i.e., charging during hours of negative net load); (b) providing various types of operating reserves (e.g., regulation reserves); (c) facilitating thermal resources to operate at more efficient operating points; and (d) generating (discharging) during scarcity events where the marginal system cost is very high. We recommend that PGE include pumped hydro storage in its Flexibility Analysis and use the "flexibility value" from the analysis as an input to ROSE-E. In addition, we recommend that PGE simulate multiple test years reflecting increasing renewable obligations (e.g., 50% RPS by 2040). For example, the 2016 IRP found that renewable oversupply increases from 3.3% at a 25% RPS to 18.0% at a 50% RPS (see Figure 5-20 of 2016 IRP).

## Inputs and portfolio assumptions

**PHS Minimum Unit Size** Draft Portfolio D4 presented at the September 26, 2018 Roundtable Meeting includes 400 MW of pumped storage and 80 MWa of wind by 2025. The quantity of pumped storage included in this portfolio exceeds the capacity need prior to 2025 (slide 35) and is based on the assumption that 400 MW is the minimum unit size that could be selected. We recommend that PGE reduce the minimum unit size of pumped storage in its modeling tools from 400 MW to 100 MW to reflect that PGE could realistically acquire smaller capacity slices.

**Costs** Pumped Storage costs appear to be at the higher end of the spectrum while batteries and gas units are at the lower end of the spectrum. Based on PGE's assumptions, modeled pumped storage (PS) has the highest overnight capital cost and FOM cost among all dispatchable resources and lowest efficiency across all storage options. Based on National Grid and Rye Development's preliminary engineering cost assessment, pumped storage installed costs would be close to those of a 6-hr L-I battery. In addition, it is unclear if PGE's analysis of overnight storage costs evaluates "cost per cycle" of the different technologies (total cost/number of possible cycles in each technology's asset life). We would encourage PGE to evaluate whether the overnight capital cost and FOM cost assumptions for batteries take into account the cycling effects.

	Сар	Fixed O&M Cost (2018\$/kW-yr)						
Resource Type	ROSE-E*	RESOLVE	LAZARD†	ROSE-E*		RESOLVE		LAZARD <sup>+</sup>
8hr Pumped storage	\$ 2,252	\$ 2,355	\$1,985-\$2,918	\$	11	\$	24	\$17-\$33
2hr L-I BESS	\$ 916	\$ 975	NA	\$	24	\$	18	NA
4hr L-I BESS	\$ 1,554	\$ 1,633	\$1,572-\$1,997	\$	31	\$	24	\$10-13
6hr L-I BESS	\$ 1,902	\$ 2,291	NA	\$	43	\$	30	NA
Biomass-wood	\$  5,935	\$ 5 <i>,</i> 892	NA	\$	111	\$	186	NA
Geothermal	\$ 6,216	\$ 5,063	\$4,084-\$6,534	\$	120	\$	200	NA
6×0 Wartsila Recips	\$ 1,265		\$664-\$1,123	\$	5		NA	\$15-\$20
1×0 GE LMS 100	\$ 1,154	\$ 1,250	-	\$	6	\$	12	NA
1×0 GE 7HA Frame Single Cycle	\$ 531	\$ 950	\$715-\$1,021	\$	2	\$	6	\$5-\$20
1×1 GE 7HA Frame Combined Cycle	\$ 906	\$ 1,300	\$715-\$1,327	\$	7	\$	10	\$6

 Table 1. Cost assumptions comparison across PGE's ROSE-E model, E3's RESOLVE model, and Lazard's latest levelized cost analysis

\* PGE costs are from <u>https://www.portlandgeneral.com/-/media/public/our-company/energy-</u> <u>strategy/documents/2018-10-05-pge-supply-side-option-summary.pdf?la=en</u>. FOM costs for pumped storage and batteries were initially reported in \$/kWh-yr.

*†* Lazard costs for pumped storage are based on its Levelized Cost of Storage (LCOS) version 2.0 (2016). Costs for batteries are based on its Levelized Cost of Storage (LCOS) version 3.0 (2017); costs for other resources are based on Levelized Cost of Energy Analysis version 11.0 (2017). All cost values have been adjusted to 2018\$ value assuming 2.10% inflation.

Overtime capital cost escalation of storage may not be considered through the modeling process. PGE's supply side options summary does not mention an escalated/de-escalated cost curve for storage systems (including batteries). For comparison, Lazard levelized cost of storage analysis projects a 7%~11% annual decline in L-I batteries capital costs over the period of 2016-2020.<sup>1</sup> E3's RESOLVE model assumes that capital cost of L-I batteries declines by 8.5% annually through 2023. Such escalation is assumed to flatten gradually afterwards and go down to around 1% in 2030.

It isn't clear whether and/or how costs associated with battery cycles (variable operation costs) are represented in the modeling. According to PGE's supply side option summary zero non-fuel variable costs are assumed for batteries in its IRP modeling process,<sup>2</sup> which seems to imply that if considered, a certain number of cycles per year have been assumed and such costs imbedded in the fixed costs. However, battery degradation cost increases as the system is cycled more frequently. Therefore, if batteries are mainly used to time shift renewable generation and provide energy, they should have variable costs tied to how they are dispatched. On the other hand, if batteries are built primarily for capacity, they would have limited ability to cycle and perform other services. Either way, more information is needed to understand what the battery cycle assumptions are and whether theses implications are considered in the modeling.

<sup>&</sup>lt;sup>1</sup> Lazard Levelized Cost of Storage, version 3.0, December 2017.

<sup>&</sup>lt;sup>2</sup> <u>https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/2018-10-05-pge-supply-side-option-summary.pdf?la=en</u>

## **Evaluation Process**

Evaluated futures are combinations of five carbon pricing streams, three gas pricing streams, and low and high hydro output scenarios.<sup>3</sup> Equal weighting was used to derive the evaluation metric results.<sup>4</sup>

## a. Cost metrics

It isn't clear if carbon pricing or carbon abatement costs are reflected in the cost metrics, especially in the reference cases. More details on this would be helpful.

## b. Economic risk metrics

It's not intuitive why pumped storage system would have greater cost variations (economic risk) across the futures than batteries. Especially given the maturity of the technology and local opportunities for such projects. We encourage PGE to provide more details on their economic risk assumptions.



## c. Environmental metrics

D6 (SCCT), which is a CT outperforms all the battery portfolios and renewable portfolios in GHG emissions. This is not intuitive. We would encourage PGE to provide more information on this.

<sup>&</sup>lt;sup>3</sup> Aug 22 Market price futures roundtable presentation slide 3-9.

<sup>&</sup>lt;sup>4</sup> May 16 IRP Roundtable presentation 18-2 slide 75-76.



## **Missing factors**

- Value of pumped storage providing sub-hourly ancillary services may not be reflected in PGE's modeling. Pumped storage can provide a variety of sub-hourly ancillary services such as frequency regulation and load-following. We acknowledge that these value streams might already be included in the dispatch model from which PGE derives its value streams. Nevertheless, we wanted to point out explicitly as documentation about this was not clearly available.
- 2. The current modeling goes out to 2050 while evaluating options. We believe that in this context, it is important for PGE to consider the values associated with a resource in the wider-context of the changes going on in the Western grid. For example:
  - a. California recently passed the SB-100 bill that mandates that 100% of California's electricity come from carbon-free sources.
  - b. There are active discussions going on right now about the Enhanced Day-Ahead Market (EDAM) in conjunction with the Energy Imbalance Market (EIM).

Considering these two factors, we believe it is important that PGE consider its portfolio as part of a larger strategic exercise. Pumped storage can be used to meet not only PGE's internal load and GHG-free goals but can also be used to sell carbon-free or renewable energy (depending on whether PGE chooses to shape it or not) to California and other EDAM/EIM entities. Keeping pumped storage's GHG-free nature, its ability to be shaped to renewables, and flexibility in contract-sizing (in this context, PGE can contract more or less from pumped storage to fit-in with its interactions with EDAM/EIM), we believe this is an important source of revenue that should be included while evaluating dispatchable resources, especially when the modeling goes out to 2050 as is the case here. National Grid and Rye Comments – PGE 2019 IRP Comments 10/10/2018 Page 7 of 7

Please let us know if you have any questions or concerns about our comments.

Sincerely,

Note Andrig

Nathan Sandvig Director, US Strategic Growth National Grid Ventures <u>Nathan.Sandvig@nationalgrid.com</u>

Erik Steimle V.P. Project Development Rye Development, LLC Erik@ryedevelopment.com

#### October 10, 2018

Organization: Oregon Department of Energy

IRP Topic(s) and/or agenda item(s): IRP ROSE-E requests

## Comment:

In response to PGE's open call-out for alternative modeling scenarios in relation to PGE's 2019 IRP planning, please find the attached two (2) modeling request forms from the Oregon Dept. of Energy.

- ODOE-PGE-2019IRP-Scenario1
- ODOE-PGE-2019IRP-Scenario1

#### ODOE Scenario 1

- Objective function: Minimize Exp [NPVRR] (with no CO2 emissions b/c biomass and nat. gas plants are given maximums of zero under resource constraints)
- Technology futures: Weighted towards costs of solar and storage go lower than PGE's expectations
- Need futures: Weighted towards need for new resources (load growth) largely tracking PGE's expectations, but with some weight towards load growing more than PGE's expectations
- Price futures: Weighted towards high renewables, high carbon price, high nat. gas price
- Resource constraints: (1) No minimums or maximums for wind, solar, geothermal, or pumped storage; (2) Modest minimums for battery storage deployment (no max); (3) No combustible resources (no biomass or nat. gas plants)

#### **ODOE Scenario 2**

- Objective function: Minimize CO2 emissions
- Technology futures: Weighted towards low cost solar/storage
- Need futures: Weighted towards higher than anticipated demand
- Price futures: Weighted in the direction of four specific futures focused on high CO2 and gas prices
- Resource constraints: Significant constraints on new gas builds, but not eliminated. No other minimum or maximum constraints imposed.

Thank you for providing this valuable opportunity to use PGE's new ROSE-E optimizing program to learn about the potential future resource mixes that could be used to supply electricity to Oregonians.

#### Attachment



# **Stakeholder Portfolio Request Form**

PGE is seeking input from stakeholders regarding portfolios to test in the 2019 IRP. In addition to providing qualitative feedback about proposed portfolios, stakeholders may use this form to make specific portfolio design requests. PGE will apply its best efforts to be responsive to requests made with this form, however depending on the number and nature of stakeholder requested portfolios, not all requested portfolios may be directly modeled in the 2019 IRP.

For consideration prior to IRP Roundtable 18-5 on October 31<sup>st</sup>, please submit this form to IRP@pgn.com by October 10<sup>th</sup>. Requests made after October 10<sup>th</sup> will be considered at a later date.

## **Objective Function**

PGE's portfolio construction tool, ROSE-E, allows the user to design optimized portfolios that best meet a specified objective, given specified constraints. Please choose an objective function from the list below. The default setting is to minimize the expected value of the NPVRR across weighted futures ("Minimize Exp[NPVRR]").

□ Minimize Exp[NPVRR] □ Minimize CO<sub>2</sub> Emissions

## Weights Applied to Futures

Please specify the weights that you would like to apply to each of the futures in the optimization. The default setting is to equally distribute 100 points across each of the futures (e.g., 20 points for each Technology Future, 33.3 points for each Need Future, and 5.56 points for each Price Future). If you would like the optimization to consider only one future, place all 100 points in that future (e.g., to optimize for the Reference Case, place 100 points in the Reference Technology Future, 100 points in the Reference Need Future, and 100 points in the RRRR Price Future).

#### **Technology Futures**

Please distribute 100 points between the following Technology Futures:

Technology Future	Weight	Default
Reference	25	20
Low Cost Wind	10	20
High Cost Wind	15	20
Low Cost Solar and Storage	40	20
High Cost Solar and Storage	10	20
Total	100	100


## Weights Applied to Futures (continued)

#### **Need Futures**

Please distribute 100 points between the following Need Futures:

Need Future	Weight	Default
Reference	60	33.3
Low Need	10	33.3
High Need	30	33.3
Total	100	100

#### Price Futures

Please distribute 100 points between the following Price Futures. Due to computational limitations, all Price Futures listed below correspond to Reference Hydro conditions (i.e. while portfolios are evaluated across Hydro Futures in scoring, portfolio construction does not consider Hydro Futures within the optimization).

Price Future	WECC-wide Renewables	Carbon Price	Gas Price	Weight	Default
RRRR	Reference	Reference	Reference	3	5.56
RRLR	Reference	Reference	Low	2	5.56
RRHR	Reference	Reference	High	4	5.56
RLRR	Reference	Low	Reference	2	5.56
RLLR	Reference	Low	Low	1	5.56
RLHR	Reference	Low	High	3	5.56
RHRR	Reference	High	Reference	4	5.56
RHLR	Reference	High	Low	3	5.56
RHHR	Reference	High	High	6	5.56
HRRR	High Renewables	Reference	Reference	8	5.56
HRLR	High Renewables	Reference	Low	6	5.56
HRHR	High Renewables	Reference	High	10	5.56
HLRR	High Renewables	Low	Reference	6	5.56
HLLR	High Renewables	Low	Low	4	5.56
HLHR	High Renewables	Low	High	8	5.56
HHRR	High Renewables	High	Reference	10	5.56
HHLR	High Renewables	High	Low	8	5.56
HHHR	High Renewables	High	High	12	5.56
Total				100	100



## **Cumulative Resource Procurement Constraints**

PGE's portfolio construction tool allows the user to specify the minimum and/or maximum cumulative procurement of each resource option. These constraints allow the user to force specific resources into portfolios or to exclude specific resources from portfolios. Note that this constraint may conflict with others in the model under certain circumstances (e.g. a maximum procurement limit that prevents the portfolio from meeting resource adequacy requirements will result in an infeasibility). PGE will work to rectify infeasibilities, but this may require modifications to the requested constraints.

Default Settings: Min Cumulative Procurement: 0 MW; Max Cumulative Procurement: 9999 MW

Minimum Cumulative MW	2022	2023	2024	2025	2030	2035	2040	2045	2050
Wind – Ione	0	0	0	0	0	0	0	0	0
Wind – Gorge	0	0	0	0	0	0	0	0	0
Wind – Washington	0	0	0	0	0	0	0	0	0
Wind – Montana	0	0	0	0	0	0	0	0	0
Solar	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0
Batteries (2hr)	50	50	50	100	150	200	200	200	200
Batteries (4hr)	0	0	0	0	0	0	0	0	0
Batteries (6hr)	50	50	50	200	250	300	300	300	300
Pumped Storage	0	0	0	0	0	0	0	0	0
Gas Peaker - LMS 100 (unit = 93 MW)	0	0	0	0	0	0	0	0	0
Gas Peaker – SCCT (unit = 374 MW)	0	0	0	0	0	0	0	0	0
Gas Peaker – Recips (unit = 18 MW)	0	0	0	0	0	0	0	0	0
Gas Combined Cycle (unit = 503 MW)	0	0	0	0	0	0	0	0	0

Please enter your preferred Minimum Cumulative Procurement by resource per year in MW.

Please enter your preferred Maximum Cumulative Procurement by resource per year in MW.

Maximum Cumulative MW	2022	2023	2024	2025	2030	2035	2040	2045	2050
Wind – Ione	9999	9999	9999	9999	9999	9999	9999	9999	9999
Wind – Gorge	9999	9999	9999	9999	9999	9999	9999	9999	9999
Wind – Washington	9999	9999	9999	9999	9999	9999	9999	9999	9999
Wind – Montana	9999	9999	9999	9999	9999	9999	9999	9999	9999
Solar	9999	9999	9999	9999	9999	9999	9999	9999	9999
Biomass	0	0	0	0	0	0	0	0	0
Geothermal	9999	9999	9999	9999	9999	9999	9999	9999	9999
Batteries (2hr)	9999	9999	9999	9999	9999	9999	9999	9999	9999
Batteries (4hr)	9999	9999	9999	9999	9999	9999	9999	9999	9999
Batteries (6hr)	9999	9999	9999	9999	9999	9999	9999	9999	9999
Pumped Storage	9999	9999	9999	9999	9999	9999	9999	9999	9999
Gas Peaker - LMS100 (unit = 93 MW)	0	0	0	0	0	0	0	0	0
Gas Peaker – SCCT (unit = 374 MW)	0	0	0	0	0	0	0	0	0
Gas Peaker – Recips (unit = 18 MW)	0	0	0	0	0	0	0	0	0
Gas Combined Cycle (unit = 503 MW)	0	0	0	0	0	0	0	0	0



## **Cumulative RPS-Eligible Procurement Constraints**

PGE's portfolio construction tool allows the user to specify a minimum and/or maximum cumulative procurement of RPS-eligible resources. These constraints allow the user to force RPS-eligible resources into portfolios without specifying the RPS-eligible technology. Note that this constraint may conflict with others in the model under certain circumstances (e.g. a maximum RPS procurement that prevents compliance with the RPS will result in an infeasibility). PGE will work to rectify infeasibilities, but this may require modifications to the requested constraints.

Default Settings: Min Cumulative Procurement: 0 MWa; Max Cumulative Procurement: 9999 MWa

Please enter your preferred Minimum and Maximum Cumulative RPS Procurement per year in MWa.

MWa	2022	2023	2024	2025	2030	2035	2040	2045	2050
Minimum Cumulative RPS Procurement	0	0	0	0	0	0	0	0	0
Maximum Cumulative RPS Procurement	9999	9999	9999	9999	9999	9999	9999	9999	9999



## Example Inputs for Draft Portfolio R101

## **Objective Function:**

Minimize Exp[NPVRR] 

Minimize CO<sub>2</sub> Emissions

## Weights applied across futures:

- 0 -
20
20
20
20
20
100

Need Future	Weight
Reference	33.3
Low Need	33.3
High Need	33.3
Total	100

Price Future	WECC-wide Renewables	Carbon Price	Gas Price	Weight
RRRR	Reference	Reference	Reference	5.56
RRLR	Reference	Reference	Low	5.56
RRHR	Reference	Reference	High	5.56
RLRR	Reference	Low	Reference	5.56
RLLR	Reference	Low	Low	5.56
RLHR	Reference	Low	High	5.56
RHRR	Reference	High	Reference	5.56
RHLR	Reference	High	Low	5.56
RHHR	Reference	High	High	5.56
HRRR	High Renewables	Reference	Reference	5.56
HRLR	High Renewables	Reference	Low	5.56
HRHR	High Renewables	Reference	High	5.56
HLRR	High Renewables	Low	Reference	5.56
HLLR	High Renewables	Low	Low	5.56
HLHR	High Renewables	Low	High	5.56
HHRR	High Renewables	High	Reference	5.56
HHLR	High Renewables	High	Low	5.56
HHHR	High Renewables	High	High	5.56
Total				100



#### **Cumulative Resource Procurement Constraints:**

Minimum cumulative resource procurement.

These inputs ensure that at least 260 MW of Ione Wind are procured by 2025.

Minimum cumulative MW	2022	2023	2024	2025	2030	2035	2040	2045	2050
Wind – Ione	0	0	0	260	260	260	260	260	260
Wind – Gorge	0	0	0	0	0	0	0	0	0
Wind – Washington	0	0	0	0	0	0	0	0	0
Wind – Montana	0	0	0	0	0	0	0	0	0
Solar	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0
Batteries (2hr)	0	0	0	0	0	0	0	0	0
Batteries (4hr)	0	0	0	0	0	0	0	0	0
Batteries (6hr)	0	0	0	0	0	0	0	0	0
Pumped Storage	0	0	0	0	0	0	0	0	0
Gas Peaker - LMS 100 (unit = 93 MW)	0	0	0	0	0	0	0	0	0
Gas Peaker – SCCT (unit = 374 MW)	0	0	0	0	0	0	0	0	0
Gas Peaker – Recips (unit = 18 MW)	0	0	0	0	0	0	0	0	0
Gas Combined Cycle (unit = 503 MW)	0	0	0	0	0	0	0	0	0

#### Maximum cumulative resource procurement

These inputs ensure that procurement of Ione Wind between 2022 and 2025 does not exceed 260. These inputs ensure that any capacity needs in 2022 through 2025 are met with 4-hr batteries.

Maximum cumulative MW	2022	2023	2024	2025	2030	2035	2040	2045	2050
Wind – Ione	260	260	260	260	9999	9999	9999	9999	9999
Wind – Gorge	0	0	0	0	9999	9999	9999	9999	9999
Wind – Washington	0	0	0	0	9999	9999	9999	9999	9999
Wind – Montana	0	0	0	0	9999	9999	9999	9999	9999
Solar	0	0	0	0	9999	9999	9999	9999	9999
Biomass	0	0	0	0	9999	9999	9999	9999	9999
Geothermal	0	0	0	0	9999	9999	9999	9999	9999
Batteries (2hr)	0	0	0	0	9999	9999	9999	9999	9999
Batteries (4hr)	9999	9999	9999	9999	9999	9999	9999	9999	9999
Batteries (6hr)	0	0	0	0	9999	9999	9999	9999	9999
Pumped Storage	0	0	0	0	9999	9999	9999	9999	9999
Gas Peaker - LMS100 (unit = 93 MW)	0	0	0	0	9999	9999	9999	9999	9999
Gas Peaker – SCCT (unit = 374 MW)	0	0	0	0	9999	9999	9999	9999	9999
Gas Peaker – Recips (unit = 18 MW)	0	0	0	0	9999	9999	9999	9999	9999
Gas Combined Cycle (unit = 503 MW)	0	0	0	0	9999	9999	9999	9999	9999

#### **Cumulative RPS-Eligible Procurement Constraints:**

MWa	2022	2023	2024	2025	2030	2035	2040	2045	2050
Minimum Cumulative RPS Procurement	0	0	0	0	0	0	0	0	0
Maximum Cumulative RPS Procurement	9999	9999	9999	9999	9999	9999	9999	9999	9999



## **Stakeholder Portfolio Request Form**

PGE is seeking input from stakeholders regarding portfolios to test in the 2019 IRP. In addition to providing qualitative feedback about proposed portfolios, stakeholders may use this form to make specific portfolio design requests. PGE will apply its best efforts to be responsive to requests made with this form, however depending on the number and nature of stakeholder requested portfolios, not all requested portfolios may be directly modeled in the 2019 IRP.

For consideration prior to IRP Roundtable 18-5 on October 31<sup>st</sup>, please submit this form to IRP@pgn.com by October 10<sup>th</sup>. Requests made after October 10<sup>th</sup> will be considered at a later date.

## **Objective Function**

PGE's portfolio construction tool, ROSE-E, allows the user to design optimized portfolios that best meet a specified objective, given specified constraints. Please choose an objective function from the list below. The default setting is to minimize the expected value of the NPVRR across weighted futures ("Minimize Exp[NPVRR]").

□ Minimize Exp[NPVRR] □ Minimize CO<sub>2</sub> Emissions

#### Weights Applied to Futures

Please specify the weights that you would like to apply to each of the futures in the optimization. **The default setting is to equally distribute 100 points across each of the futures** (e.g., 20 points for each Technology Future, 33.3 points for each Need Future, and 5.56 points for each Price Future). If you would like the optimization to consider only one future, place all 100 points in that future (e.g., to optimize for the Reference Case, place 100 points in the Reference Technology Future, 100 points in the Reference Need Future, and 100 points in the RRRR Price Future).

#### **Technology Futures**

Please distribute 100 points between the following Technology Futures:

Technology Future	Weight	Default
Reference	20	20
Low Cost Wind	20	20
High Cost Wind	20	20
Low Cost Solar and Storage	35	20
High Cost Solar and Storage	5	20
Total	100	100



## Weights Applied to Futures (continued)

#### **Need Futures**

Please distribute 100 points between the following Need Futures:

Need Future	Weight	Default
Reference	30	33.3
Low Need	30	33.3
High Need	40	33.3
Total	100	100

#### Price Futures

Please distribute 100 points between the following Price Futures. Due to computational limitations, all Price Futures listed below correspond to Reference Hydro conditions (i.e. while portfolios are evaluated across Hydro Futures in scoring, portfolio construction does not consider Hydro Futures within the optimization).

Price Future	WECC-wide Renewables	Carbon Price	Gas Price	Weight	Default
RRRR	Reference	Reference	Reference	4	5.56
RRLR	Reference	Reference	Low	3	5.56
RRHR	Reference	Reference	High	4	5.56
RLRR	Reference	Low	Reference	4	5.56
RLLR	Reference	Low	Low	3	5.56
RLHR	Reference	Low	High	4	5.56
RHRR	Reference	High	Reference	12.5	5.56
RHLR	Reference	High	Low	3	5.56
RHHR	Reference	High	High	12.5	5.56
HRRR	High Renewables	Reference	Reference	4	5.56
HRLR	High Renewables	Reference	Low	3	5.56
HRHR	High Renewables	Reference	High	4	5.56
HLRR	High Renewables	Low	Reference	4	5.56
HLLR	High Renewables	Low	Low	3	5.56
HLHR	High Renewables	Low	High	4	5.56
HHRR	High Renewables	High	Reference	12.5	5.56
HHLR	High Renewables	High	Low	3	5.56
HHHR	High Renewables	High	High	12.5	5.56
Total				100	100



## **Cumulative Resource Procurement Constraints**

PGE's portfolio construction tool allows the user to specify the minimum and/or maximum cumulative procurement of each resource option. These constraints allow the user to force specific resources into portfolios or to exclude specific resources from portfolios. Note that this constraint may conflict with others in the model under certain circumstances (e.g. a maximum procurement limit that prevents the portfolio from meeting resource adequacy requirements will result in an infeasibility). PGE will work to rectify infeasibilities, but this may require modifications to the requested constraints.

Default Settings: Min Cumulative Procurement: 0 MW; Max Cumulative Procurement: 9999 MW

Minimum Cumulative MW	2022	2023	2024	2025	2030	2035	2040	2045	2050
Wind – Ione	0	0	0	0	0	0	0	0	0
Wind – Gorge	0	0	0	0	0	0	0	0	0
Wind – Washington	0	0	0	0	0	0	0	0	0
Wind – Montana	0	0	0	0	0	0	0	0	0
Solar	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0
Batteries (2hr)	0	0	0	0	0	0	0	0	0
Batteries (4hr)	0	0	0	0	0	0	0	0	0
Batteries (6hr)	0	0	0	0	0	0	0	0	0
Pumped Storage	0	0	0	0	0	0	0	0	0
Gas Peaker - LMS 100 (unit = 93 MW)	0	0	0	0	0	0	0	0	0
Gas Peaker – SCCT (unit = 374 MW)	0	0	0	0	0	0	0	0	0
Gas Peaker – Recips (unit = 18 MW)	0	0	0	0	0	0	0	0	0
Gas Combined Cycle (unit = 503 MW)	0	0	0	0	0	0	0	0	0

Please enter your preferred Minimum Cumulative Procurement by resource per year in MW.

Please enter your preferred Maximum Cumulative Procurement by resource per year in MW.

Maximum Cumulative MW	2022	2023	2024	2025	2030	2035	2040	2045	2050
Wind – Ione	9999	9999	9999	9999	9999	9999	9999	9999	9999
Wind – Gorge	9999	9999	9999	9999	9999	9999	9999	9999	9999
Wind – Washington	9999	9999	9999	9999	9999	9999	9999	9999	9999
Wind – Montana	9999	9999	9999	9999	9999	9999	9999	9999	9999
Solar	9999	9999	9999	9999	9999	9999	9999	9999	9999
Biomass	9999	9999	9999	9999	9999	9999	9999	9999	9999
Geothermal	9999	9999	9999	9999	9999	9999	9999	9999	9999
Batteries (2hr)	9999	9999	9999	9999	9999	9999	9999	9999	9999
Batteries (4hr)	9999	9999	9999	9999	9999	9999	9999	9999	9999
Batteries (6hr)	9999	9999	9999	9999	9999	9999	9999	9999	9999
Pumped Storage	9999	9999	9999	9999	9999	9999	9999	9999	9999
Gas Peaker - LMS100 (unit = 93 MW)	0	0	0	0	465	465	465	465	465
Gas Peaker – SCCT (unit = 374 MW)	0	0	0	0	0	0	0	0	0
Gas Peaker – Recips (unit = 18 MW)	0	0	0	0	0	0	0	0	0
Gas Combined Cycle (unit = 503 MW)	0	0	0	0	503	503	503	503	503



## **Cumulative RPS-Eligible Procurement Constraints**

PGE's portfolio construction tool allows the user to specify a minimum and/or maximum cumulative procurement of RPS-eligible resources. These constraints allow the user to force RPS-eligible resources into portfolios without specifying the RPS-eligible technology. Note that this constraint may conflict with others in the model under certain circumstances (e.g. a maximum RPS procurement that prevents compliance with the RPS will result in an infeasibility). PGE will work to rectify infeasibilities, but this may require modifications to the requested constraints.

Default Settings: Min Cumulative Procurement: 0 MWa; Max Cumulative Procurement: 9999 MWa

Please enter your preferred Minimum and Maximum Cumulative RPS Procurement per year in MWa.

MWa	2022	2023	2024	2025	2030	2035	2040	2045	2050
Minimum Cumulative RPS Procurement	0	0	0	0	0	0	0	0	0
Maximum Cumulative RPS Procurement	9999	9999	9999	9999	9999	9999	9999	9999	9999



## Example Inputs for Draft Portfolio R101

## **Objective Function:**

Minimize Exp[NPVRR] 

Minimize CO<sub>2</sub> Emissions

## Weights applied across futures:

0 -
20
20
20
20
20
100

Need Future	Weight
Reference	33.3
Low Need	33.3
High Need	33.3
Total	100

Price Future	WECC-wide Renewables	Carbon Price	Gas Price	Weight
RRRR	Reference	Reference	Reference	5.56
RRLR	Reference	Reference	Low	5.56
RRHR	Reference	Reference	High	5.56
RLRR	Reference	Low	Reference	5.56
RLLR	Reference	Low	Low	5.56
RLHR	Reference	Low	High	5.56
RHRR	Reference	High	Reference	5.56
RHLR	Reference	High	Low	5.56
RHHR	Reference	High	High	5.56
HRRR	High Renewables	Reference	Reference	5.56
HRLR	High Renewables	Reference	Low	5.56
HRHR	High Renewables	Reference	High	5.56
HLRR	High Renewables	Low	Reference	5.56
HLLR	High Renewables	Low	Low	5.56
HLHR	High Renewables	Low	High	5.56
HHRR	High Renewables	High	Reference	5.56
HHLR	High Renewables	High	Low	5.56
HHHR	High Renewables	High	High	5.56
Total				100

### **Cumulative Resource Procurement Constraints:**

Minimum cumulative resource procurement.

These inputs ensure that at least 260 MW of Ione Wind are procured by 2025.

Minimum cumulative MW	2022	2023	2024	2025	2030	2035	2040	2045	2050
Wind – Ione	0	0	0	260	260	<b>260</b>	260	260	260
Wind – Gorge	0	0	0	0	0	0	0	0	0
Wind – Washington	0	0	0	0	0	0	0	0	0
Wind – Montana	0	0	0	0	0	0	0	0	0
Solar	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0
Batteries (2hr)	0	0	0	0	0	0	0	0	0
Batteries (4hr)	0	0	0	0	0	0	0	0	0
Batteries (6hr)	0	0	0	0	0	0	0	0	0
Pumped Storage	0	0	0	0	0	0	0	0	0
Gas Peaker - LMS 100 (unit = 93 MW)	0	0	0	0	0	0	0	0	0
Gas Peaker – SCCT (unit = 374 MW)	0	0	0	0	0	0	0	0	0
Gas Peaker – Recips (unit = 18 MW)	0	0	0	0	0	0	0	0	0
Gas Combined Cycle (unit = 503 MW)	0	0	0	0	0	0	0	0	0

#### Maximum cumulative resource procurement

These inputs ensure that procurement of Ione Wind between 2022 and 2025 does not exceed 260. These inputs ensure that any capacity needs in 2022 through 2025 are met with 4-hr batteries.

Maximum cumulative MW	2022	2023	2024	2025	2030	2035	2040	2045	2050
Wind – Ione	260	260	260	260	9999	9999	9999	9999	9999
Wind – Gorge	0	0	0	0	9999	9999	9999	9999	9999
Wind – Washington	0	0	0	0	9999	9999	9999	9999	9999
Wind – Montana	0	0	0	0	9999	9999	9999	9999	9999
Solar	0	0	0	0	9999	9999	9999	9999	9999
Biomass	0	0	0	0	9999	9999	9999	9999	9999
Geothermal	0	0	0	0	9999	9999	9999	9999	9999
Batteries (2hr)	0	0	0	0	9999	9999	9999	9999	9999
Batteries (4hr)	9999	9999	9999	9999	9999	9999	9999	9999	9999
Batteries (6hr)	0	0	0	0	9999	9999	9999	9999	9999
Pumped Storage	0	0	0	0	9999	9999	9999	9999	9999
Gas Peaker - LMS100 (unit = 93 MW)	0	0	0	0	9999	9999	9999	9999	9999
Gas Peaker – SCCT (unit = 374 MW)	0	0	0	0	9999	9999	9999	9999	9999
Gas Peaker – Recips (unit = 18 MW)	0	0	0	0	9999	9999	9999	9999	9999
Gas Combined Cycle (unit = 503 MW)	0	0	0	0	9999	9999	9999	9999	9999

#### **Cumulative RPS-Eligible Procurement Constraints:**

MWa	2022	2023	2024	2025	2030	2035	2040	2045	2050
Minimum Cumulative RPS Procurement	0	0	0	0	0	0	0	0	0
Maximum Cumulative RPS Procurement	9999	9999	9999	9999	9999	9999	9999	9999	9999

November 8, 2018

Organization: Absaroka Energy

IRP Topic(s) and/or agenda item(s): Energy storage sensitivities for 2019 IRP

Comment:

The purpose of this communication is to request that the PGE IRP Team run certain sensitivity studies to address issues arising from input values for energy storage resource costs and other characteristics that PGE adopted without an opportunity for comment by stakeholders. Specifically, PGE has adopted cost and, possibly, other assumptions for batteries that are too optimistic and operating parameters for pumped storage hydro (PSH) that are too restrictive.

These concerns can be addressed, and the significance of the input assumptions can be tested, by adding the following sensitivities to the Dispatchable Resource Portfolios depicted on pages 96-100 of the Roundtable 18-5 presentation.

- Portfolio D1a 400 MW of 2-hour batteries. Increase battery Overnight Capital Cost<sup>1</sup> by 50% and limit battery life to no more than 10 years<sup>2</sup>.
- Portfolio D2a 250 MW of 4-hour batteries (increased from 200 MW to reflect lower ELCC contribution compared to longer duration storage resources). Increase battery Overnight Capital Cost by 50% and limit battery life to no more than 10 years.
- Portfolio D3a 200 MW of 6-hour batteries. Increase battery Overnight Capital Cost by 50% and limit battery life to no more than 10 years.
- Portfolio S7a 200 MWH of PSH. PGE 2019 IRP Draft Supply Side Option Summary Information dated October 5, 2018 includes performance characteristics (minimum pumping and generation limits) that severely restrict the operating flexibility of PSH. It is not clear if these restrictions were modelled in Portfolio S7. If so, please add Portfolio S7a without these restrictions, so that the full generation/pumping range is available as would be the case with ternary and quaternary PSH designs.

In addition, I would like to request that a sensitivity case be added to any flexible capacity analysis that considers PSH so that the ternary and quaternary technologies are represented.

<sup>&</sup>lt;sup>1</sup> Overnight Capital Cost as shown in PGE 2019 IRP Draft Supply Side Option Summary Information dated October 5, 2018.

<sup>&</sup>lt;sup>2</sup> Resource life is not specified in PGE 2019 IRP Draft Supply Side Option Summary Information dated October 5, 2018.

November 8, 2018

Organization: Orion Renewables

IRP Topic(s) and/or agenda item(s): Wind resource sensitivities for 2019 IRP

Comment:

The purpose of this communication is to request that the PGE IRP Team run certain sensitivity studies to address issues arising from input values for wind resource costs and other characteristics that PGE adopted without an opportunity for comment by stakeholders. Specifically, PGE has adopted capacity factors for wind resources that I believe are too high for the Gorge and Washington resources and too low for Montana.

This concern can be addressed, and the significance of the capacity factor assumptions can be tested, by adding the following sensitivities to the Renewable Resource Portfolios depicted on pages 91-95 of the Roundtable 18-5 presentation.

- Portfolio R2a Replace Gorge wind (40.8% CF) in Portfolio R2 with 90 aMW of Gorge wind with a 37% CF.
- Portfolio R3a Replace Washington wind (42.9% CF) in Portfolio R3 with 90 aMW of Washington wind with a 37% CF.
- Portfolio R4a Replace Montana wind (42.9% CF) in Portfolio R4 with 90 aMW of Montana wind with a 46% CF.

In addition, I would like to reiterate my request for an opportunity to review and comment on the Montana transmission assumptions that will be used in the 2019 IRP.

November 9, 2018

Organization: Renewable Northwest

IRP Topic(s) and/or agenda item(s): IRP portfolio request

Comment:

Consistent with PGE's October 31 IRP Presentation, slide 106, Renewable Northwest supports PGE exploring optimized portfolios that look at maximum annual resource addition as a way to explore a smoother ramp up in renewables than what portfolios like O1 and S1 identify. We suggest an annual addition cap for wind and solar equivalent to at least 175 aMW per year or a greater amount that PGE considers reasonable.

Renewable Northwest also requests that PGE explores in a future workshop the challenges that it perceives could result from renewable procurement levels in a single year like those identified in portfolios O1 and S1.

## Attachment A: 2019 IRP Stakeholder Comment Record

December 10, 2018

Organization: National Grid and Rye Development

IRP Topic(s) and/or agenda item(s): Comments on roundtable 18-6

Comment:

Please find attached our comments from the last IRP stakeholder meeting for your consideration.

# national**grid**

December 10, 2018

Elaine Hart Manager-Integrated Resource Planning Portland General Electric 121 SW Salmon St. Portland, Oregon 97204

RE: Roundtable 18-6, November 28, 2018

Ms. Hart and the PGE IRP Staff,

Thank you for the opportunity to comment on the November 28, 2018 Integrated Resource Planning (IRP) presentation. The presentation was very helpful and it is clear that PGE's team is making good progress in developing its analyses for the 2019 IRP. In particular, PGE's new ways of presenting complex data from its portfolio modeling are very helpful in understanding the results. The following are our comments for your consideration:

## **Portfolio Construction**

We see in the evaluation of renewable resource portfolios (slide 12) that each renewable energy resource is accompanied by a certain amount of four-hour batteries to provide capacity needed to achieve resource sufficiency for that portfolio. Presumably the addition of batteries results from an optimization of resources available to provide the needed capacity to complete each portfolio. If not, PGE should perform an analysis to identify the optimal capacity resource to meet reserve and reliability requirements for each portfolio. We encourage PGE to consider all resources able to provide capacity, including pumped storage hydroelectric (PSH), and to perform its optimization over a time period that captures the long-term benefits of PSH and accounts for all the costs and benefits associated with operation of a given portfolio.

## **Investment Tax Credit**

The proposed Energy Storage Tax Incentive and Deployment Act of 2017 (S. 1868 and H.R. 4649) would make all storage technologies eligible for the federal investment tax credit (ITC), not just storage co-located with an ITC-eligible renewable energy facility as is currently the case. The legislation has broad support as indicated by the 17 business associations and 134 individual companies that signed a <u>letter</u> of support delivered to Congress on December 10, 2018. Given this proposed legislation, PGE should also consider a sensitivity that makes both batteries and PSH eligible for the ITC regardless of whether solar or wind resources are part of the project.

## **Operating Life**

During the discussion of slide 16, PGE indicated that PSH was modeled with an assumed life of 38 years and batteries were assumed to have a life of 20 years. We disagree with the assumed life of 38 years for PSH. In fact, PSH resources have an expected operating life of at least 50 years or more, as indicated on page 49 of the Thermal and Pumped Storage Supply Side Resource report prepared for PGE by HDR Inc. It is unclear why the associated assumptions spreadsheet provided by HDR lists an expected life of 38 years for PSH. We note that the value is the same as that assumed for gas turbine resources, so it may have to do with values being truncated by the study period. Whatever the reason, PGE should confirm with HDR the actual expected lives of each technology and use updated values for its economic assessment.

Likewise, an assumed 20-year life for chemical batteries seems very aggressive, especially given the lack of a track record for operating these technologies. We understand that operating costs are intended to reflect the costs associated with achieving the assumed 20-year life. However, given the uncertainty of these costs, we recommend a conservative approach that either assumes a shorter life or higher operating costs.

## **Portfolio Screening**

Given PGE's goal to reduce GHG emissions by 80 percent by 2050 and the long-term scope of integrated resource planning, it does not seem appropriate to screen portfolios on the basis of near-term costs (slide 27). Doing so may have the effect of screening out technologies that have high up-front costs but lower costs over the long term. It is also unnecessary, given that portfolio rankings are based on the present value revenue requirements that incorporates a discount rate reflecting the time value of money. Truncating that evaluation period to focus on the near-term introduces an arbitrary element that may affect the results. For example, the PVRR method theoretically evens out some of the differences between utility-owned and independent resources. However, a project proposed as a PPA with escalating prices would perform differently under a near-term cost screen than would a levelized utility project, even if the PVRRs are the same over the project life. If PGE maintains the near-term screen, it should consider evaluating costs assuming PPAs with escalating prices.

Depending on how PGE has developed the portfolios being evaluated, it may be appropriate to introduce a screen to ensure that only projects with feasible transmission access are considered for ranking. The need for and approach to developing such screens may be appropriate for discussion at the December 19 Roundtable. This discussion could include PGE's rights on various paths (e.g., 600 MW N/S rights on the AC Intertie). It would be helpful to understand PGE's utilization of its existing rights (broken out for load service and merchant sales), ways in which the value of these rights may be increased and how to reflect that value in the IRP analyses.

## **Presenting Capacity Needs**

The renewable glide path charts (slides 34-36) do a good job of showing the energy contribution provided by renewable energy additions under different scenarios. It would also be helpful to show the capacity contribution of the renewable resources, with the capacity requirements from slide 61 overlaid to show the remaining capacity need.

## **Sensitivities**

In addition to evaluating storage cost uncertainties, we recommend that PGE also consider sensitivities that evaluate different expected lifespans of battery projects and the impact on costs.

## Flexibility Adequacy Study

Slide 40 states that the Flexibility Adequacy Study includes the assumption that PGE has the option in 2025 to purchase 600 MW of generic on-peak day-ahead capacity in 100 MW blocks. Apparently, this is consistent with the draft RECAP analysis (E3's loss-of-load probability study). It would be helpful in future presentations/reports to provide further explanation of this assumption and how it is consistent with E3's assessment of a tightening capacity balance in the region.

Slide 45 shows PSH and batteries as having the same flexibility value (~\$40/kW-yr), with no variation by the duration of storage. It would be helpful in future presentations to provide a more granular breakdown of the Flexibility Value components (perhaps it is necessary to wait for ROM results for this detail, but the current results do not seem intuitive given the different capabilities of the technologies).

## **Experience Curve Analysis**

Slides 72-73 show experience curves for 4-hour batteries. It would be helpful to see your experience curve assumptions for batteries of different durations as well as PSH. Below is a chart that provides a useful format for comparing storage technologies and the differential impact of energy storage duration on capital costs. PGE may consider using a similar format in future presentations of storage cost assumptions.



Please let us know if you have any questions or concerns about our comments.

Sincerely,

Nate Semding

Nathan Sandvig Director, US Strategic Growth National Grid Ventures Nathan.Sandvig@nationalgrid.com

Erik Steimle V.P. Project Development Rye Development, LLC Erik@ryedevelopment.com

#### December 19, 2018

Organization: Renewable Northwest

IRP Topic(s) and/or agenda item(s): Renewable Northwest's Comments on roundtable 18-6

Comment: Renewable Northwest thanks PGE for this opportunity to provide feedback as the Company prepares its 2019 IRP. We appreciate the Company's efforts and thoughtful process. Our feedback focuses on the Company's exploration of resource glide paths, the proposed screens and flexibility analysis presented at the November roundtable, and the Company's consideration of solar+storage and pumped hydro storage. Finally, we suggest that the Company compiles a handout with portfolios under discussion.

#### PGE's Exploration of Resource Glide Paths

Renewable Northwest understands PGE's interest in exploring resource glide paths by imposing constraints (e.g. a capacity addition constraint) in ROSE-E. However, we discourage PGE from excluding from consideration the well-performing portfolios that ROSE-E identified without any constraints and that PGE presented prior to its November 28, 2018 IRP Roundtable #18-6. For example, portfolios O1, S1, and S8 merit continued consideration because they could represent least-cost, least-risk solutions. Excluding them at this stage would deprive PGE, stakeholders, and eventually also the Commission, of important information and would foreclose potential least-cost, least-risk action plans that may be in the best interest of the Company's customers.

Additionally, we are concerned with the capacity addition constraint that led to the portfolios that PGE presented at its Roundtable #18-6. Given PGE's interest in exploring a glide path, Renewable Northwest suggested that any annual capacity addition constraint should reflect at least 175 aMW of renewable energy resources (i.e. approximately 570 MW assuming a 33.3% CF resource). We made that recommendation because the Company expressed comfort with integrating a procurement of that size in its original 2016 IRP action plan and because it would allow for greater flexibility in this process. If PGE continues exploring a capacity addition constraint, we reiterate our recommendation that PGE explores a constraint that reflects at least 175 aMW/year of renewable energy resources.

#### **Proposed Screens**

Renewable Northwest appreciates PGE's need to identify a subset of portfolios to further investigate as part of this process. We support PGE's proposal to use GHG and non-GHG emissions as a screens to identify that subset. However, Renewable Northwest discourages PGE from relying on near-term cost to screen out portfolios. While the near-term cost of a portfolio provides relevant context to the utility's planning efforts, the IRP is a long-term plan and, as PGE found in the 2016 IRP and 2018 RFP, inaction in the near-term can also have a cost to customers. As a result, we consider it inappropriate for PGE to rely on near-term costs to eliminate portfolios from consideration.

#### **Flexibility Analysis**

Renewable Northwest commends PGE for its efforts to assess its flexibility needs as well as the different options to meet them. However, Renewable Northwest outlines the following concerns about the proposals and materials that PGE presented at its Roundtable #18-6:

Renewable Northwest is concerned about the estimated integration costs that PGE presented, particularly its estimated solar integration cost. We plan to request a meeting with the Company to

## Attachment A: 2019 IRP Stakeholder Comment Record

better understand its methodology and assumptions so that we can provide feedback in collaboration with members of the solar industry.

We are also concerned about PGE's current flexibility values in ROSE-E. While we appreciate PGE's efforts to quantify the flexibility value of particular resources, we are concerned that PGE assigns a zero flexibility value for renewable energy resources. We are particularly concerned in light of similar efforts to quantify the flexibility value of resources, undertaken by PacifiCorp, found a flexibility value for renewables greater than zero (See PacifiCorp's presentation at slide 12). We plan to also meet with PGE to explore in greater detail the methodology and assumptions underlying its current flexibility values, and compare them to other utilities' approaches.

We strongly encourage PGE to explore the flexibility value of renewables plus storage. Doing so will allow PGE to run a process informed by more complete information and be consistent with the IRP Guidelines requirement that the utility consider all known resources for meeting its load.

#### Solar+Storage

Renewable Northwest thanks PGE for adding solar+storage to the resource options considered for its 2019 IRP. However, we encourage the utility to make available its cost and performance assumptions for this resource. As of the date of these comments, we were unable to find that information in the report that HDR prepared for PGE.

#### **Pumped Storage**

Renewable Northwest echoes feedback provided by other participants regarding PGE's assumptions for the life of pumped hydro storage projects. Our understanding is that pumped hydro storage projects have a life significantly greater than PGE's current assumption of 38 years. We encourage the utility to use life assumptions that better reflect what we understand is the actual life of pumped hydro storage resources.

#### Portfolio Handout

Given the increasing number of portfolios under consideration, Renewable Northwest encourages PGE to create a handout outlining the different portfolios that it is exploring and to update that handout as the company explores new portfolios.

## Attachment A: 2019 IRP Stakeholder Comment Record

January 10, 2019

Organization: Rye Development and National Grid

IRP Topic(s) and/or agenda item(s): Transmission assumptions

Comment:

Please accept these comments on behalf of Rye Development and National Grid.

# national**grid**

January 10, 2019

Elaine Hart Manager-Integrated Resource Planning Portland General Electric By email to: <u>IRP@pgn.com</u> and Elaine.Hart@pgn.com

RE: Transmission Assumptions and Analysis is PGE's 2019 IRP.

Ms. Hart and the PGE IRP Staff,

National Grid and Rye Development appreciate the opportunity to submit comments. Feel free to post these comments to the PGE IRP website.

## **Transmission**

During the presentations and in response to stakeholder questions, PGE staff indicated that the IRP process assumes that transmission is available on neighboring systems at the transmission provider's published rates.

In the past, this may have been a reasonable assumption. But in light of the Bonneville Power Administration's (BPA) decision on the I-5 Corridor Project dated May 17, 2017 (attached), however, that assumption is no longer appropriate. Traditionally, BPA would manage congestion on its grid by building new transmission lines or upgrading existing one. The I-5 Corridor letter reflects a decision by BPA to take a new approach to managing congestion on its transmission system. Going forward, BPA will no longer necessarily expand capacity on its transmission system. Instead BPA has decided to embrace a "more flexible, scalable, and economically and operationally efficient approach to managing [it's] transmission system." Accordingly, it is incumbent upon PGE to begin to incorporate BPA's new policy into its own planning.

While BPA is still in the process of identifying and implementing mechanisms to achieve its stated vision of a more flexible, scalable and efficient transmission system, what is clear is that BPA can no longer be relied upon to build new lines or upgrade existing lines to meet new demand for transmission. It is also clear that it will be some time before BPA identifies and implements the alternatives touched on it its May 17 decision letter. Accordingly, we suggest that it is no longer appropriate for PGE's IRP to assume that transmission will be automatically available to support interconnection and delivery of new generation resources to meet PGE's forecasted needs.

In its IRP, PGE is evaluating likely scenarios based on assumptions related to generation characteristics and projected future costs. PGE has collected vast

quantities of data and deployed complex models and analytical tools to carefully consider a wide range of factors in its IRP process including forecast stream flows, load growth, load changes, generation capacity needs, flexible capacity needs, future costs of generation resources, Renewable Energy Certificate banking, wholesale energy market price forecasts, impacts of flexible load and impacts of distributed energy resources. We suggest that failing to apply the same level of intellectual rigor to transmission availability would be a mistake.

As PGE noted in one of its early IRP presentations, OPUC Order No. 07-047 Guideline 1(c) specifies that the "primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers." Simply assuming that transmission is equally available to all of the draft generation resource portfolios to be considered in the IRP process ignores a significant known uncertainty that transmission may not be available in the quantities required.

We offer the following suggestions for data to be collected related to transmission availability:

1. Transmission Upgrades

PGE should identify the transmission upgrades to its system that PGE has planned to come on line during the time period covered by the IRP. Data should include the project, the commercial operation date, the impact to total transfer capability and identify any customer that capacity is committed to (including capacity committed to meet PGE load growth).

2. Inventory of available transmission capacity on neighboring systems.

PGE should determine how much uncommitted transmission capacity is available on neighboring systems to deliver energy from new generation resources identified in the draft portfolios. PGE must recognize, however, that the absence of currently available transmission on neighboring systems does not preclude the possibility that an existing project or a project under development may have already secured transmission rights that would be sufficient to reach PGE (but that would no longer be available to other customers in the transmission queue). An accurate analysis of transmission availability would include gathering and analyzing the transmission rights held by developers of projects associated with the draft portfolios.

## 3. Inventory of PGE transmission capacity

In addition to determining how much unsubscribed transmission is available on neighboring systems is available to serve load on PGE's system, PGE should identify its existing rights on neighboring transmission systems (including ownership rights, existing transmission reservations, queued transmission service requests, or contractual rights National Grid and Rye Comments – PGE 2019 IRP Comments 1/10/2019 Page **3** of **3** 

to take control of transmission service) that would be available to support delivery of resources identified in the draft portfolios to PGE's system.

4. Transmission utilization factor

For each PGE owned transmission path, what is the path utilization factor? For each PGE transmission reservation on neighboring systems, what is the utilization factor of the reservation? Ideally, PGE would identify a utilization factor that reflects how often each reservation is used to serve PGE load and a separate utilization factor that reflects how often each reservation is used to support off system sales or other marketing activity. For transmission reservations that could support both load service and off system sales, PGE should explain why any of those reservations are used primarily for off system sales.

5. Alternatives to Firm Transmission

Does PGE assume that it will require firm transmission rights for resources identified in the draft portfolios? Especially for resources added to meet the need for renewable capacity, PGE should consider whether there is a lower cost and risk associated with using an alternative to firm transmission rights (conditional firm or non-firm).

Please let us know if you have any questions or concerns about our comments.

Sincerely,

Nate Andrig

Nathan Sandvig Director, US Strategic Growth National Grid Ventures <u>Nathan.Sandvig@nationalgrid.com</u>

Erik Steimle V.P. Project Development Rye Development, LLC <u>Erik@ryedevelopment.com</u>



## **Department of Energy**

Bonneville Power Administration P.O. Box 3621 Portland, Oregon 97208-3621

EXECUTIVE OFFICE

May 17, 2017

In reply refer to: A-7

To parties interested in the I-5 Corridor Reinforcement Project:

The Bonneville Power Administration has completed an extensive analysis of the need for the I-5 Corridor Reinforcement Project and decided not to build the proposed transmission line. This decision caps an intensive review that included one of the most comprehensive public engagement processes BPA has ever undertaken. Much has changed since BPA proposed the transmission line, and I have concluded that constructing the line would not fulfill our commitment to making the right investment at the right time.

BPA proposed the I-5 Corridor Reinforcement project in 2009 as a solution to preserve reliability, meet existing contract requirements, reduce curtailments, and serve demand on the transmission system – which at the time was growing. More recently, BPA considered the size, local impacts and increasing costs of the proposed project, which prompted us to take a hard look at all of our transmission practices and analytics, including a fresh look at load (electrical demand) forecasts, generation changes and market dynamics.

As a result of this comprehensive review and the inherent difficulties associated with building this line, we are taking a new approach to managing congestion on our transmission grid. My decision today reflects a shift for BPA – from the traditional approach of primarily relying on new construction to meet changing transmission needs, to embracing a more flexible, scalable, and economically and operationally efficient approach to managing our transmission system. We will also increase our reliance on advanced technology, robust regional planning, industry standard commercial practices and coordinated system operations.

Going forward, we will leverage the tools of the modern energy economy to maximize the value of federal assets for our customers and the broader region. Through the transformational efforts described below, we will maximize grid availability, use and reliability to support economic growth along this and other important transmission corridors.

To those who have been with us every step of the way, I would like to acknowledge and thank you for the time you invested in reading our material, attending meetings and providing comments as we took nearly nine years at significant cost to complete a comprehensive review of the project and its potential impacts. This was a difficult decision, compounded by many technically complex and moving parts, and I understand the uncertainty this created for the landowners and homeowners along the route alternatives. Though the process was lengthy, I simply could not risk making a decision of this magnitude without first acquiring the best possible information, and I can say with confidence today that Bonneville is making the best decision for the region.

#### A summary of our in-depth review

In September 2016 we convened an independent review panel of industry experts to review study assumptions, methodologies, results and assessments supporting the need for the I-5 Corridor Reinforcement Project. The panel concluded that "the proposed 500-kV line could meet the reliability needs..., but that line will add far more capacity than is required for reliability alone." We agreed.

We also observed changes to our regional power system and transmission reliability planning standards. For example, the proposed transmission line would have helped manage the summer congestion impacts of power that flows north to south across the South of Allston flowgate – the portion of the transmission grid this project would have augmented. Contributing to this congestion is power from the coal-fired generators in Centralia, Washington, that are required by state law to close in 2020 and 2025. This should help relieve summer congestion, depending on where replacement generation is sited. Additionally, new national reliability regulations took effect in January 2016. These reliability standards changed the way line limits are calculated. This new standard will increase the potential for other regional utilities to consider infrastructure upgrades or additions that would provide additional transmission capacity and relieve congestion in this corridor.

Further, recent trends indicate that load growth has generally slowed relative to what was assumed in prior studies. However, we are also seeing the potential rapid development of large loads associated with the technology sector that could add hundreds of megawatts of baseload demand in a concentrated geographic area. Meeting the needs of such sudden and unexpected loads is a demanding task, whether through builds, technology or business changes. In this case, where we have decided against building the proposed project, Bonneville and its regional utility partners will need to maximize the use of modern approaches to grid design to meet load growth and economic development objectives.

#### **Moving forward**

We will be transforming our approach to adding transmission capacity by making more scalable and flexible investments in the federal transmission system. Focused effort will be given to integrated coordination of operations, transmission planning and commercial processes to support our product portfolio. Bonneville will need to establish a new level of risk tolerance to maximize the use of its transmission assets while meeting customer needs.

We have already put in place or are considering the following transformational approaches:

- Available transmission capacity calculations will be modified to take a more risk-informed profile, potentially enabling greater sales on the existing transmission system.
- In alignment with FERC *pro forma* tariff and industry standards, BPA will review and may modify its commercial transmission products and services.
- New state awareness tools and use of generation redispatch together with increased operational connectivity with the California Independent System Operator will ensure more effective real-time monitoring. The incorporation of real-time data and analysis into the calculation of system limitations may release excess capacity while maintaining reliability. Enhanced visibility and control of loads, resources and flows (including market flows) will

allow more accurate, effective and reliable management of the transmission system.

- Non-wires measures to manage generation and loads to reduce peak congestion will launch this summer. We also will look to use cutting-edge grid technologies such as battery storage and flow control devices to proactively manage congestion and further extend operational capacity of the existing system.
- We will work closely with the region's other utilities, regional planning organizations and economic development organizations to convey the economic and operational implications of siting loads and generation resources in different areas. We will incentivize new load centers and resources to locate in areas that will make the best use of existing transmission capacity and minimize costs to them and to the region's electricity consumers.

The decision to not build the I-5 Corridor Reinforcement Project does not mean we and others will not need to build new lines in the future to provide additional transmission capacity in the Northwest. The region inevitably will need to build new lines, as well as rebuild existing, aging lines. But through this decision today, Bonneville is committing to taking a forward-looking approach with its investment decisions, and the region can be certain that BPA will seek first to use efficiencies and build at the smallest scale possible to meet our customers' needs, ensuring Bonneville remains a reliable engine of economic prosperity and environmental sustainability in the Northwest.

Understanding the certainty of business dealings our customers require, I want to reinforce Bonneville's commitment to offering terms and conditions of transmission service that align with FERC's *pro forma* tariff as much as possible; and indeed, we will be moving closer to that paradigm.

Work is already underway to craft solutions and design our way forward. Within a month, we expect to begin discussing these new approaches with our transmission customers and other stakeholders. During these discussions, Transmission Services will explain how we will advance our strategy and provide options for those seeking service across the South of Allston flowgate.

Thank you again for working with us as we take steps toward a more innovative transmission grid, updated business practices and improved regional coordination. This work is indicative of our commitment to working collaboratively with all of our stakeholders to deliver the best value for the region.

Sincerely,

/s/ Elliot E. Mainzer, May 17, 2017

Elliot E. Mainzer Administrator and Chief Executive Officer February 11, 2019

Organization: Renewable Northwest

IRP Topic(s) and/or agenda item(s): Feedback on transmission and the 2019 IRP

Comment:

Renewable Northwest and the NW Energy Coalition thank PGE for this opportunity to offer feedback as part of the 2019 IRP process. In these comments, we encourage the Company to explore a different treatment of transmission in its 2019 IRP compared to past IRPs.

We understand that, in preparing its IRP, PGE has relied, implicitly or explicitly, on the assumptions that transmission is available to deliver resources to PGE's system and that long-term firm ("LTF") transmission rights are available on neighboring systems. While those assumptions may have been appropriate in the past, they do not appear to be reasonable given the current transmission landscape.

Indeed, transmission constraints currently limit the ability of resources to deliver to PGE's system. Additionally, while PGE appears to prefer resources with LTF transmission (i.e. the 2018 RFP limited the eligibility of resources to those with—or that could soon obtain—LTF transmission rights), LTF rights to deliver to PGE over BPA's system appear to be scarce to non-existent. OPUC Staff found that such scarcity negatively impacted the number of viable bids in the 2018 RFP. (UM 1934, 12/4/18 Staff Report at 5-8)

In light of that transmission landscape, we encourage PGE to explore in the 2019 IRP the transmissionrelated issues that stakeholders raised at the December 19, 2018 roundtable. Specifically, Renewable Northwest and the NW Energy Coalition encourage the Company to:

- Model sensitivities where PGE assumes that future resources may deliver to PGE's system over "conditional-firm" transmission or similar transmission products. Resources using conditionalfirm transmission should be modeled under a variety of scenarios:
  - Use historical conditional-firm curtailment data from BPA and other relevant transmission providers to determine the expected impact to the delivered energy of a resource using conditional-firm transmission and any overall impacts on a particular portfolio identified in the 2019 IRP.
  - Run sensitivities on a set of curtailment assumptions (1%-5% of the hours in a year) for resources using hypothetical transmission products with such curtailment risk profiles.
     PGE should use the historical curtailment shape (month/day/hour of the year) and work with stakeholders to shape the timing and system impacts of these curtailment sensitivities.
- Identify the Company's existing transmission rights on BPA's system and consider how those transmission rights could be used to support a portfolio of resources, including the delivery of new resources that may meet needs that the Company identifies in the 2019 IRP.
  - For example, PGE could consider a new resource that brings transmission rights to Mid-C, but relies on PGE's existing transmission rights from Mid-C to PGE. In this scenario, PGE would be using their Mid-C-to-PGE transmission leg to facilitate delivery of power from either the Mid-C market hub, or this new resource, depending on the

## Attachment A: 2019 IRP Stakeholder Comment Record

circumstances for that hour. Such an approach would seem to use that transmission asset more efficiently by supporting multiple resources, but it could have an impact on the total deliverability and resource adequacy contribution from one or more of the resources using that same transmission leg. The tradeoffs between cost effective transmission use and delivered resource value can only be modeled as part of the IRP process.

 PGE should also consider options for redirecting existing firm transmission to new resources, on long-term or short-term basis, that may provide greater benefits to PGE's customers, for all or certain parts of year.

In summary, we encourage the Company to account for the impact that the current transmission landscape will have on the resources available to meet utility needs identified in the 2019 IRP. While we recognize that this request would increase IRP-team's workload, exploring these issues in the 2019 IRP is key to ensuring that this process results in a portfolio with the best combination of expected costs, risk, and uncertainties for PGE and its customers.

#### March 13, 2019

Organization: T.W. Sullivan plant neighbor

#### IRP Topic(s) and/or agenda item(s): Operating the T.W. Sullivan plant in the future

#### Comment:

With the mill closing in West Linn and the hydro plant only producing 18 MW I think it is time to close the plant and remove the dam and substation and power lines. The citizens of West Linn have endured this eyesore for 135 years. It is time to move out of the Willamette River. You pulled out of the Sandy River and it produced more power. You don't pay any property tax to West Linn or the County. I would like to know why you think it is important as you have stated to keep this plant in operation. If the plant shuts down and the dam and the fish ladders are removed we could have a new re-imagined Willamette Falls. I also think the locks should be removed as the river is not navigable per federal standards. I hope you reconsider your stance on keeping the plant in operation. I don't see an argument for keeping it after reviewing your website.

March 19, 2019

Organization: None

IRP Topic(s) and/or agenda item(s): Options for future generation

#### Comment:

I am happy to read that PGE is no longer considering new natural gas power plants at Carty. You are going to get by on more purchased hydro, wind, solar, and storage? If you haven't already, please check into Ambri and their liquid metal batteries. They might be the storage solution you need.

We live on the Pacific Ring of Fire; it is nutz that we don't use high-temp geothermal in the PNW. Carty is 135 air miles from the middle of PDX' main runway. Mt. St. Helens and Mt. Hood are both 46 miles away. How much would that reduce line losses? Yes, geothermal is expensive up front, especially if you do it right; but you don't have to buy a smallish power plant a train load of coal, or equivalent gas, every day, so over time it is supposed to be competitive. Iceland pipes steam miles to geothermal plants with

## Attachment A: 2019 IRP Stakeholder Comment Record

no appreciable heat loss. I see clearcut, on Google earth, within five miles of St. Helen's south rim, roads less than three miles away. I'm sure you could find an unobtrusive place to site a no-emissions geothermal plant where it wouldn't offend too many people.

But there might be a better, less expensive, way to power the foreseeable future. Are the turbines and generators etc. at Carty still serviceable, or refurbishable? More than one start-up in the U.S. is ready to build a molten salt fission reactor; you could demolish the coal boilers at Carty, replace them with reactors, and continue using the rest of your expensive equipment. The temperatures should be about right—MSRs run at around 700°C?—to just drop- in a couple of reactors the right size.

Five years ago—maybe even two yag—I'd have given you civil disobedience over the suggestion of building a new fission power plant anywhere in the PNW. I still would, should you consider any kind of pressurized water reactor. But I've done a lot of research since then. MSRs should be much safer: the ORNL model, at least, is designed so that a melt-down positively stops the reaction and renders the reactor safe; they operate at atmospheric pressure, so they are not steam explosions waiting to happen; they can continuously reprocess fuel, so far less dangerous material leaves and returns to the site, subject to accidental spill or terrorist theft; they can burn ~96% of their fuel, instead of the 4% a solid-fueled PWR burns before its fuel rods need reprocessing that we don't do, for fear of proliferation; and the best part is that they can burn up the 96% of the expensive fuel left in those solid-fueled PWR rods. This is how we solve our high-level radioactive waste storage problem. We have fuel for thousands of years already mined and in storage; no need/excuse for uranium miners to dig up Grand-Staircase Escalante and Bears Ears or any other national monuments. And all the fuel you would ever need is right up the river at Hanford.

I realize that selling nuclear power in the PNW would be an uphill battle. It would require public education; but I think that if you explain it as I did above, most people will understand. I was a Greenpeace volunteer 35 yag, and I've been a staunch no-nuker ever since. If you can sell molten salt fission to me you can sell it to anyone who thinks. I'm a technical writer; let me know if I can help with that. Meanwhile Bill Gates' TerraPower would love to build someone one of their reactors; I read that the DOE is urging them to build one in the U.S., while the NRC is in the way. Maybe our excellent congressional delegation could help with that. I would not recommend a Travelling Wave Reactor: they're cooled with liquid sodium, which explodes into flame on contact with air, and burns even more violently in water. But their Molten Chloride Fast Reactor sounds as safe as any fluoride salt reactor.

Or ThorCon would build you a copy of ORNL's MSR, in big modules they would ship/barge through Panama and up the Columbia to Boardman. Then you would need an Aeroscraft or Lockheed-Martin big lifter—250 or 500 tons—to fly the modules to the plant for you. Set up a tie-down system for the dirigible so that you can inch it side to side and back and forth, and it could lower the components exactly into place—no crane needed.

And find/create an industry there, to make use of your waste heat?

Were the turbines, generators etc. at Trojan demolished, or mothballed?

A coal plant at Centralia is shutting down next year, too? If you like this idea, please talk to them.

March 22, 2019

Organization: Renewable Northwest

IRP Topic(s) and/or agenda item(s): PGE's draft action plan

Comment:

Renewable Northwest thanks PGE for this opportunity to submit feedback on the Draft Action Plan that the Company unveiled at the February 27, 2019 IRP roundtable. We are generally supportive of the Draft Action Plan. However, we encourage PGE to provide additional details on the following items:

• Any differences that PGE anticipates between the cost-screen that PGE would use in its 2020 Renewables RFP and the cost-screen that PGE included in the 2018 Renewables RFP resulting from the 2016 IRP.

• Additional details on what technologies PGE considers would qualify for a potential "Non-Emitting Capacity RFP."

Renewable Northwest also encourages PGE to consider renewables paired with storage as a qualifying resource for any "Non-Emitting Capacity RFP" that the utility may issue.

Finally, Renewable Northwest appreciates PGE's intention to initiate a separate process to support the design of the next Renewables RFP. We encourage PGE to kick-start that process soon to help ensure a collaborative and productive RFP design and approval process.

March 22, 2019

Organization: National Grid and Rye Development

IRP Topic(s) and/or agenda item(s): Roundtable presentation 19-1

Comment:

Attached are PGE 2019 IRP Roundtable 19-1 Presentation comments from National Grid and Rye Development.

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March 22, 2019

Elaine Hart Integrated Resource Planning Manager Portland General Electric 121 SW Salmon St. Portland, OR 97204

RE: Roundtable 19-1 Presentation

Ms. Hart and PGE IRP Staff,

National Grid USA ("National Grid") and Rye Development, LLC ("Rye") appreciate the opportunity to present these comments on the February 27, 2019 Portland General Electric ("PGE") Integrated Resource Plan ("IRP") Roundtable 19-1 presentation (the "Presentation"). The Presentation demonstrates PGE's continued progress in developing a robust analysis for PGE's 2019 IRP, for which PGE should be commended, but PGE's IRP analysis should do more to evaluate the unique benefits pumped hydro storage has to offer PGE's customers.

PGE's preferred portfolio (referred to as the "Mixed Full Clean Portfolio" in the Presentation) recognizes some of the value pumped storage has to offer, but we believe PGE has more work to do on its modeling.<sup>1</sup> As National Grid and Rye have consistently noted in comments, pumped storage is invaluable in transitioning today's electricity grid to one that is increasingly reliant on renewable and intermittent sources of generation. Pumped storage is the most cost-effective resource that meets all of PGE's decarbonization goals, and is uniquely capable of providing PGE with reliable and dispatchable zero-emissions capacity that can replace the electricity and capacity services traditionally provided by fossil-fuel power plants. And unlike other shorter-duration energy storage technologies, pumped storage facilities have an extremely long useful life, offer unparalleled storage capabilities, and have minimal long-term environmental impacts.

National Grid and Rye appreciate PGE's work to date considering pumped storage as part of its IRP analysis, but the current analysis does not yet fully reflect the unique benefits presented by pumped storage. We offer the following comments on the Presentation to highlight a few key areas where additional analysis is warranted, and to provide information supporting an increase in the portion of pumped storage capacity in PGE's preferred portfolio.<sup>2</sup> We also suggest that PGE advance the timeline for its "Zero Carbon Capacity Procurement" Request for Proposals ("RFP") so that it will occur simultaneously with PGE's efforts to bilaterally acquire additional capacity from existing generation resources in the region. As explained below, advancing the

<sup>&</sup>lt;sup>1</sup> The Presentation at 84.

<sup>&</sup>lt;sup>2</sup> Attachment A (Evolved Energy Research, *Evaluation of Pumped Storage Projects in the Pacific Northwest* (Feb. 2018)).



RFP is both prudent from a utility-planning perspective, as well as imperative to acquiring capacity from longer lead time resources like pumped storage.

## The Preferred Portfolio Acknowledges the Value Pumped Storage Offers PGE's Customers

National Grid and Rye appreciate PGE's work evaluating pumped storage and are pleased to see pumped storage in the preferred portfolio. The inclusion of pumped storage is unsurprising given the fact that pumped storage facilities are safe, reliable, technologically straightforward generation assets with operating lifespans well over 100 years. This longevity, combined with low operating costs, means that pumped storage facilities benefit energy customers by providing long-term price stability, as well as the lowest levelized cost of energy among energy storage options. The large upfront capital costs associated with pumped storage projects are more than offset by the fact that these projects provide the greatest value to customers when complete life-cycle costs and benefits are considered.

In addition to having very long useful lives and low overall costs, pumped storage projects offer many reliability services that outperform other storage technologies considered by PGE. Given the acute need for grid-scale energy storage capability to reliably transition to a decarbonized generation fleet, PGE correctly included pumped storage in its preferred portfolio.<sup>3</sup> As PGE seeks to decarbonize its generation fleet and further integrate wind and solar generation resources, large, grid-scale storage becomes increasingly important to achieving these laudable decarbonization goals.<sup>4</sup> Because of the large amounts of storage capability needed to successfully integrate grid-scale wind and solar projects, pumped storage is ideally suited to balance the integration of these resources by providing a consistent, reliable, safe, and environmentally friendly source of storage capability that is unrivaled by any other storage technology.

## PGE Should Increase the Amount of Pumped Storage Capacity in its Preferred Portfolio Because the Current Analysis Does Not Include All of Pumped Storage's Unique Benefits

Given the numerous benefits pumped storage offers over other storage technologies, some of which are not captured in the modeling performed by PGE, National Grid and Rye suggest that PGE consider increasing the amount of pumped storage in its preferred portfolio. The preferred portfolio currently relies on roughly 250 MW of storage to meet PGE's future capacity needs, particularly beginning in 2024 and 2025.<sup>5</sup> A significant portion of this storage capacity is provided by four- and six-hour batteries. It is not clear why a four- or six-hour battery would be selected over a pumped hydro project that can offer more than nine hours of duration.<sup>6</sup> Taking

<sup>&</sup>lt;sup>3</sup> See Puget Sound Energy 2017 IRP at Ch. 6 at 6-54 (Nov. 14, 2017) ("With no new thermal resources available, the only resource large enough to meet capacity need is pumped storage hydro.").

<sup>&</sup>lt;sup>4</sup> See Utility Dive, California ALJ Proposes Statewide Renewable Energy Procurement for Utilities (Mar. 20, 2019), <u>https://www.utilitydive.com/news/california-alj-proposes-statewide-renewable-energy-procurement-for-utilitie/550839/</u> (reporting on a recent Californian administrative law judge's determination that combined IRP proposals of nearly 50 load serving entities would not collectively meet the state's greenhouse gas reduction goals and recommendation of a new procurement process that includes eight-hour duration storage).

<sup>&</sup>lt;sup>5</sup> The Presentation at 84.

<sup>&</sup>lt;sup>6</sup> Attachment A at 26 (showing max duration of Swan Lake at 9.5 hour and Goldendale at 12.3 hours).

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into account the full range of benefits, costs (financial and environmental), and services offered by the different types of storage resources, National Grid and Rye suggest that PGE reevaluate the allocation of capacity amongst storage resources in its preferred portfolio and strongly consider adding more capacity from pumped storage to its future resource mix. In particular, PGE should model replacing six- and/or four- hour batteries with pumped storage in the preferred portfolio. When the complete set of costs and benefits are considered, pumped storage is the most attractive storage technology, providing the greatest benefit to customers at the greatest value.

While each storage technology included in PGE's preferred portfolio may have a role to play in meeting PGE's future capacity needs, only pumped storage can provide economical, grid-scale storage to successfully integrate wind and solar resources while also providing the full suite of benefits that PGE would receive from any other large, grid-scale capacity resource such as a natural gas or coal facility. Specifically, and unlike other storage technologies, the pumped storage projects under development by National Grid and Rye are uniquely capable of offering PGE the following benefits and services:

- Meeting peak demand through longer duration discharge (nine to twelve hours) of stored energy, including during prolonged cold snaps;
- Providing grid reliability services commensurate with fossil fuel-fired power plants, such as primary frequency and voltage response;
- Absorbing unparalleled amounts of renewable generation, including during periods of overgeneration common in the Pacific Northwest spring runoff period;
- Facilitating the efficient transfer of large amounts of renewable energy between the Pacific Northwest and California, which is particularly valuable during periods of excess solar generation in California and negative energy pricing; and
- Maximizing the value of PGE's participation in the California Independent System Operator's Energy Imbalance Market by optimizing PGE's transmission capabilities.

These benefits are among the numerous reasons pumped storage outperforms any other storage technology. While PGE should be commended for their ongoing efforts to consider and evaluate all forms of storage technology to meet its future capacity needs, we believe work remains to be done on adequately capturing some of the unique benefits of pumped storage. Because these benefits have not yet been fully considered or quantified by PGE, National Grid and Rye believe PGE is still undervaluing pumped storage in its preferred portfolio. Thus, we request PGE carefully consider the full range of benefits each storage resource in its preferred portfolio can provide, and consider reallocating additional capacity to pumped storage.

# PGE's Analysis Doesn't Account for the Full Life-Cycle Costs and Risks of Each Type of Storage Resource Under Consideration

Just as additional work remains to be done in evaluating the full range of benefits pumped storage resources can provide, PGE also needs to further evaluate the full range of costs and risks associated with each storage technology under consideration in its IRP. To fairly evaluate each type of storage, PGE should consider the full range of costs and risks associated with each

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technology in order to create an "apples-to-apples" comparison. Otherwise, the costs of a pumped storage project will be unfairly inflated when compared to other technologies, thereby skewing the value proposition to the detriment of pumped storage.

First, although PGE's preferred portfolio relies significantly on four- and six-hour lithium-ion batteries, the analysis has not fully taken into account that lithium-ion batteries would need to be replaced multiple times during the lifespan of a pumped storage project.<sup>7</sup> PGE's analysis should acknowledge that lithium-ion batteries will have to be replaced at least three to four times over the course of 50-60 years, which is the minimum useful life of a pumped storage project. Doing so will accurately capture the true, and much greater, cost of battery storage relative to an equivalent amount of pumped storage over a similar timeframe.

Second, PGE should more fully consider the supply chain and environmental risks associated with battery storage technology. Due to the increasing demand for lithium and limited worldwide supply, there is likely to be future supply-chain risk associated with lithium-ion batteries that could substantially impact PGE's assumed cost for lithium-ion batteries. Furthermore, PGE's current cost-benefit analysis does not factor in the substantial environmental costs associated with extracting the raw materials needed to produce lithium-ion batteries, or the environmental impacts associated with the disposal of degraded lithium-ion cores, both of which can be significant as noted in recent articles.<sup>8</sup>

These kinds of full life-cycle costs and risks do not appear to be included in PGE's current analysis. Failure to consider these costs and risks may result in imprudent assumptions that could hinder PGE's ability to procure cost-effective capacity to meet its customer's needs.

### PGE Should Match the Timeline of its "Zero Carbon Capacity Procurement" RFP With the Timeline for Acquiring Other Capacity from the Market and Consider Both Options Contemporaneously

National Grid and Rye believe PGE should conduct its RFP simultaneously with its effort to secure capacity from existing resources. Doing so would be prudent planning and ensure that resources PGE intends to rely upon in the future are actually available when needed. PGE's

<sup>&</sup>lt;sup>7</sup> To the extent that pumped storage plants have demonstrated lifetimes longer than the period assumed for levelization, batteries would incur additional replacement costs to provide an equivalent service life. Additionally, pumped storage can cycle more than once per day if needed to meet morning and evening peaks, whereas batteries would degrade faster and incur higher replacement costs than assumed by PGE if cycled more than once per day; *compare* Northwest Power and Conservation Council, *White Paper on the Value of Energy Storage to the Future Power System* (Nov. 2017), <u>https://www.nwcouncil.org/sites/default/files/2017-8.pdf</u> (noting lithium-ion batteries have a useful life of approximately 10,000 cycles when used for bulk energy storage applications, which assuming just two cycles per day, equates to a total useful life of approximately 13.5 years) *with* HDR, *Thermal and Pumped Storage Generation Options* at 49 (Oct. 4, 2018) (noting that pumped storage facilities can be expected to last at least 50 years, with many of the facilities constructed in the 1920's and 1930's still in operation today).

<sup>&</sup>lt;sup>8</sup> *E.g.*, WIRED on Energy, *The Spiraling Environmental Cost of Our Lithium Battery Addiction* (Aug. 5, 2018), <u>https://www.wired.co.uk/article/lithium-batteries-environment-impact</u> (noting lithium and other battery material mining is particularly damaging to the environment; and suggesting that only 3% of the lithium from batteries is able to be recycled requiring high-energy and expensive processes in order to extract reusable lithium).

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Draft Action Plan suggests that it intends to pursue a "staged procurement process" that would focus on securing "cost competitive existing capacity in the region via bilateral negotiations" before conducting the RFP in 2021 to fulfill any capacity needs that remain.<sup>9</sup> Conducting the RFP at the same time PGE pursues capacity through bilateral negotiations would be the most prudent way for PGE to evaluate the capacity market as a whole and make the best decisions about which set of resources will most cost effectively meet its future capacity needs. Having the benefit of responses to the RFP while evaluating offers to sell capacity from existing resources would give PGE the added benefit of having complete market information in order to make more informed decisions.

Additionally, PGE's reliance on future cost-effective capacity acquisitions may not be realistic. Considering that PGE has demonstrated capacity needs throughout much of the next decade,<sup>10</sup> and that Bonneville Power Administration ("BPA") will also be seeking to renegotiate its wholesale power contracts during this same time period, capacity purchases offered by BPA will most likely only be for limited durations, and may become more speculative as the deadline for renewing its wholesale power contracts approaches. Delaying its capacity RFP may subject PGE to increased price risk and diminished options to acquire the capacity needed to meet PGE's future needs.<sup>11</sup> As such, National Grid and Rye recommend PGE conduct the RFP and the capacity procurement simultaneously. That will afford PGE additional optionality to meet its capacity needs, and provide a hedge against the very real risk that the capacity market does not materialize as PGE appears to expect.

Finally, the practical reality associated with the timelines to construct large grid-scale storage resources also favors an earlier RFP. If PGE expects to rely on any such resources to meet even a portion of its future capacity need, then procurement decisions need to be made well in advance of when that capacity is actually needed. Waiting until 2021 to conduct an RFP leaves insufficient time to complete the development process for a large grid-scale storage resource. While National Grid and Rye's pumped storage resources have the benefit of being relatively far along in the permitting and development process, a 2021 RFP may create an unfeasible development timeline that favors short-term market purchases. Therefore, to avoid effectively precluding all types of storage resources from participating in the RFP, it is imperative that PGE advance the timeline for the RFP to coincide with PGE's other efforts to purchase capacity from existing regional resources.

## Conclusion

PGE's consideration of pumped storage in its IRP to date is commendable, but given the unique benefits these resources can provide, a more robust analysis must be conducted to fully consider the costs and benefits of various energy storage technologies. While National Grid and Rye appreciate PGE's stated intention to rely on pumped storage to meet a portion of its future capacity needs, we caution that in order to ensure pumped storage capacity is available when it is

<sup>&</sup>lt;sup>9</sup> The Presentation at 91.

<sup>&</sup>lt;sup>10</sup> *Id.* at 9.

<sup>&</sup>lt;sup>11</sup> A constrained capacity market could also result from increased load growth, economy-wide electric vehicle adoption, local carbon legislation, low water, or any host of unknown factors.
#### Rye Development



expected to meet PGE's capacity needs, PGE's RFP should be advanced and conducted simultaneously with its efforts to acquire capacity from existing resources in the region.

Please let us know if you have any questions about our comments. We would be happy to discuss them further with you.

Sincerely,

Note Andrig

Nathan Sandvig Director, US Strategic Growth National Grid Ventures <u>Nathan.Sandvig@nationalgrid.com</u>

Enclosure

Erik Steimle V.P. Project Development Rye Development, LLC Erik@ryedevelopment.com

# Evaluation of Pumped Storage Projects in the Pacific Northwest



# EVOLVED ENERGY RESEARCH

**Prepared For:** National Grid and Rye Development

**Prepared By:** Gabe Kwok Jeremy Hargreaves

February 2018

#### **DRAFT REPORT FOR REVIEW**

#### Contents

- Background and Context
- Study Assumptions and Approach
- Scenarios and Sensitivities
- Modeling Results
- Discussion





## Background and Context

**Confidential and Deliberative Draft** 

## Background

- Evolved Energy Research (EER) was engaged by National Grid and Rye Development to study the value of the Swan Lake North ("Swan Lake") and Goldendale Energy Storage ("Goldendale") pumped storage hydropower (PSH) projects
- Both projects utilize "closed-loop" technology and are situated in the Pacific Northwest
  - Swan Lake is a 400 MW project located in southern Oregon
  - Goldendale is a 1,200 MW project located in southern Washington



#### Context

- The Pacific Northwest resource mix is expected to undergo significant changes over the coming years due to technology and policy drivers
  - Planned retirement of coal-fired resources
  - Increase in Oregon's renewable portfolio standard (RPS) to 50% by 2040
  - Proposal by Washington Gov. Inslee to obtain 100% clean electricity by 2045
  - Economy-wide carbon goals would further affect the electricity sector
  - California's 100% clean electricity policy is also expected to have impacts on the Northwest and across the Western Interconnection
- These changes point to an increasingly decarbonized and renewable electricity grid, which will challenge the system's ability to balance supply and demand across all time horizons (minute to minute; hour to hour; and season to season)

## Purpose and Approach

- Pumped storage hydro (PSH) becomes increasingly valuable in a decarbonizing electricity system, because intermittent renewables drives a need for the flexible grid services PSH can provide:
  - Balancing the system;
  - Shifting energy from times of excess to times of need; and
  - Providing resource adequacy, thus avoiding investment in alternative resources
- The purpose of this study is to investigate whether PSH is part of a least cost resource solution to meet the policy goals of the Pacific Northwest
- To do so, we simulated electricity sector operations and investment across a variety of scenarios to identify conditions where the PSH projects are most valuable





Study Assumptions and Approach

**Confidential and Deliberative Draft** 



## Modeling Framework

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#### Overview

- This study utilizes the Regional Investment and Operations (RIO) planning model, developed by EER, to assess the value of the Swan Lake and Goldendale pumped storage projects
  - RIO is a least cost capacity expansion model designed to credibly simulate operations and investment decisions in electricity systems with high renewable penetrations
- We use RIO to produce resource portfolios and model system operations for regions of the Western Interconnection from 2020 through 2050
- While other capacity expansion planning and evaluation studies have focused on one balancing authority (BA) or region with less detail in surrounding areas, this study explicitly models both the Pacific Northwest and California, such that investments in one region impact those in the other



## Regional Investment and Operations Platform (RIO)

- Produces least-cost resource portfolios subject to capacity, energy, emissions, RPS and technology availability constraints
- Simulates sequential hourly system operations for each year
  - Hourly dispatch ensures sustained peaking capability of energy-limited resources such as hydro is captured
  - RIO uses a subset of days within a year to model system operations
- Incorporates long-duration energy storage resources
  - Energy can move between sampled days
  - Necessary at high renewable penetrations, or excessive curtailment and overbuild of resources is realized



Load, Hydro and Renewables

- Weather-driven or seasonal trends in load, hydro availability and renewable production cause operational challenges that can persist over long periods
- In order to capture a range of electricity system operating conditions, we incorporate load, wind, solar and hydro profiles from multiple weather years
  - Load, wind and solar: hourly profiles are from the 2010, 2011 and 2012 weather years
  - Hydro: dry, normal and wet hydro conditions from 2001, 2005 and 2011 are represented, respectively



#### **Optimal Hourly Operations and Long-Term Storage Behavior**

RIO models short-term operations over sample days & long-term storage across every day of the year



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## **Planning Reserves**

- Planning reserve margins are used as a proxy for meeting resource adquacy
   Defined as [sum(resources) / median peak load 1]
  - Typical industry margins vary from 10% to 15%
- This process works well in systems where resources are primarily dispatchable and nameplate roughly equals the contribution of that resource to reliability (e.g., systems that primarily consist of thermal resources)
- However, this is more challenging in systems dominated by energy-limited (hydro; energy storage) and non-dispatchable (wind; solar) resources
- Alternatively, RIO enforces a capacity reserve constraint across all model hours that accounts for the contributions of these resource types



## Hourly Planning Reserve Constraint

- Planning reserve requirement in each zone must be met or exceeded in every hour by the supply of resources that are adjusted by their dependability
- Reserve requirement
  - 107% of gross load representing weather-related risk of load exceeding that sampled

#### • Reserve supply

- <u>Thermal</u>: derated\* nameplate
- Hydro: derated hourly output
- <u>Renewables</u>: derated hourly output
- Energy storage: derated hourly discharge minus charge
- Imports: derated net flows
- \*All resources are given a resource-specific derate representing forced outage rates, energy limited risk and weather related risk





#### **Overview**

- Operations and investment are simulated across four zones
  - 1. Pacific Northwest (PNW)
  - 2. California ISO (CAISO)
  - 3. Non-CAISO California
  - 4. Rest of WECC
- These four study zones comprise multiple balancing authorities across the WECC



## Mapping Balancing Authorities to Zones



Source: image from WECC

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Study Zone	Balancing Authorities
PNW	<ul> <li>Avista (AVA)</li> <li>Bonneville Power Administration (BPA)</li> <li>Chelan County PUD (CHPD)</li> <li>Douglas County PUD (DOPD)</li> <li>Grant County PUD (GCPD)</li> <li>PacifiCorp West (PACW)</li> <li>Portland General Electric (PGE)</li> <li>Puget Sound Energy (PSEI)</li> <li>Seattle City Light (SCL)</li> <li>Tacoma Power (TPWR)</li> </ul>
CAISO	California Independent System Operator (CAISO)
Non-CAISO CA	<ul> <li>Balancing Authority of Northern California (BANC)</li> <li>Imperial Irrigation District (IID)</li> <li>Los Angeles Department of Water and Power (LDWP)</li> <li>Turlock Irrigation District</li> </ul>
Rest of WECC	<ul> <li>Includes remaining BAs shown on the map</li> <li>Excludes BAs in Canada and Mexico</li> </ul>

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## Topology

- Capacity values are derived from major WECC transmission path ratings

   Capability between PNW and California zones reflects allocation of PDCI and COI
- Simultaneous net export constraint from CAISO is also implemented
  - Base values are from CPUC IRP: 2,000 MW today and rising to 5,000 MW by 2030





## Load Projections

- Load projections for the PNW zone are derived from the Pacific Northwest Utilities Conference Committee (PNUCC) <u>2018 Northwest Regional Forecast</u>
   Load projections are net of energy efficiency
- Projections for the two California zones are derived from the California Energy Commission (CEC) <u>2017 Integrated Energy Policy report (IEPR) Mid Demand</u> <u>Baseline Case</u>



## Load Shapes

- Hourly load shapes for each zone are based on historical load for balancing authorities in each zone from 2010 through 2012
  - Historical data is from FERC Form No. 714
- Balancing authority loads are aggregated and scaled to future demand





### **Baseline Resources**

- Baseline resources include:
  - 1. Existing resources;
  - 2. Planned retirements of existing resources; and
  - 3. Planned additions
- This study utilizes WECC's <u>Anchor Data Set (ADS)</u> to project baseline generation resources for each zone
  - ADS is a compilation of resource information across the WECC through 2028
  - Includes operating characteristics for each resource, such as minimum and maximum capacity, heat rate, ramp rates, etc.
- Resources are assumed to stay online throughout the study horizon unless they have a specified retirement date
  - The existing hydro and nuclear capacity in the PNW is constant through 2050

## Hydroelectric System

- The Pacific Northwest's hydroelectric system includes more than 30 GW of capacity, but its operational flexibility and generating capability varies year-to-year
- We model each study zone's hydro resources as an aggregated fleet and apply constraints based on historical operations
- Operational constraints for regional hydro fleets are derived using hourly generation data from WECC for 2001, 2005 and 2011, which represent dry, average and wet hydro years, respectively
  - Operational constraints vary by week of the year (1 through 52) and hydro year (dry, average and wet)

#### **Historical Generation Data by Plant**



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### **Renewable Resources**

- Candidate onshore wind and solar resources
  - State-level resource potential, capacity factor and transmission costs are derived from <u>NREL's Regional Energy Deployment System</u>
  - Capital cost projections are from NREL's Annual Technology Baseline 2018
- We incorporate hourly profiles for wind and solar resources throughout the WECC for weather years 2010 through 2012
  - Wind profiles are from NREL's Wind Integrated National Dataset (WIND) Toolkit
  - Solar profiles are derived using data from the NREL <u>National Solar Radiation</u> <u>Database</u> and simulated using the <u>System Advisor Model</u>



## Energy Storage: Pumped Hydro Projects

- We model the Swan Lake and Goldendale projects for selection in the PNW zone using the cost and performance inputs outlined below
- In addition, we allow up to 2,000 MW of new pumped storage in California using the Swan Lake characteristics as a proxy

Project	Capacity (MW)	Max. Duration (hours)	Earliest Online Year	Capital Cost (\$/kW)	Fixed O&M (\$/kW-yr)
Swan Lake	400	9.5	2025	\$2,000	\$28.3
Goldendale	1,200	12.3	2028	\$2,143	\$12.5

ARE THE COSTS CONFIDENTIAL?



**Energy Storage: Batteries** 

- Two battery storage resources are modeled
  - 1. Lithium-ion
  - 2. Vanadium Flow
- Base cost projections are derived from the International Renewable Energy Agency (IRENA) <u>Electricity Storage and Renewables:</u> <u>Costs and Market to 2030</u> report
- This includes separate cost projections for the capacity (\$/kW) and energy (\$/kWh) components of the storage system and RIO selects the optimal duration of new resources over time



#### Gas Resources

- RIO can select from four gas-fired resource alternatives
  - Frame combustion turbine (CT)
  - Aero CT
  - Reciprocating engine
  - Combined cycle (CC)
- Cost and performance characteristics for new gas resources are from Portland General Electric's Integrated Resource Plan
- Fuel price projections for natural gas delivered to generators is derived from the EIA's <u>Annual Energy Outlook 2018 Reference Case</u>
  - Natural gas prices increase modestly from today in real terms (e.g., \$5/MMBtu in 2017 dollars)



#### **Demand Response**

- We model the demand response (DR) resources from the Northwest Power and Conservation Council's <u>Seventh</u> <u>Power Plan</u>
- Since the DR resources from the Seventh Power Plan encompass a larger geography, we de-rate potential by the load-ratio share of the PNW study zone
- This results in approximately 1,600 MW of DR by 2035





#### Overview

- We evaluated the value of pumped storage across a range of scenarios including alternative mechanisms to decarbonize the PNW's electricity sector
  - Placing limits on CO<sub>2</sub> emissions from the electricity sector
  - Limiting the development of new gas-fired resources
- In addition, we evaluated the sensitivity of pumped storage selection to a variety of alternative assumptions, including battery energy storage costs, availability of biogas and power-to-gas technologies, coal retirements, regional transmission and natural gas prices



# Summary of Scenarios

Category	Scenario	Description	
Baseline	Baseline	Reflects current policy and excludes any new decarbonization policy	
New Gas Resource Constraints	Limited New Gas	Up to 2,000 MW of new gas resources are allowed	
	No New Gas	No new gas resources are allowed	
Emissions Cap	80% Reduction	Electricity sector emissions are constrained to 80%,	
	90% Reduction	90%, 95% or 100% below 1990 levels by 2045	
	95% Reduction		
	100% Reduction		



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### **Emissions Cap Scenarios**

- These scenarios place a limit on CO<sub>2</sub> emissions from PNW electricity generation Combined OR and WA emissions were 33.5 million metric tons (MMT) in 1990 and 36.5 MMT in 2013
- The year 2045 was chosen to achieve emissions reductions for a variety of reasons:
  - Proposed legislation by WA Governor Jay Inslee seeks to eliminate fossil fuels from electricity generation by 2045
  - 2045 aligns with California's 100% clean electricity requirement (SB 100)
  - Expectations exist that the electricity sector will decarbonize more quickly and deeply than other sectors in order to achieve economy-wide decarbonization



#### PNW Emissions Cap in 2045

## Sensitivity Analysis

- We evaluated the sensitivity of pumped storage selection to a variety of alternative assumptions, including:
  - Lower battery energy storage costs
  - Availability of biogas
  - Including flexible electric fuel production (e.g., power-to-gas)
  - Transitioning from coal-fired electricity generation by 2025
  - Enhanced utilization of transmission interties between PNW and California
  - Higher natural gas prices
- These sensitivities were undertaken on the 100% Reduction scenario


### **Baseline Scenario: Overview**

- Without policies in place to decarbonize the PNW electricity sector, gas-fired power plants are the principal resource to meet most energy and capacity needs through 2050
  - Incremental wind and solar resources are added to meet existing RPS policy
- No energy storage resources are developed



## 80% and 90% Reduction Scenarios

- Policies to explicitly cap carbon emissions incentivize renewable and energy storage development and disincentivize gas resources
- Energy storage is not selected until emissions are capped at 90% below 1990 levels by 2045
- Pumped storage build does not occur until the 2040s due to factors including:
  - Planned retirement of coal resources make up a large portion of early emissions reductions
  - Emissions cap is not stringent enough until the 2040-2045 period to severely limit gas plant build and operations





## 95% and 100% Reduction Scenarios

- Swan Lake and Goldendale are fully developed by 2045 under the 95% Reduction scenario
- Further reducing emissions from 95% to 100% below 1990 levels by 2045 results in:
  - Goldendale build beginning in 2035
  - Selection of approximately 6,500 MW of battery energy storage by 2050
  - A total of 2,400 MW of new gas built with the last plant online in 2035



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### New Gas Resource Constraints

- Constraints on developing new gas resources result in new energy storage and renewable resources to meet capacity and energy needs
- In the No New Gas scenario, Swan Lake and Goldendale are both fully selected by 2035 and are supplemented by battery energy storage resources
- Both scenarios include an extensive buildout of wind and solar resources beyond existing RPS policy to provide both energy and marginal capacity benefits



# Summary of Energy Storage Resource Selection

# Cumulative New Build: Energy Storage Capacity $_{\mbox{\tiny MW}}$



### Average Energy Storage Duration Increases with Decarbonization

- Capping or eliminating electricity sector emissions increases the average duration of new energy storage resources
  - Thermal resources are limited by how often they operate, which necessitates wind and solar generation to be delivered to load
- Average duration approximately doubles from 12 to 24 hours as emissions reductions increase from 90% to 100% below 1990 levels
- Not all resources are required to match the average duration, and it's plausible to have a mix of resources with alternative durations to alleviate different challenges (e.g., 4-hr energy storage for transmission constraints; 36-hr for renewable integration)





# Sensitivity Analysis

Confidential and Deliberative Draft



# Availability of Biogas

- This sensitivity explores the availability of net-zero-carbon biogas, which would allow gas-fired resources to continue operations in 2045 and beyond
- The supply of sustainable bioenergy is limited and may be used to produce other biofuels (e.g., renewable diesel) instead of biogas
- Our sensitivity analysis explores a range of 25 to 50 TBtu of biogas availability
  - Allows approximately 450 to 900 aMW of generation from a new combined cycle
  - For context, gas-fired resources in Oregon and Washington consumed approximately 200 TBtu of natural gas in 2016



## Impact of Biogas Availability

- Allowing gas-fired resources to burn zero-carbon biogas primarily decreases battery energy storage build
- Overall renewable build decreases with approximately 3,500 MW fewer wind and 2,000 MW fewer solar resources when 50 TBtu of biogas is available



## Power-to-Gas Technology

- This sensitivity explores the availability of power-to-gas (P2G) technology
- P2G technology competes with energy storage resources by: (1) operating as a flexible demand that consumes renewable generation; and (2) producing carbon-neutral fuel (e.g., synthetic natural gas) for gas-fired power plants to continue operations
  - One of the key uncertainties about P2G is that the benefits they provide to electricity balancing is contingent on there being a market for the electric fuels they produce
- Our sensitivity analysis explores a range of up to 2,000 to 3,000 MW of P2G facilities



### Impact of Power-to-Gas

- The availability of flexible electric fuel production significantly reduces energy storage needs in a 100% clean electricity system
  - 2,000 MW of P2G displaces all battery energy storage and 400 MW of PSH
- Volume of synthetic natural gas produced by P2G allows gasfired resources to generate between 600 and 750 aMW in 2050



### Lower Battery Costs

- Our base battery costs assume aggressive cost reductions through 2030 and then constant thereafter
  - Follows projected reference costs from IRENA's *Electricity storage and renewables: Costs and markets to 2030* report
- The low battery cost sensitivity assumes costs continue to aggressively decline through 2050
  - 2050 value is based on the most optimistic scenario from the same report



### Lower Battery Costs

- Assuming lower-cost trajectory for battery energy storage resources results in two primary differences:
  - Pumped storage build is delayed until 2045
  - The composition of battery storage resources shifts entirely to lithium-ion



EVOLVED ENERGY RESEARCH **Higher Natural Gas Prices** 

- This sensitivity explores the impact of increased natural gas prices on pumped storage value
- We use the "Low oil and gas resource and technology" case from the EIA's Annual Energy Outlook 2018 as the basis for the sensitivity
- We did not consider a low natural gas price sensitivity, because base projections are already near historic lows



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## **Impact of Higher Natural Gas Prices**

- Higher natural gas prices, reaching \$7/MMBtu in 2035 and \$9/MMBtu in 2050, accelerate pumped storage development
- 750 MW of Goldendale is online by 2035 versus 150 MW under base assumptions



Coal Transition by 2025

- Sensitivity assumes the PNW zone is coal-free by 2025, including local coal resources and "coal-by-wire" from outside Oregon and Washington
  - This is consistent with Gov. Jay Inslee's proposal to transition Washington State to 100% clean energy
  - Oregon's existing Clean Electricity and Coal Transition Plan already requires investorowned utilities to transition from coal by 2030
- This results in an acceleration of energy and capacity needs in the near-term



## Coal Transition by 2025

- Eliminating coal-fired generation from the resource mix by 2025 results in higher near-term gas build
  - Includes a combination of gas
     CC and CT resources
- Overall energy storage build over time is unaffected



# Enhanced Utilization of PNW-CA Transmission Interties

- This sensitivity explores the impact of better utilizing transmission interties between the Pacific Northwest and California
- Currently, there are constraints, such as CAISO's simultaneous net export limit and wheeling charges, that inhibit flow of power
  - The importance of these constraints increases as California seeks to achieve 100% clean electricity and it's expected surplus solar generation could be exported to neighboring regions (e.g., PNW)

Category	Base Assumption	Enhanced Utilization
	2018: 2,000 MW	2018: 2,000 MW
CAISO Net Export Limit	2030: 5,000 MW	2030: 8,000 MW
	2050: 5,000 MW	2050: physical limit
CA-PNW Hurdle Rates	Maintain through 2050	Remove in 2030



### **Enhanced Utilization**

- The primary impact of enhanced utilization is an overall reduction in PNW resource build to achieve emissions reductions goals
  - Batteries: -1,100 MW
  - Solar: -4,000 MW
  - Gas CT: -1,200 MW





## **Operational Considerations**

# **Operational Considerations of Energy Storage**

- Concerns have been raised about the ability of storage resources to provide grid services during challenging power system conditions in the Pacific Northwest, such as extended periods of high load, low hydro and minimal wind output in the winter
- The primary concern is that several consecutive days of low wind and solar generation would provide insufficient energy to charge storage, therefore limiting its capability to discharge
- Two expected changes across the electricity sector could potentially manage challenging operating conditions and address concerns about energy storage
  - 1. California's 100 percent clean electricity requirement would provide an ample supply of excess clean energy that could be exported over existing interties during the winter
  - 2. The incremental renewable development required to decarbonize the PNW electric sector would likely be more diverse in terms of both geography and technology



### Excess Renewables in California May Be Exported to PNW

- Our modeling shows that California's 100 percent clean electricity requirement results in significant amounts of excess renewable generation during the winter when loads are low
- This could potentially be exported over *existing transmission* (i.e., flow south-to-north over COI and PDCI) and provide energy for storage to recharge



Exhibit V-3 Page 6 of 6

OREGON

PDCI

NEVADA

# Importance of Pacific Northwest-California Interties

- Interties between the Pacific Northwest and California have long played an important role to share surplus energy
- As both regions transition towards low-carbon electricity systems, existing interties could be effectively utilized to manage overgeneration originating in either region
- Excluding the existing capability and the dynamics occurring across the Western Interconnection (e.g., California's 100% clean requirement) will result in excessive curtailment and overbuild of resources to achieve the same emissions target
- Furthermore, better utilization of the interties, as illustrated in the Enhanced Utilization sensitivity, or expanding interties provides economic benefits by reducing the overall infrastructure needed to achieve the same policy targets and producing more cost-optimal resource portfolios



### Renewable Diversity

- Today, renewable resources in the PNW are predominantly wind plants located in the Columbia River Gorge
- The lack of geographic diversity means that zero or low generation events are more frequent than in other regions
  - An often cited event is January 2009 where there was zero wind generation for more than a week in BPA's balancing authority
- The low-carbon scenarios evaluated in this study require significantly higher renewable penetrations than today, with approximately 40 to 50 GW of wind and solar by 2050
- This level of renewables would be more diverse than today
  - Wind development outside of the Columbia River Gorge
  - Wind development in other states (e.g., Montana)
  - Significant levels of solar, which is minimal today

### Map of Existing Wind and Solar Plants



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ENERGY

## **Regional System Operations: Winter 2045**

95% Reduction Scenario

- Electricity system

   operations evolve as both
   the PNW and California
   decarbonize their electricity
   sectors
- During the winter when PNW operations are most stressed from high loads and low hydro, excess renewable generation in CAISO is exported to PNW



## **PNW Pumped Storage Operations: Winter 2045**

95% Reduction Scenario

 This dynamic allows pumped storage in the PNW to charge during the winter on carbon-free electricity and generate during peak hours



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### Pumped Storage Resources Contribute To Maintaining Reliability

### 95% Reduction Scenario

System reserve requirement is met by energy-limited resources (hydro; storage) and non-dispatchable resources (wind; solar)



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### PSH Reserve Contribution

Pumped storage significantly contributes toward system reserves, particularly during the morning and evening peaks





# Drivers of Pumped Storage Value: Carbon Emissions Cap

- The primary mechanism to incentivize the development of pumped storage in the Northwest is capping or eliminating carbon emissions from the electricity sector
- In these scenarios, the PNW electricity sector is largely decarbonized through new wind and solar resources, which causes a mismatch between supply and demand
  - Pumped hydro can help balance the system and avoid additional investment
- We investigated other solutions that can offer similar grid services:
  - Gas-fired resources using biogas as a fuel reduces the need for battery storage, but pumped storage is still part of a least cost solution by 2045
  - Power-to-gas significantly displaces overall energy storage build
- Longer-duration storage resources such as pumped hydro and power-to-gas are valuable assets in reaching decarbonization goals at least cost



# Drivers of Pumped Storage Value: Constraints on New Gas Build

- The significant hydro resource in the PNW means that emissions from gas are proportionally small, and decarbonization policy is not stringent enough to limit gas build and operations until later years
  - However, building new gas even today has proven a challenge in the PNW
- If opposition to gas were to limit new build, cost effective pumped hydro would be accelerated
- Furthermore, if expectations about future natural gas prices increase above our base case assumptions, then pumped hydro build is accelerated



# Assumptions Affecting Timing and Magnitude of PSH Build

- The economic selection of pumped storage in this study may be affected by conservative assumptions
- First, we evaluated the role of pumped storage in a least-cost portfolio for the Pacific Northwest region rather than individual utilities or balancing areas
  - This may overstate system flexibility by aggregating resources across multiple balancing authorities and individual balancing authorities may find it harder to balance their systems with very high renewable penetrations
  - Utilities across the region face different load-resource balances which may affect the timing of resource decisions
- Second, we assume all of the demand response potential from the Northwest Power and Conservation Council's Seventh Plan is implemented
  - There are ongoing concerns about all of the DR potential being acquired and the primary impact is deferring the selection of other capacity resources until future years



# Thank You

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### Attachment A: 2019 IRP Stakeholder Comment Record

March 22, 2019 Organization: OPUC IRP Topic(s) and/or agenda item(s): 2019 IRP draft action plan Comment: Attachment



SUBJECT:	Informal Feedback on Draft Action Plan for 2019 IRP
FROM:	Oregon Public Utility Commission, Energy Resource & Planning Division
TO:	Portland General Electric IRP Team
DATE:	3/22/19

Oregon Public Utility Commission (OPUC or Commission) Staff appreciate the opportunity to provide early informal feedback to Portland General Electric (PGE or Company) on the Draft Action Plan found in their February 27, 2019 IRP PowerPoint (Roundtable 19-1). Staff's comments are organized into two sections. The first section provides direct responses to PGE's action plan, as requested by the Company. The second section provides more general comments and feedback on the 2019 IRP that did not necessarily fit within the context of responses to the Draft Action Plan.

### Section 1, Feedback on the Draft Action Plan

### 1.a. Acquire all cost-effective energy efficiency

Staff is supportive of this Action Item.

### 1.b. Acquire all cost-effective distributed flexibility

• Staff is supportive of this Action Item.

### 2. Conduct renewables request for proposal (RFP) in 2020 for 150 aMW

Staff has concerns about PGE's need to issue another RFP for renewable resources as early as 2020. Staff was somewhat surprised as PGE's revised renewable action plan from 2017 and most recent 2018 IRP roundtable PowerPoint, do not identify additional renewable resources until as early as 2022.<sup>1</sup> To this end the most recent analysis does not entirely comport with the information Staff and stakeholders had received previously. While Staff understands this can happen, as analysis comes into sharper relief, the outcome raises concerns about the underlying analysis. PGE notes that portfolios containing renewable acquisitions as early as 2023 do "perform best." But the evidence provided thus far in the form of graphs seem to overly focus on the previously, well-known issue of the production tax credit (PTC) dropping from 60% to 40% at end of 2022.<sup>2</sup>

Staff and will look to the IRP to provide much more information to justify this action before we can support this Action Item

<sup>&</sup>lt;sup>1</sup> See PGE Revised Renewable Action Plan Item, November 19, 2017, pg. 18 *and* PGE 2019 Integrated Resource Plan, Roundtable18-6, November 28, 2018, pg. 34.

<sup>&</sup>lt;sup>2</sup> See PGE 2019 Integrated Resource Plan, Roundtable19-1, February 27, 2019, pg. 82.

Staff is also flummoxed by the very limited discussion in the analysis to-date of crucial items that would be needed to support the Renewable RPS Action Item, such as the interplay with PGE's REC bank and the Company's overall renewable resource sufficiency period. These crucial concepts are only implicitly addressed in the draft action plan in so far as the Company would be willing to "return the value of RECs generated prior to 2030."<sup>3</sup>

To this end, Staff would note that we have yet to engage with the Company on how to best "return the value" of the renewable resources PGE just acquired, under Order 18-044, let alone an additional 150 aMW as proposed.

In LC 66 the Commission thoughtfully addressed the difficult challenge of balancing future needs against near-term risks and opportunities, notably reminding stakeholders, "...not to view the IRP guidelines as pre-established checklists but rather to proactively adapt their assessment of risk and uncertainty as industry evolution comes into greater focus."<sup>4</sup>

Based on what Staff has been presented with thus far, Staff feels the Commission's encouragement to be proactive and adapt, as embodied in this Action Item, is mostly likely being taken too far by PGE. Before Staff can support *another* near-term, large-scale resource acquisition PGE would have to greatly expand on the limited data presented regarding renewable need in the near- to medium- term, both within and outside the concept of a "glide path." Staff would also like to better understand how this Action Item and PGE's RPS would be impacted by the State's proposed Cap-and-Trade system.

In addition, Staff sees a need to have a much deeper discussion about how to better model and actually leverage the proposed new capacity found in PGE's QF queue to meet long-term RPS needs. Staff would also like a much better understanding of load forecasts (that should include absolutely no direct access load), projected renewable costs, and transmission, especially given the complementary timeframe between RPS compliance and the long-life of transmission resources.

Staff would also assert that PGE would most likely have to bring forth new and persuasive data if PGE would seek to justify this IRP's proposed renewable RFP based on just an economic opportunity. The existence of the PTC at the 60% level and some attendant level of economic benefit does not seem compelling in and of itself, especially given what appears to be a limited need in the next decade

Finally, per Order 18-044 Staff was under the impression that PGE's development of a glide path analysis would be a part of the IRP, i.e up for discussion; Staff and stakeholders would have chance to provide input towards the development, application, and finally acknowledged glide path. Instead, PGE appears to be treating this important tool as an internally developed output, driving resource acquisition decisions with Staff and stakeholders left to debate the merits of the output and not the glide path's development and underlying assumptions. We would like to address this prior to or within the 2019 IRP.

### 3. Staged procurement of more capacity

<sup>&</sup>lt;sup>3</sup> *Ibid*, pg. 90.

<sup>&</sup>lt;sup>4</sup> See LC 66, OPUC Order No. 17-386, Oct. 9, 2017, pg. 14

 Staff will need a better understanding of the drivers to PGE's capacity need and how PGE plans to identify and pursue bilateral contracts before being able to provide any feedback on potential Staff support for this item.

Per the 19-1 presentation, PGE's projected 2021 capacity needs range between 0 MW to nearly 500 MW.<sup>5</sup> Yet in last year's IRP update, PGE's 2021 capacity need stood at 112 MW, and would drop to 73 MW if PGE's most recent renewables request for proposal (RFP) was completed.<sup>6</sup> Staff is very unclear as to the drivers behind PGE's very near-term capacity need and what appears to be the equal weighting of the high, reference, and low capacity "need case" utilized in the IRP Action Plan. Staff was somewhat surprised at the amount of 2021 capacity need in PGE's reference case given the combined addition of new renewables via the RFP, the continuing resource additions via qualified facilities (QFs), and the higher levels for energy efficiency and demand response than had been forecasted in the previous IRP.

Staff does appreciate that PGE included forecasts of future capacity need based on contracts not expiring. Staff would need a better understanding if these "non-expiration" scenarios also include QF's.

Finally, the addition 322 aMW of capacity via bilateral contracts in the past IRP cycle required a tremendous amount of effort by PGE staff, the OPUC bringing market insights on possible hydro capacity availability to bear, and, overall, a fair amount of coordination amongst all stakeholders. Staff would need to better understand the strategy and tangible steps behind the Action Plan's proposed "staged procurement."

### Section 2, General Feedback on the 2019 IRP

The comments below represent general ideas, concerns, or comments by Staff on the IRP analysis that did not neatly "fit" with the comments on the Draft Action Plan as presented in February 2019. Staff views these comments as a "jumping off" point for deeper discussion either prior to the IRP being released or afterward. We look forward to working with PGE and stakeholders to better explore and prioritize addressing these comments as part of the 2019 IRP process.

### PGE's Preferred Portfolio(s)

- How the draft action plan reflects the preferred portfolio is not clear.
- It is unclear how the benefits of storage are captured (...or not.)
- While Staff appreciates the tension around the exact resource needed to meet a future capacity need, much like the last IRP Staff is concerned that PGE cannot be more specific around resource type and hopes any final action plan will be more specific.
- Staff appreciates some steps PGE appears to have taken to include/review shorter duration resources in the IRP, however we need more information behind the assumptions and analysis (sensitivities) regarding these resources in the IRP resource portfolio. This is especially important as PGE's "reference case" shows nearly 700 MW of capacity need in 2025 with 280 MW based on contracts "rolling off."
- Staff is happy to hear that PGE is open to adding a few additional portfolios. We appreciate PGE's flexibility on this.

<sup>&</sup>lt;sup>5</sup> See PGE 2019 Integrated Resource Plan, Roundtable19-1, February 27, 2019, pg. 16. Further, PGE's RFP was successfully completed. PGE will secure upwards of 150 MW of new capacity, potentially 50% higher than the 100 aMW acknowledged in PGE's revised renewable Action Item from Order 18-044. <sup>6</sup> See PGE's March 27, 2018 Compliance Filing with Order 18-044 in LC 66, pages 2-3.
- Staff will need to better understand the Company's proposed sufficiency/deficiency periods, which we believe (according to proposed Action Plan) are 2030 for renewables and 2025 for generic capacity. Staff will also be interested in how results in PGE's IRP – especially around renewable deficiency date, production tax credits, and resource costs – will impact PGE's avoided cost filings that will emerge following a Commission acknowledgement.
- Staff has concerns about the non-traditional screens, especially the near-term cost criteria, as it would appear to unduly favor near-term purchases limiting optionality and unnecessarily locking in resource pathways during a time of change.

### Coal Retirement Evaluation

- Staff requests an evaluation of the cost and risk of portfolios that assume alternate pre-2035 exit dates from Colstrip as compared to PGE's currently expected exit date.
- Staff requests a comparison of the preferred portfolio with a portfolio that has the same assumptions as the preferred portfolio, except uses the Company's estimate of a cost-and-risk-optimal pre-2035 exit from Colstrip.

### Transmission

- Staff believes that despite the work PGE did around modeling Montana Wind, the IRP's general inability to consider transmission as a resource is problematic, especially in light of the proposed acquisitions. PGE's position that their current IRP cannot solve for transmission and will not consider it until the next IRP gives Staff pause around the uncertainty of further near-term resource acquisitions.
- How does limited availability of transmission, as reflected in PGE's most recent RFP impact the Company's preferred portfolio development in this IRP?

### Planning Horizon, Acquisition Constraints, and Related Assumptions

- Staff has concerns about the IRP's 2050 horizon when combined with PGE's proposed annual constraints on MW acquisitions. In effect the combination overweighs near-term acquisitions to solve for relatively uncertain out-year "needs" and creates a path dependency that limits optionality. Staff would like to work with PGE to better understand the combination of these two factors and to develop scenarios/sensitivities which adjust them to see how they impact preferred portfolios.
- Staff is uncertain if PGE's proposed two-year renewable procurement cycle unduly constrains selection of optimal portfolios.
- Does PGE model any scenarios based on a select emissions trajectory? And if so, how did it impact the resources selection in the preferred portfolio?
- Staff would like to better understand gas prices in 2040.
- To what extent does the capacity factor of wind and solar reflect actual performance of PGE resources or resources under contract to PGE? Please explain.
- Staff will need to better understand the interplay of economic dispatch and PGE's future energy need as it would appear to limit production at the level of outside market prices which are not necessarily accessible by PGE.
- Staff is concerned about non-intuitive results seen in the modeling, especially as related to batteries and diversity. To this end, Staff remains very interested in how large-scale, pumped hydro storage is modelled and selected as it would appear to be a low-emission flexible capacity option to help with the integration of renewables.
- Staff is not clear of the reasoning underlying PGE's comfort level of being up to 250 MWa long on resources.
- PGE has introduced additional non-traditional metrics to screen portfolios Staff will need more explanation around this approach.

• Staff would like more understanding around inclusion of resources in the preferred portfolio that may not be available, such as pumped storage.

#### Competitive Bidding Guidelines

• It is Staff's understanding that PGE is proposing a parallel RFP process to accompany its IRP process. Staff would like PGE to explain how all proposed resource acquisition in this IRP comports with the Commission's new competitive bidding guidelines.

March 29, 2019

Organization: None

IRP Topic(s) and/or agenda item(s): Carbon free generation

Comment:

I am happy to read that PGE is no longer considering new natural gas power plants to replace your coal plant at Boardman. You are going to get by on more purchased hydro, wind, solar, and storage? If you haven't already, please check into Ambri and their liquid metal batteries. They might be the storage solution you need.

We live on the Pacific Ring of Fire; it is nutz that we don't use high-temperature geothermal in the PNW. Boardman is 135 air miles from the middle of PDX' main runway. Mt. St. Helens and Mt. Hood are both 46 miles away. How much would that reduce line losses? Yes, geothermal is expensive up front, especially if you do it right; but you don't have to buy a train load of coal, or equivalent gas, every day, so over time it is supposed to be competitive. Iceland pipes steam miles to geothermal plants with no appreciable heat loss. I see clearcut, on Google earth, within five miles of St. Helen's south rim, roads less than three miles away. I'm sure you could find an unobtrusive place to site a no-emissions geothermal plant where it wouldn't offend too many people.

But there might be a better, less expensive, way to power the foreseeable future. Are the turbines and generators etc. at Boardman still serviceable, or refurbishable? More than one start-up in the U.S. is ready to build a molten salt fission reactor; you could demolish the coal boilers at Boardman, replace them with reactors, and continue using the rest of your expensive equipment, some of which you upgraded not that long ago. The temperatures should be about right—MSRs run at around 700°C? Can you dilute that down to 540, if you need to?—to just drop-in the right size reactor.

Five years ago—maybe even two yag—I'd have given you resistance over the suggestion of building a new fission power plant anywhere in the PNW. I still would, should you consider any kind of pressurized water reactor. But I've done a lot of research since then. MSRs should be much safer: the ORNL model, at least, is designed so that a "melt-down" positively stops the reaction and renders the reactor safe; they operate at atmospheric pressure, so they are not steam explosions waiting to happen; they can continuously reprocess fuel, so far less dangerous material leaves and returns to the site, subject to accidental spill or terrorist theft; they can burn ~96% of their fuel, instead of the 4% a solid-fueled PWR burns before its fuel rods need reprocessing that we don't do, for fear of proliferation; and the best part is that they can burn up the 96% of the expensive fuel left in those PWR solid-fuel rods. This is how we solve our high-level radioactive waste storage problem. We have fuel for thousands of years already mined and in storage; no need/excuse for uranium miners to dig up Grand-Staircase Escalante and Bears Ears or any other national monuments. And all the fuel you would ever need is right up the river at Hanford.

I realize that selling nuclear power in the PNW would be an uphill battle. It would require public education; but I think that if you explain molten salt fission as I did above, most people will understand. I was a Greenpeace volunteer 35 yag, and I've been a staunch no-nuker ever since. If you can sell molten salt fission to me you can sell it to anyone who thinks. I'm a technical writer; let me know if I can help

### **Attachment A: 2019 IRP Stakeholder Comment Record**

with that. Meanwhile Bill Gates' TerraPower would love to build someone one of their reactors; I read that the DOE is urging them to build one in the U.S., while the NRC is in the way. Maybe our excellent congressional delegation could help with that? Perhaps we could get DOE to indemnify you, and reduce the risk?

I would not recommend a TerraPower Travelling Wave Reactor, or any other cooled with liquid sodium, which explodes into flame on contact with air, and burns even more violently in water. Starting with an inherently unsafe design and trying to make it safe with technical fixes is (one of) the problems(s) with PWRs. But TerraPower's Molten Chloride Fast Reactor sounds as safe as any fluoride salt reactor.

Or ThorCon would build you a copy of ORNL's MSR, in big modules they would ship/barge through Panama and up the Columbia to Boardman. Then you would need an Aeroscraft or Lockheed-Martin big lifter—250 or 500 tons—to fly the modules to the plant for you. Great way to showcase both "new" technologies. Set up a motorized tie-down system on rails for the dirigible so that you can inch it side to side and back and forth, and it could lower the components exactly into place—no crane needed.

And find/create an industry there, to make efficient use of your waste heat, please?

Were the turbines, generators etc. at Trojan demolished, or mothballed? They'd be designed for lower temperatures; I wonder if you could make them work with a MSR? I hope MSRs will prove so inexpensive that you will replace your gas turbines with them, too. Please try one and see.

A coal plant at Centralia is shutting down next year, too? If you like this idea, please talk to them.

Separate issue: do you folks have megatons of fly ash stored somewhere? You know that we have a lot of crumbling infrastructure that needs repairing. I hope you know that it is crumbling because it was built with Portland cement (OPC) and steel reinforcement, which are not compatible in the long term; like PWRs, that late-19th-Century experiment has proven itself a bad idea. If we rebuild with the same wrong materials, our grandkids will have to do it again in 60 years. And however many gigatons of OPC that would take, making it would put almost that much CO2 into the atmosphere. Very bad idea.

Fly ash cements need add no more CO2 to the atmosphere (the coal is already burned) and especially if made with magnesium oxides, I understand they can draw ~0.4 ton of CO2 out of the atmosphere for every ton of cement laid down? There may be ways to bind CO2 into the fly ash first, or mix with carbonated water, and sequester even more carbon. We have gigatons of coal ash stored around the country, where it contaminates groundwater with heavy metals in at least 22 states. Making it into cement is supposed to either neutralize or sequester those contaminantes. We safely dispose of toxic wastes, avoid a ridiculous amount of CO2, and sequester more carbon, with stronger cements that should last much longer than OPC. AND it should cost less. That's a whole bunch of "wins" in a row.

PNNL has a new process that requires <300°C. to "calcinate" magnesium oxide from seawater, instead of >900°. You need an alkaline activator—calcium hydroxide from sea water? You already have the bulk of the cement components in your fly ash ponds/piles. Why not go into the cement business—and the sequestering carbon business and the helping save civilization business—and safely and ethically dispose of your toxic waste problem--all at the same time?

April 3, 2019

Organization: None

IRP Topic(s) and/or agenda item(s): Battery storage

Comment:

Reading further in your strategic plan I see that you intend to rely on lithium-ion batteries for grid-level storage because they're a known quantity and so less risky. That reminds me of the folks building ITER: advances since the design went down on paper made it obsolete years ago, and it is probably--realistically--still 30 years away from proving that Tokamaks are a lousy way to generate electricity. But they are "building the plan" while wearing blinders, and we the world's taxpayers will be stuck holding that \$50 billion bag when LPP or Helion Energy or another of the younger smarter more daring start-ups exploring aneutronic fusion bring it on line in five or seven or ten years.

An MIT spinoff called SolidEnergy is in production of lithium metal batteries that solve the old shortingout problem that made LM dangerous, store more amp-hours in 1/2 the size and weight of Li-ion, and can be made on existing Li-ion manufacturing equipment. They use far less lithium—a strategic material rare throughout the universe, not just on Earth—and they should be less expensive.

MIT spinoff Ambri has been developing liquid metal batteries for several years, and they've gone through a number of different chemistries, all of which, I read, worked well, seeking the longest-lasting, most energy dense, and least expensive grid-level batteries. If you haven't, please see MIT prof Donald Sadoway's TED Talk, "The missing link to renewable energy." Please note where he says that their design paradigm is to seek out the least expensive materials and methods: "if you want something dirt cheap, make it out of dirt." One of their latest designs uses molten sodium, which is incredibly luminous, and a form of photovoltaics. They are doing amazing work, some of it is already in production, and I would not plan a utility-level energy storage project before having a long talk with Donald Sadoway.

Suggestion? Distribute your battery modules to substations, or neighborhoods, close to where the energy will be consumed, so that damage to the grid creates outages for the fewest customers. If you keep the modules small—shipping containers full of batteries?—I think Ambri does that--you can afford to try different technologies before deciding on the most cost effective. You can add capacity a little at a time, as you need it, and your customers won't get stuck paying for an expensive long-term large-scale project when—if—when!--Lawrenceville Plasma Physics gives us 5MW, boron11-proton, dense plasma focus fusion reactors with direct energy conversion for \$0.5 million each and ½ cent per kwh. I'd still like to see you replace the boilers at Boardman with molten salt fission reactors; burning up high-level radioactive wastes is its own reward, and given our problems with storing/disposing of it, I'll bet you could get some sort of remuneration from DOE for burning some up.

Finally this: I appreciate you trying to keep my rates as low as possible. But it is more important to leave your grandchildren and mine a livable future. Please be smart about it, but please choose the lowest-carbon alternatives available, even if they cost me a bit more.

#### April 12, 2019

Organization: OPUC

IRP Topic(s) and/or agenda item(s): Draft action plan. Item #3, sub-topic A

#### Comment:

In light of several things - including proposed Action Item 3.A., the bilateral negations in LC 66 and today's announcement by Microsoft and Chelan PUD - the Oregon PUC is very interested in the IRP addressing "how" PGE will communicate with stakeholders the activities undertaken to pursue cost competitive, existing capacity in the region via bilateral negotiations as detailed in Draft Action Item #3.A.

#### May 2, 2019

Organization: Renewable Northwest

IRP Topic(s) and/or agenda item(s): Comments on transmission and the 2019 IRP, future RFPs and future IRPs

#### Comment:

Renewable Northwest is grateful to PGE for its receptiveness to stakeholder feedback throughout the 2019 IRP process. In these comments, we reiterate our concern that PGE could miss an important opportunity to explore a different treatment of transmission in the 2019 IRP that could lead to least cost and least risk solutions that also maintain resource adequacy. We also encourage PGE to begin exploring RFP design issues related to transmission. Finally, we encourage PGE to commit to a thorough exploration of the changed regional transmission landscape in its next IRP.

#### 2019 IRP

As we expressed in our comments of February 11, 2019, we are concerned with PGE's planning assumptions (whether implicit or explicit) that: a) sufficient transmission is available to deliver resources to the utility's system; and, b) long-term firm ("LTF") transmission rights are available on neighboring systems. Neither of these assumptions appear to be reasonable. Our concern is based on the scarcity of LTF rights to deliver to PGE over BPA's system. Recognizing this transmission landscape in the resource planning context is important as PGE prepares to meet resource needs identified in its 2019 IRP.

We therefore reiterate our request that PGE model sensitivities in the 2019 IRP in which the utility assumes that future resources may deliver to its system over "conditional-firm" ("CF") transmission or similar transmission products. Using historical CF curtailment data (from BPA or other transmission providers) to model resources will enable PGE to explore the impact of reliance on such transmission products on its system, and potentially identify new least cost, least risk solutions that also maintain resource adequacy.

#### Upcoming RFP

Renewable Northwest recommends that PGE considers the potential use of CF transmission (or similar transmission products) during any subsequent RFP design phase. We also encourage PGE to determine how it could model and rank bids relying on different transmission products. Given that these are complicated issues, we encourage PGE to begin exploring them as soon as possible. Early action on use

### Attachment A: 2019 IRP Stakeholder Comment Record

of non-LTF products in its RFP design is especially important if the 2019 IRP only assumes that new resources would rely on LTF transmission.

Renewable Northwest also recommends that the transmission requirements of any RFP pursuant to the 2019 IRP are designed with BPA's 2019 and 2020 TSR Study and Expansion Process (TSEP) timelines in mind.

BPA announced today the completion of the Cluster Study phase of the 2019 TSEP proces. BPA will work through the financial analysis, results, and any next-step funding agreements between now and the end of July 2019. As a result, participants in the 2019 TSEP should have information from BPA about when they can expect to be granted transmission access, and what any upfront costs may be, by the end of July. At that point, those customers could decide to move forward or exit this year's TSEP and wait for the 2020 TSEP.

An announcement on the 2020 TSEP is planned around the end of June 2019, with the queue restack resulting from the 2020 TSEP being announced at the end of the year. At that point, certain customers could be awarded transmission without any upgrades. For the rest of the customers, the transmission study work and financial analysis and next step funding agreements would follow a similar timeline to the 2019 TSEP, to be completed around August of 2020.

As PGE begins preparing its next RFP, we encourage the Company to design transmission-related requirements that would allow for participation of resources going through the 2019 and 2020 TSEP process.

#### Future IRPs

Renewable Northwest also encourages the Company to commit to thoroughly examining how the IRP must adapt its transmission assumptions given regional transmission constraints and the scarcity of LTF rights over neighboring systems.

As part of that process, we suggest that PGE models sensitivities that assume the use of CF or similar transmission products and make use of historical curtailment data. Specifically, PGE could run sensitivities on a set of curtailment assumptions (i.e. 1%–5% of the hours in a year). PGE should use the historical curtailment shape of BPA's CF product (month/day/hour of the year) and work with stakeholders to shape the timing and system impacts of these curtailment sensitivities.

Renewable Northwest also suggests that PGE identifies in future IRPs its existing transmission rights on BPA's system and that it considers how those rights could be used to support a portfolio of resources that may meet needs that the Company identifies in the IRP. For example, PGE could consider a new resource that brings its own transmission rights to Mid-C, but that relies on PGE's existing transmission rights from Mid-C to its system. In this scenario, PGE would be using their Mid-C-to-PGE transmission leg to facilitate delivery of power from either the Mid-C market hub or a new resource, depending on the circumstances for a particular hour. Such an approach could use that transmission asset more efficiently by supporting multiple resources; however, it could also have an impact on the total deliverability and resource adequacy contribution from one or more of the resources using that same transmission leg. We encourage the Company to explore this issue as the tradeoffs between cost-effective use of transmission and the value of delivered resources can only be modeled as part of the IRP process. PGE should also consider options for redirecting existing firm transmission to new resources, on a long-term or short-term basis, that may provide greater benefits to PGE's customers, for all or certain parts of year.

#### May 7, 2019

Organization: Renewable Northwest

IRP Topic(s) and/or agenda item(s): Comments of PGE's draft solar integration costs

Comment:

Renewable Northwest and the NW Energy Coalition thank PGE for its receptiveness to stakeholder feedback throughout the 2019 IRP process. In these comments, we again outline our concerns with PGE's draft solar integration cost and suggest a different modeling approach that we expect could allow the Company to more accurately capture the variability of solar resources and therefore could lead to more accurate integration cost. We close by requesting that the Company discusses with stakeholders the topic of solar integration in greater detail.

We are concerned with the high draft solar integration number that PGE presented on 2/27/2019. PGE presented a draft solar integration cost for its 2019 IRP of  $\$_{2025}$ 1.51/MWh, a figure significantly higher than the  $\$_{2016}$ 0.83/MWh in PGE's 2016 IRP. This draft solar integration cost is inconsistent with what we would expect to see compared to other renewable energy resources when taking into account the expected "diversity effect" of adding solar or Montana wind to PGE's existing fleet of predominantly Gorge wind. Lower integration costs for Montana wind than for additional PNW wind are expected. While we would also expect a similar diversity effect for adding solar to PGE's resource mix, PGE's 2019 IRP draft solar integration costs are moving in the opposite direction. This is counter to the diversity effect we would expect to see.

Renewable Northwest outlined several of the concerns included in these comments at a February 1, 2019 meeting with PGE IRP Staff. In that conversation, we explored in some detail how PGE uses ROM to calculate solar integration costs and how PGE forecasts the generation profile of the future solar projects the Company is likely to integrate. Specifically, we expressed concern about what we understand to be PGE's use of linear scaling based off a single solar resource data point because such an approach likely produces results that systematically exaggerate the variability of larger single solar plants and of a more diverse buildout of the solar resources that PGE is likely to integrate.<sup>[1]</sup>

Renewable Northwest and the NW Energy Coalition want to again strongly encourage PGE to change its approach to modeling future solar plant variability so that it can accurately account for diversity across plants and even within larger plants. Specifically, we recommend that PGE collects a broader data set for use in estimating the 2019 IRP solar integration costs. For example, PGE could rely on the University of Oregon solar insolation data set as it provides a geographically diverse collection of raw solar insolation data points around the Northwest.<sup>[2]</sup>Other entities in the region have relied on that data. Specifically, the Bonneville Power Administration used this data set to assemble its own solar generation data set that is representative of its large and geographically diverse interconnection queue.<sup>[3]</sup>

Finally, we respectfully request that PGE explores in detail its methodology to calculate integration costs for renewable energy resources as well as the driver(s) for this drastic increase in solar integration cost at a large group IRP meeting or at a technical workshop. We also request that PGE present the disaggregated average showing the hour, day-ahead, and within-period stages separately so that PGE and stakeholders can more accurately explore the root cause of this drastic modeled cost increase.

### Attachment A: 2019 IRP Stakeholder Comment Record

June 7, 2019

Organization: National Grid and Rye Development

IRP Topic(s) and/or agenda item(s): Comments on roundtable 19-2 and the 2019 draft IRP

Comment:

Attached please find the comments and supporting materials submitted on behalf of National Grid and Rye Development. These comments address both PGE's Presentation at the May 22nd 19-2 Roundtable IRP Meeting and the 2019 Draft IRP.

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June 7, 2019

Elaine Hart Manager – Integrated Resource Planning Portland General Electric 121 SW Salmon St. Portland, OR 97204

RE: Roundtable 19-2, May 22, 2019 and 2019 Draft IRP

Ms. Hart and PGE IRP Staff -

National Grid USA ("National Grid") and Rye Development, LLC ("Rye") appreciate the opportunity to present these comments on Portland General Electric's ("PGE") May 22, 2019 presentation at Roundtable 19-2 (the "Presentation") and PGE's 2019 Draft IRP (the "Draft IRP").

### I. Overview

National Grid and Rye continue to have concerns about two issues discussed as part of PGE's Presentation and presented in the Draft IRP. First and foremost, National Grid and Rye have significant concerns about PGE's plan to conduct a staged procurement process to secure the necessary capacity that PGE needs to meet its resource adequacy requirements. In particular, slide 42 of the Presentation and section 8.4 of the Draft IRP note that PGE still expects to pursue a staged procurement process, with pursuit of cost competitive existing capacity via bilateral negotiations occurring first.<sup>1</sup> Only after that stage is complete does PGE expect to issue a "Non-Emitting Capacity RFP" in 2021 for any remaining capacity needs.

National Grid and Rye request that, instead, PGE conduct a single, "all-encompassing" RFP to acquire capacity from both existing and new capacity resources to meet its future needs. This all-encompassing RFP would be conducted shortly after the Oregon Public Utility Commission ("OPUC") acknowledges PGE's 2019 Integrated Resource Plan ("IRP") and its associated Action Plan, in lieu of pursuing bilateral negotiations first and then later conducting a Non-Emitting Capacity RFP. As further explained below, this all-encompassing RFP could seek capacity from both new and existing capacity resources, while also constraining the types of resources to those that are non-emitting or that meet other criteria specified by PGE and acknowledged by OPUC as part of PGE's IRP process.

Alternatively, if PGE is unwilling to pursue this more holistic, "portfolio"-based approach, then PGE should, <u>at minimum</u>, conduct the Non-Emitting Capacity RFP <u>simultaneously and in</u>

<sup>1</sup> 

Presentation at 42; Draft IRP at § 8.4, pp. 199-200.



<u>parallel</u> with its effort to bilaterally acquire capacity from the market in 2020. Additionally, as shown in the included white paper from Navigant Consulting,<sup>2</sup> there is an increasing future need for longer-duration storage as more renewable resources are added to the electrical grid, which is likely to occur simultaneously with the retirement of large capacity resources like coal plants in the near-term horizon. Therefore, prudent planning suggests that PGE should consider both near- and long-term contracts, as well as capacity from both existing and new capacity resources, in order to best insulate PGE from potential market risk factors.

Second, National Grid and Rye continue to believe that PGE is not accurately evaluating long duration (greater than 4 hours storage) lithium-ion battery systems, which results in an unfair comparison with other storage resources. For example, the table on slide 22 of the Presentation (Table 7-4 in the Draft IRP) suggests the costs of a portfolio with a 6-hour battery system are similar to one with a pumped storage resource.<sup>3</sup> However, as National Grid and Rye explain below, if PGE were making an "apples-to-apples" comparison of these resources, those two resources should not be close in terms of costs. Furthermore, National Grid and Rye believe PGE's analysis of lithium-ion battery systems, such as the fire and explosion that recently occurred at one of Arizona Public Service's ("APS") battery storage facilities.<sup>4</sup> In contrast, pumped storage system do not pose these same safety risks and have a proven track record of reliable, safe operation throughout the United States and internationally.

### II. Comments on PGE's Capacity RFP

As alluded to above, National Grid and Rye request that PGE consider taking an alternative approach to acquiring capacity to meet its future resource adequacy requirements. That is, as further explained in Section II.B below, National Grid and Rye believe conducting a single, all-encompassing RFP to acquire capacity for varying durations and from both existing and new capacity resources is a better, and more prudent, approach.

Alternatively, if PGE is unwilling to pursue an all-encompassing RFP to acquire any needed capacity, then PGE should, at minimum, modify its approach to meeting its resource adequacy needs by aligning its Non-Emitting Capacity RFP—currently anticipated to occur in 2021—with its strategy of pursuing cost competitive existing capacity via bilateral negotiations (expected to occur in 2020).<sup>5</sup> When considering advancing the Non-Emitting Capacity RFP, National Grid and Rye also recommend that PGE take more of a "portfolio" approach to acquiring the capacity needed to meet its future resource adequacy obligations by considering both multiple types of

<sup>&</sup>lt;sup>2</sup> Anna Giovinetto and Alex Eller, *What is Driving Demand for Long Duration Energy Storage?* at Section 3.2, Navigant Consulting, Inc., Q2 2019.

<sup>&</sup>lt;sup>3</sup> Presentation at 22; Draft IRP at § 7.2.2, p. 173.

<sup>&</sup>lt;sup>4</sup> HJ Mai, Not All Batteries are Made Equal – APS Battery Fire Highlights Safety Risks, Lack of Knowledge, Utility Dive, June 5, 2019, available at: <u>https://www.utilitydive.com/news/not-all-batteries-are-made-equal-aps-battery-fire-highlights-safety-ris/555185/</u>.

<sup>&</sup>lt;sup>5</sup> Comments of National Grid USA and Rye Development, LLC at 4-5, filed March 22, 2019 ("March 22 Comments").



technologies as well as differing durations of contracts. Taking such a holistic approach would ensure a diverse set of resources that would reduce PGE's exposure to market risks while also providing a more robust and reliable generation fleet.

Pursuing one of these alternative approaches to acquiring capacity—either an all-encompassing RFP or moving up its Non-Emitting Capacity RFP to 2020—would also provide PGE with a more complete set of potential capacity resources, which would ensure PGE is meeting its resource adequacy requirements with the least cost and most reliable long-term resources. This is particularly important, given the impending near-term capacity shortfall in the region where utilities across the area are expected to be significantly short on capacity. This shortfall is further compounded by Washington State passing its 100% clean energy bill, which requires complete phase-out of coal generation by 2025 and, as has already been seen in the region, that new natural gas projects are difficult (if not impossible) to permit and build (e.g., Carty 2).

### A. <u>Pursuing Bilateral Capacity Additions First Provides Existing Resources an</u> <u>Unfair Advantage</u>

National Grid and Rye are concerned that conducting bilateral negotiations first, before issuing the Non-Emitting Capacity RFP in 2021, would effectively give existing resources priority to meet PGE's future capacity needs, to the detriment of new capacity resources. This approach would also deprive PGE of important information that a more holistic, "portfolio"-based approach would provide. For example, a "portfolio" approach would consider all potential sources of capacity when comparing costs and benefits to determine the best set of resources to cost-effectively and reliably meet PGE's future capacity needs. Additionally, a "portfolio" approach would likely: (1) provide PGE's system with potential efficiencies associated with capacity portfolio diversity, (2) insulate PGE from capacity and fuel price fluctuations through longer-term contracts and a diversity of resource types, and (3) increase PGE's operational flexibility due to the optionality associated with shorter-term market contracts and longer-term contracts from newly-constructed capacity resources.

A truly unbiased approach would be indifferent to whether PGE's future capacity needs are met by an existing or new capacity resource. However, PGE's current phased approach would give existing capacity resources the "first bite" of the capacity apple, thereby reducing PGE's future capacity need and, in doing so, reduce the amount of capacity that might be supplied by new capacity resources. This approach unfairly favors the status quo and existing resources, in addition to unnecessarily exposing PGE to future capacity market risks, as laid out below.

Furthermore, the currently-proposed approach is akin to piecemeal planning and effectively circumvents the entire purpose of the long-term planning process. By focusing primarily on short-term contracts to first meet its capacity needs, large capacity resources like a pumped storage project are not given an opportunity to compete for utilities' capacity needs and, thereby, developers of large capacity resources are unable to finance and build new capacity, resulting in no new capacity being constructed in the near-term. As a result, focusing first and foremost on short-term contracts from existing resources, as PGE is currently proposing, undermines the purposes of the long-term planning process and is likely to create an even greater capacity



shortfall in later years. This will become increasingly problematic as capacity from existing resources becomes more and more constrained in the near- to medium-term, as further explained below.

In order for both existing and new capacity resources to compete on level ground, National Grid and Rye strongly urge PGE to consider issuing a single, comprehensive RFP for all capacity it needs to meet its future resource adequacy requirements. This "all-encompassing" RFP concept is further laid out in the following section. However, if PGE refuses to consider this allencompassing RFP approach, National Grid and Rye request that PGE move up its Non-Emitting Capacity RFP to 2020 and evaluate any responses it receives from new capacity resources against the offers PGE receives via bilateral negotiations. Conducting bilateral negotiations and the Non-Emitting Capacity RFP simultaneously would be more prudent than PGE's currentlyproposed, phased approach, and would better determine the least-cost and most reliable set of capacity resources to meet PGE's resource adequacy requirements now and into the future.

#### B. <u>Rather than Pursuing a Staged Approach, PGE Should Consider Conducting a</u> <u>Single, All-Encompassing RFP to Meet its Future Capacity Needs</u>

As noted above, while National Grid and Rye would like, <u>at minimum</u>, to see PGE move up the Non-Emitting Capacity RFP to occur simultaneously with its efforts to bilaterally acquire capacity from existing capacity resources, <u>an even better approach</u> would be for PGE to conduct a single, all-encompassing RFP to acquire all of the capacity it needs to meet its future resource adequacy requirements. Like PGE's current plan for bilateral negotiations, this RFP could be issued shortly after the OPUC acknowledges PGE's IRP and the associated Action Plan, which is currently anticipated to occur around the end of January 2020.

Conducting a single, all-encompassing RFP to meet all of its future capacity needs provides several significant benefits over PGE's currently-proposed, phased approach. For example, a single RFP approach would ensure PGE has as much information as possible to evaluate the capacity market as a whole and ensure it is making the best-informed decisions about which set of resources will most cost-effectively meet its future capacity needs. Similarly, the single RFP approach is truly indifferent to resource type and allows both existing and new capacity resources to compete to meet PGE's capacity needs on level footing. This revised approach would also allow PGE to obtain a more holistic view of both the existing and future capacity market, which would be beneficial in the event that any of PGE's current assumptions about available capacity become inaccurate with time.

Additionally, this modified approach would come with added flexibility for PGE, given the broader range of resources PGE would be considering to cost-effectively and reliably meet its future capacity needs. This added flexibility also reduces PGE's exposure to some of the market factors laid out below, thereby making such an approach a more sound and prudent planning approach. Another flexibility benefit this approach would provide is that it would allow PGE to better shape the timing of its contracts with existing capacity resources to align with the online dates for new capacity resources. For example, depending on the bids received from new resources (assuming they were cost competitive), which are likely to vary depending on each

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resource's anticipated commercial operation date, PGE could alter its bilateral contracting approach to acquire capacity from existing capacity resources by seeking longer or shorter contract terms, or perhaps consider options to extend contracts with existing resources to fill any near-term needs while new resources are being constructed.

In terms of logistics of this all-encompassing RFP, National Grid and Rye recommend that PGE begin preparing the RFP for issuance at the end of 2019, such that it could be issued shortly after the OPUC acknowledges PGE's IRP in early-2020. The all-encompassing RFP could include any parameters PGE might consider appropriate, as long as those conditions were also acknowledged as part of the IRP process. Such parameters might include things like the capacity must be: (1) non-emitting; (2) capable of providing at least a pre-defined amount of capacity to PGE (e.g., 25 MW or more); and (3) willing to commit to a minimum, pre-defined contract length (e.g., at least 5 years). There are numerous other parameters PGE might deem appropriate in order to comply with its future resource adequacy requirements, likely future legislative mandates, renewable portfolio standards, system conditions, and the like. In any event, these parameters could all be fleshed out during the IRP process before the OPUC and included in PGE's Final IRP filing for acknowledgement by the OPUC.

National Grid and Rye believe this all-encompassing approach is a better approach for acquiring capacity to meet PGE's future capacity needs because it is truly non-discriminatory, insulates PGE from market risks, advances the timing for acquiring capacity from new resources, and provides PGE with the best chance of actually realizing its carbon reduction goals through the resources included in the Draft IRP's "Mixed-Clean Portfolio."

C. <u>Without Advancing the Non-Emitting Capacity RFP to Coincide with Bilateral</u> <u>Capacity Negotiations, PGE's Draft IRP Assumes Capacity Exists that May Not</u> <u>Actually be Available</u>

PGE's Draft Action Plan suggests that it intends to pursue a "staged procurement process" that would focus on securing "cost competitive existing capacity in the region via bilateral negotiations" before conducting a Non-Emitting Capacity RFP in 2021 to fulfill any capacity needs that remain.<sup>6</sup> As National Grid and Rye understand it, under this approach, PGE would begin bilateral negotiations shortly after the OPUC acknowledges PGE's IRP and the associated Action Plan, likely in early 2020.

PGE's Presentation and Draft IRP indicates that its preferred portfolio—referred to as the "Mixed Full Clean Portfolio"—includes approximately 200 MW of capacity from a pumped storage resource beginning in 2024. However, the assumption that pumped storage will be available in 2024 is faulty if PGE does not, at minimum, move up its Non-Emitting Capacity RFP to 2020. While National Grid and Rye continue to support PGE in its efforts to model and include pumped storage as a viable energy and capacity resource in its Draft IRP, the assumption that such a resource will be available in 2024 rests on the premise that a definitive agreement to purchase (at least) a share of the capacity from such a resource could be reached by the end of

<sup>&</sup>lt;sup>6</sup> Presentation at 42.

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2020, which is necessary to match up the procurement process with the longer-lead time required for construction of pumped storage projects. Entering into an agreement by this date would allow enough time for a party like National Grid and Rye to procure, engineer, finance, and construct such a significant resource, while meeting the 2024 commercial operation date needed to satisfy PGE's upcoming capacity needs.

National Grid and Rye believe <u>very few</u> pumped storage resources located in the Pacific Northwest are far enough along in the development process to have a chance at meeting the 2024 commercial operation date. Swan Lake is one such resource. As can be seen in the included, high-level schedule, to achieve a <u>mid-2025 commercial operation date</u>, a definitive power purchase agreement or ownership agreement would have to be finalized by the end of 2021. National Grid and Rye believe it would be possible to advance the included schedule by approximately a year—that is, a 2024 commercial operation date—however, doing so would require a definitive power purchase or ownership agreement to be completed by the end of 2020.

Therefore, while National Grid and Rye agree with PGE's modeling results that the Mixed Full Clean Portfolio, which includes pumped storage, is the best mix of resources to meet PGE's future capacity needs, in order to actually achieve the preferred portfolio, PGE must advance its Non-Emitting Capacity RFP to 2020. Doing so would ensure that a developer of a pumped storage project would have enough time to conduct any remaining engineering, secure financing, procure necessary equipment (particularly the turbine-generators, which have up to a five-year lead time), and construct a facility capable of providing the approximately 200 MW PGE believes it will need beginning in 2024. If PGE decides to hold it Non-Emitting Capacity RFP in 2021, as is currently contemplated, National Grid and Rye do not believe there is a pumped storage resource currently under development or in existence that could provide the approximately 200 MW of capacity PGE expects to be available in 2024.

### D. <u>A Staged Approach May Result in PGE Missing Out on Valuable Capacity</u> <u>Opportunities</u>

PGE's current plan to conduct a Non-Emitting Capacity RFP in 2021 may also result in PGE missing out on valuable opportunities to acquire non-emitting, renewable capacity that would effectively and reliably meet its future capacity needs, which is particularly important at a time when increased competition and demand for the capacity from new, carbon-free capacity resources is increasing, thereby potentially driving up rates for customers significantly.

As indicated in the included schedule and explained above, it is imperative for National Grid and Rye's Swan Lake project to achieve a 2024 commercial operation date that a definitive agreement be entered into by the end of 2020. One concept being considered by National Grid and Rye is a "reverse" RFP wherein National Grid and Rye would hold an RFP for buyers of output from the Swan Lake facility, which would be conducted and overseen by Bates and White (see included proposed scope of work). If National Grid and Rye pursue this option, it would occur before PGE's proposed Non-Emitting Capacity RFP in 2021.



If National Grid and Rye elect to run such a "reverse" RFP process, National Grid and Rye envision this process being conducted like a transmission network open season, which could help alleviate the "lumpy" nature of these large projects. In National Grid and Rye's experience, one utility often does not need all of the capacity from a single pumped storage project. For these (and other) reasons, these projects often do not neatly fit within a utility's standard integrated planning process, particularly from a size and timing perspective. In National Grid and Rye's view, the "reverse" RFP process allows utilities in need of future capacity to participate for costcompetitive capacity in an open and transparent process while also allowing utilities to seek to acquire only the amount of capacity needed to satisfy their future requirements.

As a result, if PGE expects National Grid and Rye to bid any portion of its Swan Lake capacity into the Non-Emitting Capacity RFP, then the Non-Emitting Capacity RFP will need to occur sooner. Otherwise, PGE runs the risk of missing an opportunity to acquire any capacity from this facility, as there is always the possibility that National Grid and Rye's "reverse" RFP could result in commitments to purchase all of the capacity from Swan Lake before PGE even issues its Non-Emitting Capacity RFP.

E. <u>Relying Primarily on Bilateral Capacity Market Purchases Exposes PGE to</u> <u>Unnecessary Market Risks</u>

As National Grid and Rye mentioned in their March 22, 2019 comments in response to the materials presented at IRP Roundtable 19-1 ("March 22 Comments") and above, focusing first on bilateral capacity purchases from the market, before conducting the Non-Emitting Capacity RFP, unnecessarily exposes PGE to market risk factors that are likely to dramatically increase over the next decade.<sup>7</sup>

As further explained in this section, several market factors are likely to make it difficult to acquire cost-competitive capacity from existing resources in the Pacific Northwest during the next decade, which coincides with the period during which PGE will be seeking to enter into bilateral contracts for capacity. Instead, PGE should consider taking a more holistic, "portfolio" approach to acquiring the necessary capacity to meet its future needs. Doing so would mitigate PGE's exposure to the market risk factors laid out below by allowing PGE to consider both: (1) differing types of capacity resources, and (2) both short- and longer-duration resources, at the same time market risk factors are being weighed.

One of the first market risks is that the Bonneville Power Administration ("BPA") will be seeking to renegotiate its wholesale power contracts during the same period PGE is seeking to bilaterally acquire capacity from existing capacity resources like BPA's hydropower fleet. As such, it seems likely that capacity purchases from BPA will be for limited durations and become more speculative, particularly as the deadline for renewing its wholesale power contracts approaches. If PGE instead took more of a "portfolio" approach to acquiring its needed capacity, as National Grid and Rye are recommending, longer-term capacity resources and contracts—like those available from Swan Lake and Goldendale—would be available to PGE to mitigate the risk

<sup>&</sup>lt;sup>7</sup> March 22 Comments at 5.



that BPA's contracts are constrained by market factors or commitments for renewed wholesale power contracts.

A second market risk, which National Grid and Rye have seen through their participation in various Pacific Northwest utilities' planning processes, is that almost every utility in the Pacific Northwest is projecting a capacity deficit in the mid-2020's. These capacity deficits became even more pronounced with the recent passage of Washington's 100% clean energy bill. This legislative mandate requires complete phase out of coal by 2025, meaning several other utilities in the Pacific Northwest will be in the market looking for capacity at the same time PGE is seeking to lock in market purchases. Because of this, it is not difficult to project that pricing for capacity from these existing resources may increase, and available supply will likely diminish, due to the increased market demand for capacity. Thus, if PGE continues to insist on conducting a phased approach to acquiring capacity, it could be exposed to skyrocketing prices and tight supply, while also not having the benefit of pricing information from new capacity resources to evaluate whether the market prices it is seeing are competitive with the cost of new resources.

A third market risk is identified by recent studies—such as the one conducted by Energy+Environmental Economics ("E3")<sup>8</sup> on future capacity needs in the Pacific Northwest suggest that the region is going to have a <u>significant</u> capacity deficit within the next decade, if new resources are not contracted for and constructed well before that need arises. For example, E3 suggests that, depending on the timing of coal retirements and the ability to replace those facilities with natural gas facilities, as little as 5 GW, and as much as 16 GW, of net new capacity is needed by 2030.<sup>9</sup> Given Washington's recent passage of a 100% clean energy bill, and the fact that other Pacific Northwest states may follow Washington's lead, it is not unreasonable to assume the higher end of the range provided in E3's study is likely to be closer to our future reality. With that in mind, E3's study suggests that a 100% zero carbon future would require approximately <u>120 GW of new capacity by 2050</u>. Therefore, given the fact that there is likely to be a <u>significant</u> capacity deficit in the coming years, particularly due to recent legislative efforts to reduce carbon emissions and require utilities to eliminate coal and other emitting resources from their resource mix, it would be imprudent for PGE to rely only on existing capacity resources to meet its future capacity needs before considering new resources.

### III. Costs of Lithium-Ion Battery Systems

In addition to the concerns laid out above regarding the timing of PGE's Non-Emitting Capacity RFP, National Grid and Rye would also like to briefly comment on some of PGE's analysis in its Draft IRP for longer duration (greater than 4 hours) lithium-ion battery storage systems. National Grid and Rye believe PGE is not fully capturing the costs of these longer-duration battery systems, which is resulting in an unfair comparison amongst the various long duration storage resources being considered in PGE's Draft IRP, such as between 6-hour batteries and pumped storage. Furthermore, National Grid and Rye believe it is imperative that PGE take into

<sup>&</sup>lt;sup>8</sup> Resource Adequacy in the Pacific Northwest, March 2019, available at: <u>https://www.ethree.com/wp-content/uploads/2019/03/E3\_Resource\_Adequacy\_in\_the\_Pacific-Northwest\_March\_2019.pdf</u>.

<sup>&</sup>lt;sup>9</sup> *Id.* at 38.





consideration some of the additional risks associated with lithium-ion battery storage systems that are not present for pumped storage facilities, such as the explosion and fire that recently occurred at one of APS' battery storage facilities.<sup>10</sup>

#### A. <u>PGE is Not Fully Considering All of the Costs of Long-Duration (Greater than 4</u> <u>Hours Storage) Lithium-Ion Battery Systems</u>

Slide 22 of the Presentation (Table 7-4 of the Draft IRP) suggests that the cost of portfolios that include either a 6-hour battery or pumped storage are nearly equivalent.<sup>11</sup> In National Grid and Rye's experience, that result is virtually impossible, if a true "apples-to-apples" comparison is being made between these two types of storage resources. Therefore, National Grid and Rye believe PGE is not fully considering all of the costs of these longer duration batteries. If PGE did conduct an accurate and complete study of the costs of these two resources, it would be clear that pumped storage is the cheaper resource, while also providing unparalleled benefits that other types of storage resources.

A recent study published by the San Diego County Water Authority ("SDCWA") provides one of the most robust and accurate cost comparisons of pumped storage and long-duration battery storage systems to date.<sup>12</sup> In particular, this SDCWA study conducts a levelized cost of energy comparison between pumped storage and lithium-ion batteries. In doing so, it accounts for the expected useful life of each technology, as well as the replacement cost of a lithium-ion battery system, in order to provide a levelized, true "apples-to-apples" comparison of these two storage technologies.

As shown in the table below from the SDCWA study, there is little comparison between the levelized costs of a pumped storage system and a lithium-ion battery system (even assuming a 40-year useful life for a pumped storage project, which in National Grid and Rye's experience, is extremely conservative).<sup>13</sup>

<sup>13</sup> *Id.* at Figure 7, p. 22.

<sup>&</sup>lt;sup>10</sup> *Supra*, n. 4.

<sup>&</sup>lt;sup>11</sup> Presentation at 22; Draft IRP at § 7.2.2, p. 173.

<sup>&</sup>lt;sup>12</sup> Dr. David G. Victor, *et al*, *Pumped Energy Storage: Vital to California's Renewable Energy Future*, Published May 21, 2019, available at: <u>https://www.sdcwa.org/sites/default/files/White%20Paper%20-</u> %20Pumped%20Energy%20Storage%20V.16.pdf.

# nationalgrid



Figure 7: When evaluating large-scale energy storage options, the two most mature technologies demonstrate favorable options to cost effectively integrate renewable energy on the California grid. With the long, reliable project life of pumped storage, investments today will offer greater savings for future generations. (Sources: combination of Figures 5 and 6).

Furthermore, as noted in the SDCWA study, battery storage systems often require "overbuilding" by 50% or more in order to provide the actual amount of capacity needed to meet a utility's need. This overbuilding is required due to damage battery systems are likely to suffer at full discharge. Specifically, SDCWA notes, "A recent project in Southern California, for example, purchased a 50 MW rated battery system to yield reliably 20 MW of capacity."<sup>14</sup> While SDCWA goes on to note that they did not attempt to capture these real-world differences between rated and useful capacity of battery systems in its levelized cost comparison, if such costs were taken into account, battery storage systems would fare even worse than they do in the figure provided above.

### B. <u>PGE's Incomplete Analysis of Long-Duration Batteries Results in an Unfair</u> <u>Comparison of Costs Between Storage Resources</u>

As alluded to above, because PGE's analysis does not appear to take into consideration the full costs of a 6-hour battery storage system, particularly including costs of battery replacement at least once (and more likely twice) during the useful life of a pumped storage system and the

<sup>&</sup>lt;sup>14</sup> *Id.* at 20.



rated vs. useful capacity of a battery storage system, PGE's comparative screening of these two resources unfairly shows a 6-hour battery storage system as being nearly cost competitive with a pumped storage resource. Based on the excellent study produced by SDCWA noted above, there should be little question that a complete, levelized cost comparison of these two technologies would drastically favor pumped storage. If PGE were appropriately including, for example, replacement costs of these battery systems to produce a useful life comparable to a pumped storage project (at least 40 years), the costs for these resources would likely at least double.

National Grid and Rye suspect that PGE is, at minimum: (1) not comparing the complete costs of long-duration battery storage systems with a pumped storage basis on a true, levelized basis; and (2) ignoring the costs associated with overbuilding battery resources due to the difference between rated and useful capacity of this technology. Including any amount of these costs to produce something closer to a more holistic, "apples-to-apples" comparison between batteries and pumped storage would easily result in pumped storage being the lower-cost resource.

Due to PGE's incomplete consideration of the full costs of long-duration battery storage systems, PGE's current analysis unfairly favors long-duration batteries to the detriment of pumped storage, even though the latter is likely to be the lower-cost, more reliable, and longer useful life resource.

C. <u>PGE Should Also Consider the Safety Risks Associated with Relying on Lithium-</u> <u>Ion Batteries for Needed Capacity</u>

In light of recent events such as APS' explosion and fire at one of its lithium-ion battery storage facilities, National Grid and Rye implore PGE to consider these very real risks of relying too heavily on lithium-ion batteries to meet its future capacity needs. While National Grid and Rye recognize that these risks are difficult to quantify, due to the gravity of such a risk, including potential life-threatening consequences, it is imperative that PGE at least make a concerted effort to take these risks into account in its analysis. Only once these risks are accounted for can PGE make an accurate and reasoned decision on how best to proceed in acquiring additional storage capacity to meet its future needs. Furthermore, while National Grid and Rye recognize that cost is often paramount in the resource planning process, accidents like the one that occurred at APS' battery storage facility demonstrate that least-cost isn't always the safest or most prudent basis upon which to plan an interconnected electrical system, particularly when other, cost-competitive, more reliable, and safer resources like Swan Lake or Goldendale are available to meet that same capacity need.

### IV. Conclusion

National Grid and Rye continue to appreciate PGE's efforts to consider pumped storage as a resource that can verifiably and reliably meet PGE's future capacity needs on a cost-competitive



basis. However, National Grid and Rye continue to have concerns with at least two aspects of PGE's pumped storage analysis.

First and foremost, National Grid and Rye recommend that, instead of its currently proposed, phased approach to acquiring capacity, PGE instead conduct a single, all-encompassing RFP to acquire all of the capacity it needs to meet its future resource adequacy requirements. Such an approach is less discriminatory, provides PGE with greater operational flexibility, and reduces PGE's exposure to the potential market risk factors laid out in these comments. Alternatively, if PGE refuses to conduct a single, all-encompassing RFP, then National Grid and Rye believe PGE needs to, at minimum, move up its Non-Emitting Capacity RFP to 2020. Failure to either move up the Non-Emitting Capacity RFP or conduct a single, all-encompassing RFP would be imprudent and is likely to result in unnecessary exposure to market risks; missed opportunities to acquire capacity from new, non-emitting capacity resources like Swan Lake; and PGE being unable to acquire the amount and types of resources included in its Mixed-Clean Portfolio, largely due to the timing associated with engineering and constructing a pumped storage facility of the size necessary to meet PGE's stated timeline and expected capacity needs.

Second, National Grid and Rye believe PGE's analysis of long-duration battery storage options unfairly portrays this technology as cost competitive with pumped storage because its analysis does not look at the complete costs of these two resources. In particular, PGE's analysis does not appear to fully account for the differing useful lives of a pumped storage and battery system, nor does it consider costs associated with overbuilding battery storage systems to achieve PGE's stated capacity needs. If PGE's analysis did take these costs into account, the battery storage system costs would be significantly higher than those shown in PGE's Draft IRP and, as a result, pumped storage would clearly be the more cost-effective, reliable, and longer useful life resource. Finally, PGE's analysis of long-duration batteries also needs to take into account some of the increased safety risks associated with these storage resources. As APS' recent accident demonstrates, relying solely on batteries can have grave consequences and unnecessarily expose first responders and PGE's employees to potentially life-threatening risks.

Please let us know if you have any questions or concerns about our comments.

Sincerely,

Note Andrig

Nathan Sandvig Director, US Strategic Growth National Grid Ventures <u>Nathan.Sandvig@nationalgrid.com</u>

Erik Steimle V.P. Project Development Rye Development, LLC Erik@ryedevelopment.com

### Attachment A: 2019 IRP Stakeholder Comment Record

June 17, 2019

Organization: Oregon Citizen's Utility Board

IRP Topic(s) and/or agenda item(s): Comments on draft 2019 IRP

Comment: Please find attached CUB's comments on PGE's Draft 2019 IRP.

### **BEFORE THE PUBLIC UTILITY COMMISSION**

### **OF OREGON**

### 2019 PGE IRP

### INFORMAL COMMENTS OF THE

### OREGON CITIZENS' UTILITY BOARD

June 17, 2019



### CUB Comments on LC 73 PGE IRP 2019 Draft

#### A. Load Forecasting Methodology:

CUB would like to comment on the load forecasting assumptions and modeling for Residential and Industrial customers and the base load forecast.

- 1) Load forecasting Assumptions for Residential and Industrial Customers
- a. **Residential load forecast:** The interpretation of the trend term in the Residential Load forecast model<sup>1</sup> is unclear. Why is there a trend term for each month?
- b. Industrial load forecast: PGE forecasts an AAGR of 1.9% in their Industrial load for the period 2020-2050. This is much higher compared to a 0.1% forecasted growth for Residential and 0.5% forecasted growth for Commercial customers.

CUB would like to comment on the following aspects of the industrial load forecast:

- i. The choice of economic driver in the regression model
- The relative weight of industrial load compared to residential and commercial loads in PGE's net system load forecast
- iii. The treatment of Direct Access (DA) customers in their net system load forecast

Each of the above comments is discussed in detail below:

In Appendix H of the draft IRP, PGE presents a list of variables and their descriptions. These variables are used as independent variables for the regression models for various customer classes. For example, the draft states that US GDP is used as the main driver behind PGE's industrial energy deliveries forecast.<sup>2</sup>

<sup>&</sup>lt;sup>1</sup> 2019 Draft IRP, Appendix H, Section H.1.3.1, p221, Equation 2

<sup>&</sup>lt;sup>2</sup> 2019 Draft IRP, Appendix H, Section H.1.2.4, p219

It is unclear whether PGE eventually uses US GDP as a variable in the industrial model. The industrial model<sup>3</sup> equation includes the variable GDPR and interprets it as *Real Oregon Gross Domestic Product*. CUB would like the variable used to be clearly described in the final IRP.

PGE's draft IRP<sup>4</sup> notes that the largest industrial segment in PGE's service area has transformed from being primarily lumber and paper manufacturing to hightechnology sector, and especially that semi-conductor manufacturing and data centers are the key drivers of PGE's industrial load growth. CUB would like more information on this transition and the resultant impact on industrial load growth.

CUB proposes that the Company explore including Oregon Non-Farm Employment data in the industrial regression model. This variable is included in the commercial sector forecast model but not in the industrial sector model. Is there a reason why PGE does not include this variable in their industrial load forecast? As a reference, PacifiCorp's 2017 IRP<sup>5</sup> shows that the company included forecasts for Oregon's nonfarm employment as the main economic driver for their industrial load forecast.

Finally, we would like to refer to a study on electric utility load forecasting in IRPs by Corvallo et. al (2016)<sup>6</sup>. The authors analyze load forecasting methodologies used in past IRPs of several utility companies including PGE and find evidence of persistent overestimation of load growth. They also find the "over-optimism regarding the recovery

<sup>&</sup>lt;sup>3</sup> 2019 Draft IRP, Appendix H, Section H.1.3.3, p222

<sup>&</sup>lt;sup>4</sup> 2019 Draft IRP, Chapter 4, Section 4.1.1.2, p 67

<sup>&</sup>lt;sup>5</sup>Pacificorp's 2017 IRP, Appendix A, p14.

http://pacificorp.com/content/dam/pacificorp/doc/Energy\_Sources/Integrated\_Resource\_Plan/2017\_IRP/2017\_IR P\_VolumeII\_2017\_IRP\_Final.pdf

<sup>&</sup>lt;sup>6</sup> Juan Pablo Carvallo, Peter H. Larsen, Alan H. Sanstad, Charles A. Goldman, October 2016, "Load forecasting in Electric Utility Integrated Resource Planning" (LBNL-1006395), Energy Analysis and Environmental Impacts Division, Ernest Orlando Lawrence Berkeley National Laboratory.

of the US Economy post 2008-2009 recession to be the main driver behind persistent overestimation of load growth" during their study period.

CUB's recommendations:

- a. Clarify if PGE is using US real GDP forecast or Oregon real GDP forecast in the industrial energy deliveries model
- Explore alternative economic drivers for industrial load growth scenarios in PGE's service area. CUB proposes including the Oregon non-farm employment variable in the industrial forecast rather than US GDP.
- ii. The industrial load growth has a much larger share in PGE's overall load growth forecast. The AAGR for Industry is 1.9% compared to a 0.1% for Residential and 0.5% for Commercial customers.

The study by the Corvallo et. al (2016), finds that utilities with a larger share of industrial load in their mix generally had the largest forecast errors. According to them, the highly elastic and lumpy nature of industrial customer load could be contributing factors along with the high uncertainty related to the entry and exit of industrial customers from the utility's service area.

CUB's recommendations:

- Separate out the industrial load from the total load forecast and conduct specific risk analyses.
- b. Provide more details on PGE's knowledge of industries entering and exiting their service area.

iii. CUB is concerned that there is no attempt to distinguish between small commercial and industrial customers and large commercial and industrial customers. A premise of New Load Direct Access is that the utility does not plan for new customers over 1MWa. However, PGE's forecast makes no attempt to exclude those customers. They are included in the load forecast, which is the basis for the renewable glide path and other resource acquisitions.

2) The Base Load forecast: Although the draft explains that the base load forecast is essentially the top down forecast adjusted to exclude the impacts of cost effective EE savings and the assumptions for the embedded distributed PV generation and electric vehicle load, it is not clear from table 4-6<sup>7</sup>, how the base load forecast numbers are derived. Are these estimates from a regression model? The adjustments for the EE, DER and EV-s are applied to the base load forecast again to obtain the total load forecast.

#### Please provide details of the base load forecast calculation.

#### B. Distributed Resource Flexible Load Study

# CUB would like to comment on the solar PV adoption forecasts by customer segments as presented in the report.

This study was conducted by Navigant; CUB would like to comment on the forecasted growth of solar PV adoption by customer segment.

Figure 4-5 in the draft<sup>8</sup> shows the Reference case for behind-the-meter solar adoption by customer type. As is seen in the figure, there is a steady growth in solar PV adoption in

<sup>&</sup>lt;sup>7</sup> 2019 Draft IRP, Chapter 4, Table 4-6, p80

<sup>&</sup>lt;sup>8</sup> 2019 Draft IRP, Chapter 4, Figure 4-5, page 75

general between 2020-2050. This growth is said to be driven primarily by increasing adoption by single-family residential and commercial customers. There is limited growth in other customer classes due to "logistical limitations" for other customer classes. CUB can foresee a future in that many of these limitations could become relaxed in the future. As more and more industrial customers are buying renewable energy CUB could see industrial customers lobbying for fewer limitation on PV adoptions for industrial customers. It is good corporate image for industrial customers to have solar PV installations in their industrial facilities. CUB recommends that PGE run a case in the high scenario with no or limited constraints for the industrial customers.

CUB's recommendation:

PGE evaluate incorporating a sensitivity analyses for a High PV adoption scenario with no constraints on industrial customers.

#### C. Voluntary Renewable Program Sensitivities

# CUB would like to comment on the implications of the voluntary renewable program sensitivity analysis.

The 2019 Draft IRP includes sensitivity analyses for the green tariff and Community Solar programs. Following the analysis, the draft states that "there is a very low likelihood that these updates would materially impact PGE's near-term capacity and RPS needs. PGE also considered potential uncertainties related to voluntary program participation and our energy position in the design on the Action Plan."<sup>9</sup>

<sup>&</sup>lt;sup>9</sup> 2019 Draft IRP, Chapter 4, Section 4.7, page 99

CUB would like to know if the material impacts referred to in this analysis have been updated following the recent expansion in their green tariff program. CUB would also like more information on how the "potential uncertainties" were included and analyzed in this sensitivity exercise.

### Attachment A: 2019 IRP Stakeholder Comment Record

June 17, 2019

Organization: Alliance of Western Energy Consumers

IRP Topic(s) and/or agenda item(s): Comments on draft 2019 IRP

Comment: As requested, attached are AWEC's comments on PGE's Draft IRP.



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June 17, 2019

Elaine Hart Manager, Integrated Resource Planning Portland General Electric Company Elaine.Hart@pgn.com

Re: Portland General Electric 2019 Draft Integrated Resource Plan

Dear Elaine,

Thank you for the opportunity to provide comments on Portland General Electric Company's ("PGE" or "Company") 2019 Draft Integrated Resource Plan ("IRP"). The Alliance of Western Energy Consumers ("AWEC") recognizes and appreciates the substantial work PGE's IRP team has undertaken both to develop the Draft IRP and to communicate with stakeholders over the many IRP workshops PGE has held. AWEC's comments below are based on a preliminary review of PGE's Draft IRP. AWEC may address other issues in comments on the Company's Final IRP after it has fully reviewed the document.

#### A. Renewable Action Plan

PGE's renewable resource action plan calls for another 150 aMW of new renewable resources by 2023, modeled as Gorge and Montana wind. In PGE's 2016 IRP, AWEC opposed the Company's action plan to acquire new renewable resources significantly ahead of the date such resources were needed. PGE proposes a similar strategy in this Draft IRP and AWEC's position has not materially changed. Indeed, the case for near-term action to acquire additional renewable resources appears less compelling, not more. PGE projects that it will be physically compliant with the RPS through 2030, and compliant until 2037 through use of its REC bank. Although not explicitly stated, AWEC assumes that PGE's analysis does not incorporate any unbundled REC purchases, which would further push out the need for additional RPS resources. Meanwhile, the value of these resources has declined with the reduction to the Production Tax Credit, thereby further minimizing the case for another near-term acquisition.

AWEC does take note that PGE has identified Montana wind as a potential resource opportunity. AWEC agrees that there is at least the potential for a compelling opportunity to exist there, but emphasizes that such an opportunity should be truly extraordinary to proceed at this time. Additionally, PGE itself appears to be uncertain of its ability to acquire this resource AWEC Comments on PGE Draft IRP June 17, 2019 Page 2

with current transmission constraints and, therefore, AWEC questions whether PGE's action plan is achievable.

Of additional concern to AWEC is the indirect impact PGE's renewable action plan may have on customer costs. As PGE is aware, it has seen an explosion of requests for contracts from Qualifying Facilities, due to the high avoided costs the OPUC has established for PGE. The primary driver of these high avoided costs has been the renewable resource deficiency date, and the associated deficiency prices. Following PGE's 2016 IRP, the Commission established a new renewable resource deficiency date of 2025, even though PGE could have demonstrated that it had the ability to achieve compliance with the RPS until 2037.<sup>1/</sup> In its compliance filing in UM 1728 following the Commission's approval of updated avoided costs on September 18, 2017, the on-peak renewable price for a solar QF jumped from \$36.16 to \$103.83. While these prices have declined since then, they are still \$73.86 in 2025. This represents an obviously attractive price for a QF developer, and AWEC is concerned that PGE's continuation of its near-term RPS procurement strategy will also continue to drive artificially high avoided cost prices that will attract more QF development and ultimately increase costs to customers. AWEC does not consider this to be a prudent resource procurement strategy.

### **B.** Capacity Action Plan

PGE identifies a capacity need of 685 MW by 2025, which it proposes to fill with energy storage and bilateral contracts for existing resources. At this time, AWEC takes no position on the amount of the capacity need PGE has identified and will continue to investigate this issue.

AWEC supports PGE's efforts to identify low-cost opportunities for existing resources, similar to the contract it entered into with BPA. PGE does not, however, appear to have analyzed two other potentially low-cost opportunities for capacity: long-term direct access and transmission redirection.

As AWEC has demonstrated in other dockets (e.g., UE 335), long-term direct access presents a potential least-cost, least-risk means of meeting projected capacity deficits. By allowing load to leave PGE's system, that reduces PGE's capacity need, thus avoiding or deferring higher cost capacity procurements. While PGE studied the potential reliability impacts of long-term direct access load on its provider of last resort obligations (discussed further below), it did not evaluate this alternative benefit of direct access to bundled service customers. AWEC believes that any least-cost, least-risk plan should consider and evaluate this option.

Similarly, AWEC encourages PGE to evaluate whether it can redirect some of its transmission rights to access firm market power that will meet a portion of its projected capacity need in a low-cost manner. AWEC has no information as to whether such an option is either feasible or economic for PGE, but raises this issue because Puget Sound Energy performed an analysis of redirecting its transmission rights in its 2017 IRP and found that it provided a least-cost capacity solution. See PSE 2017 IRP at 1-19 & Appen. G. PGE should undertake a similar analysis and, if such an option is infeasible, demonstrate why.

<sup>&</sup>lt;sup>1</sup>/ Docket LC 66, Comments of Bradley G. Mullins for AWEC at 2-4 (Dec. 1, 2017).

AWEC Comments on PGE Draft IRP June 17, 2019 Page 3

Finally, AWEC notes that PGE identifies no intention to construct additional gas-fired generation in the near- or long-term, or another resource that provides incremental capacity to the region and can meet reliability needs over an extended period. While AWEC understands this decision from a policy and risk perspective, PGE has raised concerns about the reliability of the grid on a number of occasions, particularly with regard to load on its direct access programs and the state of regional resource adequacy. It does so again in the Draft IRP. Energy storage is effective at meeting short-term capacity needs, but not necessarily for meeting long-term needs lasting multiple days. If PGE is unwilling to secure the type of capacity necessary to ensure this type of reliability for its cost-of-service customers, this diminishes the benefits for large customers of taking service from PGE as compared to a third party.

### C. Direct Access Capacity Adequacy Sensitivities

The Draft IRP includes a loss of load probability ("LOLP") study associated with PGE's POLR requirement for long-term direct access customers. Draft IRP § 4.7.3.1. This study shows that PGE would need an additional 526 MW of capacity to maintain a traditional 1-in-10 LOLP in the event that it was required to serve these customers. While not stated, AWEC assumes such a requirement would appear on an emergency basis only, as the current direct access program requires at least three years of notice for a direct access customer to return to PGE's service.

AWEC understands PGE's concerns associated with the need to serve a significant amount of load on an emergency basis, but questions whether PGE's apparent proposed strategy to acquire additional capacity that, it appears, would be used for no other purpose represents a least-cost, least-risk solution to this concern. Rather, the most cost-effective solution appears to be for PGE to request to modify its curtailment policy to allow it to curtail long-term direct access customers first during a reliability event. This is how Puget Sound Energy treats its direct access customers under its Schedule 449 and would obviate the need for PGE to obtain additional capacity – capacity it will charge for, but will rarely, if ever, use.

AWEC appreciates PGE's request for comments on its Draft IRP and looks forward to working with PGE through the regulatory process after its Final IRP is filed.

Sincerely,

<u>/s/Tyler C. Pepple</u> Tyler C. Pepple 1750 SW Harbor Way, Suite 450 Portland, Oregon 97201 (503) 241-7242 (phone) (503) 241-8160 (facsimile) tcp@dvclaw.com Of Attorneys for the Alliance of Western Energy Consumers

### Attachment A: 2019 IRP Stakeholder Comment Record

June 17, 2019

Organization: Absaroka Energy

IRP Topic(s) and/or agenda item(s): Comments on draft 2019 IRP

Comment: Attached to this email is GB Energy Park, LLC's comments for Portland General Electric's Draft 2019 Integrated Resource Plan

### PORTLAND GENERAL ELECTRIC DRAFT 2019 INTEGRATED RESOURCE PLAN



### COMMENTS PROVIDED BY

GB Energy Park, LLC

SUBMITTED June 17, 2019

Comments on Portland General Electric's Draft 2019 Integrated Resource Plan Page 1 of 9

## Comments of GB Energy Park, LLC on Portland General Electric's Draft 2019 Integrated Resource Plan (IRP).

These comments are offered by GB Energy Park, LLC (GBEP), developer of the Gordon Butte Pumped Storage Hydro Project (Gordon Butte PSH or Project), in response to Portland General Electric's (PGE) Draft 2019 Integrated Resource Plan (2019 Plan; Plan). GBEP is a single-purpose subsidiary of Montana-based Absaroka Energy Development Group, LLC.

#### Introduction

After reviewing PGE's 2019 Plan, GBEP largely agrees with the analysis methods, results, the preferred portfolio, and procurement strategies set forth in the Plan. GBEP's independent efforts and analyses have resulted in many of the same conclusions set forth in the 2019 Plan, including the following:

- The ongoing and profound changes in electricity markets will require a combination of additional customer resources, renewable generation, and flexible capacity to maintain the long-term health, sustainability, and serviceability of PGE's system.<sup>1</sup>
- There are "significant uncertainties regarding long-term [natural gas] prices and the cost of emissions" as well as "short-term risks associated with fuel availability."<sup>2</sup>
- High quality resources, such as Montana-based wind generation, will provide significant value due to their "attractive capacity factors" and their complementary seasonal, diurnal, and geographic diversity from PGE's existing resources.<sup>3,4</sup>
- Preferred portfolios selected strictly on the calculated cost and risk metrics can be "overly precise and overly prescriptive" and should instead "[preserve] flexibility to pursue various technologies and resource locations."<sup>5</sup>
- Highly flexible, fast-acting, utility-scale, and long-duration closed-loop pumped storage is a proven technology that is an ideal solution to many of the needs identified in the 2019 Plan. Modern pumped storage hydro will provide the necessary flexibility to adapt to changing markets because of its diverse operational capabilities and ability to provide multiple services to the grid.

As noted in the Plan, PSH projects require specific siting criteria and are difficult and timeintensive to develop.<sup>6</sup> However, PGE can capitalize on the unique opportunity to procure a portion of, or all of, the fully developed, licensed, and construction-ready Gordon Butte PSH project.

<sup>&</sup>lt;sup>1</sup> P.194 of the 2019 Plan

<sup>&</sup>lt;sup>2</sup> P.119 of the 2019 Plan

<sup>&</sup>lt;sup>3</sup> P.114 of the 2019 Plan

<sup>&</sup>lt;sup>4</sup> P.126 of the 2019 Plan

<sup>&</sup>lt;sup>5</sup> P.177 of the 2019 Plan

<sup>&</sup>lt;sup>6</sup> P.110 of the 2019 Plan
Comments on Portland General Electric's Draft 2019 Integrated Resource Plan Page 2 of 9

# Advanced Pumped Storage Hydropower's Compatibility with the 2019 Plan

In its 2019 Plan, PGE identified a three-part preferred portfolio which aims to deliver adaptability in their planning and resource acquisition processes. The three-part portfolio is comprised of capacity, customer, and renewable resource additions. GBEP would like to highlight the capability of PSH to simultaneously accommodate each of these portfolio components and to enable PGE to achieve their goal of maintaining robust, yet flexible, resource planning and acquisition processes.

# Capacity Resource Additions

As PGE determined in the capacity resources portion of their 2019 plan, PSH is an ideal resource to fulfill the identified dispatchable flexible capacity needs.<sup>7</sup> Throughout the electric utility industry, forward-looking utilities are evolving away from a resource portfolio dominated by conventional generation resources toward more flexible assets, including energy storage, as a critical component of a least-cost resource mix.<sup>8</sup> Modern, fast-responding pumped storage hydropower is recognized as the most capable, cost-effective, and proven utility-scale energy storage technology in the world.<sup>9</sup> Not only is it capable of satisfying the needs for capacity, flexibility, ramping and dispatchability that Portland General Electric identifies in the 2019 Plan, *it is the ideal solution* to provide these services and a suite of many other services including:

- Peaking capacity
- Energy storage
- Energy arbitrage
- Integration and firming of existing and future renewables
- Ancillary services, including
  - Regulation Up and Regulation Down
  - Load-following
  - Spinning and non-spinning reserves
  - o Black start
  - Voltage and Frequency Control
  - o System Inertia
  - $\circ$  INC / DEC

This diverse array of abilities, services, and operational schemes offered by PSH would also assist PGE in achieving their goal of remaining adaptable in the ever-changing energy landscape by enabling them to use PSH as a tool to satisfy a wide variety of needs even if those needs change drastically from year to year.

<sup>&</sup>lt;sup>7</sup> P.195 of the 2019 Plan

<sup>&</sup>lt;sup>8</sup> <u>https://www.greentechmedia.com/articles/read/pacificorps-march-from-coal-toward-clean-energy-alternatives?utm\_medium=email&utm\_source=Daily&utm\_campaign=GTMDaily#gs.9cg4sq</u>

<sup>&</sup>lt;sup>9</sup> <u>http://www.nwhydro.org/wp-</u> <u>content/uploads/events\_committees/Docs/2016\_Pumped\_Storage\_Workshop\_Presentations/4%20-%20Patrick%20Balducci.pdf</u>

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### Customer Resources

The other component of the 2019 Plan that is consistent with the benefits provided by PSH is the need for standby generation, dispatchable storage, and general flexibility identified in the customer resources portion of the Plan. Although PGE intends to satisfy these needs through cost-effective customer participation, these resources could also be supplemented or completely satisfied via a PSH facility. For instance, a portion of a PSH facility could be dedicated towards the aforementioned capacity needs while still remaining immediately available to provide a substantial amount of standby generation or dispatchable storage – one of many examples of how a PSH facility could support PGE's goal of a robust and flexible resource future.

# Renewable Resource Additions

In addition to being a proven, reliable, and cost-effective solution for PGE's capacity and flexibility needs, PSH also fits in well with the renewable resource additions portion of the preferred portfolio. Advanced PSH is an ideal counterpart to integrate variable energy resources (VERs) such as wind or solar. The fast-acting flexibility provided by modern pumped storage technology and equipment configurations enables the latest generation of PSH to be an extremely effective tool for integrating renewable resources by creating a firm, shaped, reliable, and dispatchable renewable energy product. Not only does this directly improve the reliability and value of these renewable energy products, it also acts as a catalyst for further development of renewables by optimizing the use of, and reducing the burden on, existing transmission infrastructure – mitigating the need for costly transmission upgrades. Figure 1 below illustrates the ability of PSH to support existing renewable projects as well as stimulate additional renewable development.

A more detailed discussion of how the PSH facility will interact with VERs is provided in the following section.



Figure 1 – Rendering of existing and proposed wind development in the Musselshell River Valley near the Gordon Butte Pumped Storage Project.

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# Case Study – Analyzing Montana Wind Paired with PSH

To further evaluate the compatibility of PSH with PGE's preferred portfolio, GBEP has investigated the ability of advanced PSH to be paired with a Montana wind product to provide firmed, dispatchable on-peak clean energy.

To visualize and understand the behavior and value of PSH technology, GBEP developed a basic modeling system to simulate the operation and effects of a pumped storage system paired with generation from renewable resources. The model allows the user to enter 10-minute wind production data and specify the physical parameters (size, duration, efficiency, etc.) of the storage facility as well as provide operational instructions (target output levels, pumping/generating preferences, etc.) and market conditions (peak hours, excess power availability, etc.) to influence and fine-tune the "decision-making" of the pumped storage facility.

Using this tool, GBEP evaluated the interaction of a 1/3 portion of the Gordon Butte Pumped Storage facility (134 MW turbine and 134 MW pump unit) paired with a single 230 MW wind farm located in central Montana. Actual 10-minute wind data was used to run the model. For off-peak energy storage, the simulated storage facility was allowed to make use of inexpensive nighttime power (up to 75 MW – as needed) in addition to the production of the 230 MW wind farm. GBEP then instructed the program to calculate capacity factors during peak hours. The table below compares the peak hour generation and capacity factors of the wind farm alone to those of the combined wind+PSH system.

Hour:	Wind Production	Wind Capacity	Wind + PSH	Wind + PSH
nour.	(GWh):	Factor (%):	Production (GWh):	Capacity Factor (%):
8	34.11	40.63%	68.32	81.38%
9	35.46	42.24%	68.83	81.99%
10	37.76	44.97%	69.93	83.30%
11	39.62	47.19%	71.08	84.67%
12	41.21	49.08%	70.79	84.32%
13	41.43	49.35%	64.20	76.48%
14	42.18	50.25%	61.09	72.77%
15	41.55	49.50%	57.81	68.86%
16	40.83	48.63%	54.90	65.40%
17	40.27	47.97%	53.25	63.44%
18	38.87	46.30%	50.85	60.57%
19	36.82	43.86%	48.41	57.67%
20	34.73	41.36%	44.81	53.38%
21	32.59	38.82%	41.56	49.51%
ON-PEAK AVERAGE	38.39	45.73%	58.99	70.27%

Table 1. Results of wind and PSH on-peak capacity factor modeling.

These results clearly show the value that PSH would add to renewables and PGE's system; demonstrated by the significant boost that a pumped storage system provides during critical peak hours. This boost is the result of PSH's ability to store inexpensive energy

Comments on Portland General Electric's Draft 2019 Integrated Resource Plan Page 6 of 9

from the wind farm and energy markets during off-peak hours. This, in effect, creates a dispatchable and completely renewable generation resource.

What is not shown in the model is using the allocated share of Gordon Butte to not only shape and dispatch the wind, but to also provide other services such as regulation, standby generation, and many other valuable services. GBEP would like the opportunity to work with the utility to better model the PSH facility and its interactions with variable energy resources to quantify the cost/benefit opportunities of using a slice of, or the entirety of, the PSH for PGE's system.

Lastly, it is important to note that the model is limited in its ability to fully quantify the benefits that will be provided by a pumped storage facility. For instance, the simulation developed by GBEP relies on a relatively small amount of input data (wind farm production, target values, and facility parameters) and does not accommodate additional data such as forecasted weather or transmission system data or variations in daily load patterns. The model also does not account for the PSH's ability to perform other services such as regulation and ancillary services and does not account for the added benefit of regional resource diversity. GBEP would welcome the opportunity to work directly with Portland General Electric to more holistically model the Gordon Butte PSH in their system to see how the facility is able to provide value to PGE's system and, at the same time, solve the issues identified in the 2019 Plan.

# Gordon Butte Pumped Storage Hydro Project

In response to the 2019 Plan's identification of PSH as a preferred capacity resource, and in response to the above commentary, a brief overview of the 400 MW, closed-loop (see footnote),<sup>10</sup> Gordon Butte Pumped Storage Hydro Project is provided below to reiterate the ability of PSH to fit seamlessly into the preferred portfolio provided in the 2019 Plan.

Gordon Butte is an advanced pumped storage hydro facility with 3,400 MWh of storage capability to be interconnected to the Colstrip 500 kV transmission lines near Martinsdale, Montana. The Project will employ the latest Quaternary equipment technology to provide fast-ramping flexible capacity ideally suited for integrating intermittent renewable resources into the Pacific Northwest transmission grid. Gordon Butte, coupled with Montana's robust wind resources, provides a reliable, cost-competitive, and carbon-free solution to the needs identified in the 2019 Draft Plan. The Gordon Butte PSH project is:

• **CONSTRUCTION READY:** The Gordon Butte PSH has received its 50-year hydropower license from FERC, completed its NEPA environmental review (Environmental Assessment with Finding of No Significant Impact), completed all the necessary permitting, secured the land and water (Montana State issued Water Right), finalized its engineering design, finalized equipment selection and design (General Electric Renewable Energy), and has engaged the Engineering,

<sup>&</sup>lt;sup>10</sup> A recent action by the Eightieth Legislative Assembly of the State of Oregon (SCR 1-A) specifically encourages Oregon Regulators and Utilities to support and utilize closed-loop PSH projects in their resource mixes in order to meet capacity needs.

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Procurement and Construction team (Ames Construction, Black & Veatch) that will build the project.<sup>11</sup>

- WATER: GBEP has received a Permit to Appropriate Water (40A 30069150) from the Montana Department of Natural Resources and Conservation, with a priority date of July 30, 2014. This water right will be utilized for the initial fill of the lower reservoir and annual maintenance fills to address losses due to evaporation and seepage (estimated 400 acre-feet) for the Project's operation. GBEP has also executed an agreement with the Project site landowner to utilize existing diversion and irrigation infrastructure for the conveyance of water to the lower reservoir. The Montana Department of Environmental Quality has issued GBEP a waiver on the 401 Water Quality Permit, as there will be no water discharge from the facility.
- LAND: The Project is located on private land, part of a large ranch (approximately 50,000 acres) owned and controlled by a single landowner. The careful selection of this Project site ensures that it will not adversely affect any of Montana's protected lands. GBEP has a positive relationship with the landowner and has executed an agreement to acquire the land and easements necessary to build and operate the Project.
- INTERCONNECTION: Gordon Butte PSH is nearing the end of its interconnection process to connect into the Colstrip twin-500 kV transmission line, which runs from the Colstrip Generation Station in eastern Montana to load markets in Washington, Oregon and California. This line, located approximately 6 miles to the south of the Project, is co-owned by five large regional utility companies NorthWestern Energy, Puget Sound Energy, Portland General Electric, Avista Corp and PacifiCorp and forms the transmission backbone of the Pacific Northwest grid.
- UTILITY-SCALE: <u>A utility such as PGE can contract for the portion of the Project</u> <u>that best fits its needs</u>. The facility has been designed to accommodate multiple operators. Should Portland General Electric acquire or contract for a share of the Project, there are multiple ways that the remaining capacity could be allocated. The facility will have three-unit pairs. Each pair will include a separate pump and turbine, each with a dedicated 134 MW motor and a 134 MW generator, respectively, for an installed capacity of 400 MW with 3,400 MWh hours of storage – or 8.5 hours at continual maximum discharge for 400 MW. Each unit pair will have the capability to be operated independently from one another.
- FAST-ACTING: The pumps and turbines will be Quaternary units configured in a

<sup>&</sup>lt;sup>11</sup> The major milestones achieved to date: Land Agreement in Place for Project and Easements, MT State Issued Water Right Permit Obtained, 401 Water Quality Certification Waived – No Water Discharge, NEPA Environmental Assessment – Finding of No Significant Impact, Front End Engineering Design Completed, FERC License Issued (P-13642), FERC License Article Compliance Current, Equipment Selection and Design, Key Subcontractors and Vendors, EPC Team, Interconnect Feasibility and System Impact Studies Completed

# Comments on Portland General Electric's Draft 2019 Integrated Resource Plan Page 8 of 9

hydraulic short-circuit. This will allow the facility to operate pumps and turbines simultaneously and independently and switch seamlessly from pumping to generating mode. The facility will be able to ramp at an estimated rate of 20+ MW/sec in either direction (Figure 2).<sup>12,13</sup>



Figure 2 - 24-hour operational profile of a single ternary unit at the KOPS II Pumped Storage Hydro Facility in Austria.<sup>14</sup>

• **FLEXIBLE**: The operational versatility of the units will allow PGE to utilize the facility for flexible capacity, as well as a wide-ranging suite of grid operation services enabling them in their pursuit of a flexible, robust, affordable, clean, and secure energy future.

# Conclusion

GBEP is grateful for the opportunity to actively participate in and provide input to the 2019 resource planning process and believes that the current 2019 Draft Plan adequately assesses customer and stakeholder input and promotes a forward-thinking strategy. GBEP looks forward to participating in future Request for Proposals.

<sup>&</sup>lt;sup>12</sup> The GBEP equipment configuration has earned attention of the hydropower industry and was picked up by the U.S. Department of Energy for the analysis of grid support and economic benefits based on its fast-acting capabilities. https://www.energy.gov/eere/articles/pumped-storage-projects-selected-techno-economic-studies

<sup>&</sup>lt;sup>13</sup> Dong, Zerui, et al. "Modeling of Quaternary Pumped Storage Hydropower (Q-PSH) for Power System Studies." 2019.

<sup>&</sup>lt;sup>14</sup> The Quaternary units proposed for the Gordon Butte PSH Project will provide similar, but faster, operational abilities than the Ternary Units.

# For more information:

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FERCs involvement with the project can be found on the FERC eLibrary at: www.ferc.gov/docs-filing/elibrary.asp using docket number: P-13642

# Attachment A: 2019 IRP Stakeholder Comment Record

June 17, 2019

Organization: NW Energy Coalition

IRP Topic(s) and/or agenda item(s): Comments on draft 2019 IRP

Comment:

Please find attached our comments on the draft IRP. We look forward to further discussion on these points as well as many other aspects of the 2019 IRP.

Affiliated Tribes of Northwest Indians AirWorks, Inc. Alaska Housing Finance Corporation Alliance to Save Energy Allumia Alternative Energy Resources Organization Ameresco American Rivers Backbone Campaign Beneficial State Bank BlueGreen Alliance Bonneville Environmental Foundation Byrd Barr Place Citizens' Utility Board of Oregon City of Seattle Office of Sustainability & Environment CleanTech Alliance Climate Smart Missoula Climate Solutions Community Action Center of Whitman County Community Action Partnership Assoc. of Idaho Community Action Partnership of Oregon Farth and Spirit Council Earth Ministry Ecova eFormative Options Energy350 Energy Savvy Energy Trust of Oregon Environment Oregon Environment Washington EQL Energy Forth Global Ocean Health Home Performance Guild of Oregon Housing and Comm. Services Agency of Lane Co. Human Resources Council, District XI Idaho Clean Energy Association Idaho Conservation League Idaho Rivers United Interfaith Network for Earth Concerns League of Women Voters Idaho League of Women Voters Oregon League of Women Voters Washington Montana Audubon Montana Environmental Information Center Montana Renewable Energy Association Montana River Action National Center for Appropriate Technology National Grid Natural Resources Defense Council New Buildings Institute Northern Plains Resource Council Northwest EcoBuilding Guild Northwest Energy Efficiency Council NW Natural OneEnergy Renewables Opower Opportunities Industrialization Center of WA **Opportunity Council** Oregon Energy Fund Oregon Environmental Council Oregon Physicians for Social Responsibility OSEIA OSEIA Pacific Energy Innovation Association Pacific NW Regional Council of Carpenters Portland Energy Conservation Inc. Portland General Electric Puget Sound Advocates for Retired Action Puget Sound Cooperative Credit Union Renewable Northwest Save Our wild Salmon Seattle City Light Seinergy Sierra Club Sierra Club, Idaho Chapter Sierra Club, Montana Chapter Sierra Club, Washington Chapter Small Business Utility Advocates Smart Grid Northwest Snake River Alliance Solar Installers of Washington Solar Oregon Solar Washington South Central Community Action Partnership Southeast Idaho Community Action Partners Spark Northwest Spokane Neighborhood Action Partners Sustainable Connections The Climate Trust The Energy Project Transition Missoula UCONS LLC Union Of Concerned Scientists United Steelworkers of America, District 12 Washington Environmental Council Washington Local Energy Alliance Washington Physicians for Social Responsibility Washington State Department of Commerce Washington State University Energy Program YMCA Earth Service Corps Zero Waste Vashon



June 17, 2019

- From: NW Energy Coalition
- To: Portland General Electric

Comments on 2019 Draft IRP

The NW Energy Coalition (NWEC) appreciates the opportunity to provide comments on the draft 2019 PGE IRP.

We applaud the comprehensive presentation in the draft. Many elements have been significantly refined since the 2017 IRP and there is better cohesion among the many elements in the modeling and assessment. We will not comment on all aspects here but highlight some thematic comments and provide some specific requests and suggestions.

We believe PGE has provided a clear direction for addressing the many uncertain aspects of future load, resource, operational and market considerations. In particular, the draft provides a solid approach for the action plan period through 2025, and then focuses on preserving and extending optionality from the mid-2020s onward, building on proposed actions going forward.

• NWEC generally agrees with the statement (p. 91) that PGE "conservatively identified 250 MWa as a reasonable maximum energy addition size for consideration in designing the Action Plan in this IRP. This assumption accounts for additional uncertainties not contemplated in this analysis and for the potential impacts of additional customer decisions that may affect PGE's energy position." However, we highlight the need to consider this as a starting point and that a different level of Action Plan resource acquisitions may be needed with further refinement.

• NWEC also agrees with PGE's position (p. 93) that "it is appropriate to apply a minimum standard of physical RPS compliance in its long-term planning process and to use the REC bank to mitigate compliance risks and achieve cost reductions on a year-to-year basis depending on loads, renewable generation, and market conditions," as well as the importance of using the combination of the IRP glide path analysis and a structured and periodic

Comments of NW Energy Coalition PGE 2019 Draft IRP June 17, 2019 – Page 2

approach to new resource acquisition to stay on pace for acquiring between 25 and 58 aMW per year beginning in 2022 to ensure RPS compliance by 2040.

- We agree with the draft's conclusion (p. 85) that the "wide range of potential future conditions necessitates a near-term procurement plan for capacity that is both flexible enough to respond to changing conditions and robust enough to provide an avenue for significant capacity procurement if it is needed." Among other aspects, the draft is notable in dramatically expanding the role of battery storage in response to a fast changing capacity and flexibility need starting in 2021. We agree with the draft analysis that this is appropriate but needs a good deal more in-depth assessment on the cost and operational characteristics of large scale battery resources. In addition, however, we urge more in-depth assessment as well of flexible demand strategies including advanced energy efficiency and demand response. The currently projected capacity contribution of demand side resources should be seen as a floor, not a ceiling. We believe a balanced and diverse strategy for acquiring non-emitting capacity resources across both supply and demand realms is the best way forward, especially given the rapidly increasing importance of resource adequacy as well as fundamental uncertainties about scale and timing, including the ability to roll over or extend existing hydro capacity contracts and the likely tightening of the regional markets (Mid-C and possibly EDAM) for short-term energy.
- We also anticipate a need for rapid reassessment of the regional context if the EIM Extended Day Ahead Market (EDAM) proposal goes forward. Since the initial assessment by EIM participating balancing areas including PGE is expected to be released shortly, there may be time to include at least some general context in the 2019 IRP, but we expect that if the assessment shows a positive result, additional work will be needed on EDAM design before it can be incorporated into IRP review, perhaps during the next IRP Update.
- At various places in the draft, PGE employs a variety of resource adequacy values, including Loss of Load Probability (LOLP), Loss of Load Expectation (LOLE) and Loss of Load Hours (LOLH). We believe the final IRP would benefit from a short discussion of how these metrics are different and why each of them is used for particular parts of the analysis.
- We thank PGE for including "error bars" (ranges of variance) in all appropriate charts in the draft. This greatly helps understanding the tradeoffs involved.

Further comments by section:

Section 3.2.1

NWEC expects that within 5-10 years, the long rise of shale gas in North America will level out, and demand factors such as rapidly increasing LNG exports will cause a tightening of supply and demand. In addition to raising commodity gas prices overall, we believe this will have an additional effect on gas prices in this region because markets to the east will open up again for gas from British Columbia and Alberta, and switch

Comments of NW Energy Coalition PGE 2019 Draft IRP June 17, 2019 – Page 3

the price differentials at AECO and Sumas, which have been generally below Henry Hub, to a premium compared to Henry as they were prior to about 2013.

We think it would be appropriate to test the leading IRP scenarios with a higher gas price sensitivity (either the indicated High Gas Price trend or somewhat more moderate prices, such as \$4.50/mmBtu in 2025 and \$6.00 in 2030 for Sumas), to see what effects that has on regional market prices and dispatch as well as within PGE's own system, and impact on the relative value of new clean resources.

# 3.2.3 High Renewable WECC Future

This section makes reference to the Wood Mackenzie Base Case WECC data base. Is that based on WECC data (the Anchor Data Set, etc.), or is it a separately compiled dataset?

# 3.3 Technology Cost Future

NWEC remains concerned about some of the technology price projections in the draft. In particular, utilityscale solar is shown (Figure 3.8) to have a reference cost decline to about 82% of current costs by 2030 and 78% by 2040, which is in line with the NREL Advanced Technology Baseline. The ATB is the most sophisticated assessment available for technology cost drivers. However, our view (using the NWEC Simple Solar Calculator provided to PGE) is that solar cost declines could be more in the range of 70% of current cost in 2030 and 50% in 2040 (which in turn is higher than the Low range in the draft). Because of the likely importance of the solar resource going forward, as well as its ready availability in the state of Oregon, we think this issue needs further study, in part to see where the ATB analysis might be updated, and to better understand the apparent difference in capital cost estimates (which our solar calculator uses) and the LCOE approach in the ATB.

# 4.7.3 Direct Access and Resource Adequacy

NWEC shares PGE's concern about the impact of any significant increase in direct access by large customers and potential cost or risk shifting to ongoing cost-of-service customers.

# 5.3.1 Wind Power

NWEC is concerned about the capacity factors reported in Table 5.6 for wind reference plants at various points in the Northwest. The values for Ione, Oregon (32.7%) and Montana (42.9%) are reasonable, but the values for Columbia Gorge (40.8%) and Southeast Washington (42.9%) seem too high. While there is a considerable range for different sites, the NW Power and Conservation Council and other assessments generally find "Columbia Gorge" (i.e., east of the Gorge along the Columbia River corridor) and southeast Washington/northeast Oregon wind to be in the 32-36% range, while the better Montana sites could be 44% or higher. We are interested in further technical review of this issue.

# 5.5.2 Transmission Uncertainties

NWEC understands that the discussion of transmission in the draft is still evolving. We see two key issues going forward: the prospect for transmission expansion to reach a wider range of east side Oregon solar resources, and the availability of existing transmission capacity for Montana wind as well as the longer-term prospects for transmission expansion (either Montana-Idaho-eastern Washington or central Montana-

Comments of NW Energy Coalition PGE 2019 Draft IRP June 17, 2019 – Page 4

southeast Idaho). NWEC agrees with the five design principles noted by PGE (p. 198), but we also think a more substantive approach to co-optimizing renewable and transmission development will be needed in the IRP and related processes. This will help make better use of the existing grid and also target transmission expansion as a long-duration, high cost but very high value infrastructure for supporting the very large quantities of new renewable resources needed from the mid-2020s onward.

# 6.1.3 Integration Costs

As indicated in our joint letter with Renewable Northwest to the company, we remain concerned about the assignment in Table 6.2 of a very high integration cost for Oregon solar (\$1.36/MWh compared to one-quarter of that for various wind resources).

# 7.2.2 Portfolio Scoring

We generally agree with PGE's approach (p. 177) of including actions and not a list of specific resources for the preferred plan – in this case, the Mixed Full Clean Portfolio. We also agree with the Preferred Portfolio Design Principles: (1) include all cost-effective energy efficiency and DER adoption and participation assumptions based on the DER Study; (2) allow up to 150 aMW of additional renewable resources in 2023 and/or 2024 (with higher amounts if less hydro capacity and energy can be contracted); and (3) constrain new capacity resource additions through 2025 to technologies that do not emit greenhouse gases.

# 7.3.2 Colstrip Sensitivities

The draft results show that a wind-oriented replacement strategy for Colstrip units 3-4 in 2027 scores better for every scoring metric (Cost, Variability, Severity). Given the recent passage of HB 5116 in Washington state that will lead to Puget Sound Energy removing coal from retail rates after 2025, we wonder if a revised analysis using a 2025 rolloff date rather than 2027 would show any important differences, particularly with the timing of capacity and energy acquisitions during the action plan period through 2025.

Thank you for your consideration of these comments. We look forward to further discussion about the elements, perspectives and action items in the PGE 2019 IRP.

Jund Sente

Fred Heutte Senior Policy Associate NW Energy Coalition 503.757-6222 fred@nwenergy.org

# Attachment A: 2019 IRP Stakeholder Comment Record

June 17, 2019 Organization: OPUC IRP Topic(s) and/or agenda item(s): Comments on draft 2019 IRP Comment: Please find attached Staff's comments on PGE's draft 2019 IRP.



SUBJECT:	Informal Feedback on Draft 2019 IRP
FROM:	Oregon Public Utility Commission, Energy Resource & Planning Division
то:	Portland General Electric IRP Team
DATE:	6/11/19

Oregon Public Utility Commission (OPUC or Commission) Staff appreciates the opportunity to provide early informal feedback to Portland General Electric (PGE or Company) on the Draft 2019 IRP. The draft IRP contains valuable insight into PGE's long-term planning, and answers some of Staff's questions about the preferred portfolio and action plan. Staff looks forward to continuing to work with PGE and stakeholders as the IRP process continues. The following are some of Staff's questions and concerns upon review of the draft 2019 IRP.

# **Action Plan**

Staff previously submitted comments on PGE's draft action plan on March 22, 2019. Staff appreciates the additional information provided in the draft 2019 IRP supporting the action items. Staff continues to analyze the action items and the additional information provided by PGE in the draft IRP.

 One concern, upon further review of the staged capacity procurement action item, is whether a staged procurement allows full consideration of large near-term capacity resources, such as pumped hydro. Staff hopes PGE will help demonstrate to stakeholders that it has fully considered whether procuring capacity from bilateral contracts in the near term will be more cost-effective than procuring a potential large capacity resource in the near term.

### Portfolio Analysis and Sensitivities

Staff appreciates PGE's inclusion of sensitivity analysis involving Colstrip 3 and 4 retirement in 2027.

- Because the results of the analysis show a potential savings of over \$200 million, Staff suggests PGE perform a rate impact analysis of the PVRR change of advancing the depreciation dates of these units to 2027.
- Staff additionally suggests PGE include the plan to perform this analysis as an action item in the IRP.

Staff notes that although PGE states in Section 5.3.1.3 that a sensitivity analysis regarding wind capacity factors is described in Chapter 7, Staff has not found an obvious mention of this analysis in Chapter 7 of the Draft IRP.

 PGE should describe this analysis more thoroughly in Chapter 7, or include the analysis if it has not been included already. Staff appreciates that the inclusion of non-traditional metrics in the IRP may be able to help inform the selection of a preferred portfolio. However, Staff may wish to engage in further discussion about some of the portfolios that have been screened out.

Staff will also be interested in further discussion and exploration of PGE's new two-stage portfolio construction methodology, which uses portfolios with assets that are fixed in the near-term.<sup>1</sup>

# **Emissions Forecasting**

Staff would appreciate the addition of a section of the IRP which specifically addresses the regulated emissions forecast that is expected to be required if Oregon House Bill 2020, as currently drafted, is enacted in 2019 and Oregon begins a Cap and Trade program. If HB 2020 passes in 2019, per Section 20 of the bill, forecast regulated emissions through 2030 will likely be based on the 2019 IRP, as the most recent IRP to be acknowledged as of January 1, 2021.

 Staff recommends PGE prepare an IRP section introducing the topic, along with clear graphs for regulated emissions forecasts under various portfolios.

# **Boardman Biomass**

Staff is interested in learning more about the reasons PGE has decided Boardman Biomass is not an economic option.

- If the company has performed quantitative analysis on the costs of this project in comparison to other capacity options, Staff requests PGE mention that analysis in the IRP and provide a copy of the analysis to Staff.
- Staff is also interested in a discussion of the economics of mothballing Boardman in case it can be used as a capacity resource in the near future.

# Energy Efficiency (EE)

On initial review of demand-side resources in the 2019 IRP, Staff notes significant interdependence across demand-side assumptions across scenarios. These inputs involve a number of discrete studies that assess the impacts of different demand-side resources. Staff is interested in understanding the assumptions that underlie the different studies, the assumptions across scenarios, and the interaction between different inputs into the studies. To give two examples:

- The draft IRP looks at a high EE scenario, which includes a 'low need' future with a simplified cost estimate of 125 percent of the cost of cost-effective measures.
- In both the regular and low need futures, PGE assumes EE costs will increase and less EE will be acquired over time.

Staff will be interested in further discussion of the reasoning for these assumptions.

Staff noticed a small typo on page 71, which references AR 622, which should be AR 621.

# Request for Proposals (RFP) Discussion

With Order No. 18-324, the Commission adopted competitive bidding rules (CBRs) for electric companies, now set forth in Oregon Administrative Rules Division 860, Chapter 89, instead of the past use of Commission guidelines. Under OAR 860-089-0250(2), additional RFP

<sup>&</sup>lt;sup>1</sup> PGE 2019 Draft Integrated Resource Plan. Page 168.

information must be included in a utility IRP unless the Company intends to develop and seek approval of a different proposal.

The CBRs require that the design, scoring methodologies, and associated modelling process used in the RFP be consistent with those from the IRP. Where they are not, the utility is required to file an alternative proposal for scoring and modelling prior to the filing of the RFP and support the change from the IRP.

PGE's IRP as drafted does not provide the requested information. For example, there is less information on the non-price scoring in the IRP than what has been provided in PGE's past RFPs. PGE does not include any threshold requirements that bidders will be required to meet in the planned solicitation.

In past solicitations, PGE has required bidders to have a plan to acquire firm transmission to deliver energy to PGE's territory. Appendix N does not list this as a requirement. In fact, it discusses adjustments to costs due to delivery requirements (see Delivery Point discussion below), seeming to imply PGE will make arrangements for delivery of off-system power.

"Delivery Point – Applicable transmission service costs will be applied in order to capture the incremental cost of delivering energy to PGE. These costs include wheeling, losses, and required ancillary services as prescribed in applicable tariffs, as well as any incremental costs for transmission or distribution system improvements necessary to deliver the energy to PGE.

However, for bids where the bidder has secured and is paying for transmission and ancillary services for delivery from the generation facility to an acceptable delivery point and the offer is inclusive of all applicable service costs identified above, no other transmission costs for those point-to-point services will be applied."<sup>2</sup>

Bidders would likely applaud that approach, if it is what PGE is planning. If, however, PGE is planning to require bidders bring transmission with their bids they should state as much in Appendix N. This will inform bidders, consistent with the requirements of the CBR and in line with what the Commission anticipated when it adopted the CBRs in Order No. 18-324.

In short, without major changes to Appendix N, the Company should plan on filing 'a proposal for scoring and any associated modeling' in a separate docket as called for in OAR 860-089-0250 (2)(a):

"(2) The draft RFP must reflect any RFP elements, scoring methodology, and associated modeling described in the Commission-acknowledged IRP. The electric company's draft RFP must reference and adhere to the specific section of the IRP in which RFP design and scoring is described.

(a) Unless the electric company intends to use an RFP whose design, scoring methodology, and associated modeling process were included as part of the Commission-acknowledged IRP, the electric company must, prior to preparing a draft RFP, develop and file for approval in the electric company's IE selection docket, a proposal for scoring and any associated modeling.

<sup>&</sup>lt;sup>2</sup> Appendix N. Page 486.

(b) In preparing its proposal, the electric company must consider resource diversity (e.g. with respect to technology, fuel type, resource size, and resource duration)."

# Transmission

Staff has reviewed the comments of National Grid regarding transmission in the PGE portfolio and is interested in further discussion of whether transmission modeling in the 2019 IRP allows for consideration of all resources on a fair basis.

- On page 121, Staff requests that PGE clarify whether the reference to ATC is under peak or non-peak conditions.
- On page 122, Staff requests that PGE define what it means by "constrained." Is this during peak?

Another concern for Staff is that PGE did not seem to consider conditional firm transmission in its IRP analysis.

 Staff is interested in the potential role of the conditional firm transmission product in PGE's system, and requests PGE confirm whether the 2019 IRP analysis considers conditional firm transmission.

### **Environmental Considerations**

PGE has modeled a linked carbon pricing program between California, Oregon, and Washington, using the CEC's allowance price forecast.

 Staff would like some discussion around whether it would be reasonable in the future to model PGE's dispatch based on a forecast of Oregon's Cap and Trade program, because the Oregon program is expected to have different targets than California's program, and may not be linked to California's program for some time. (See, e.g. House Bill 2020, wherein Oregon's plan is to reduce emissions 80 percent below 1990 levels by 2050, while California's plan is to get to 40 percent below 1990 emissions levels by 2030.)

### **RPS Need**

PGE explains that it is pursuing 100% physical RPS compliance because of customer preferences, Oregon's carbon goals, and PGE's carbon goals.

- Staff has some reservations about pursuing 100% physical RPS compliance based on goals other than planning for the best balance of least cost and least risk for customers.
- Staff requests more information on the average number of RECs PGE receives from QFs in a year, and whether this has been included in RPS planning.
- Staff is concerned about the proposed IRP Renewable Action Item given the lack of discussion and analysis involving PGE's REC bank and RPS sufficiency in the draft 2019 IRP. Per previous filings, PGE's proposed addition of 100 aMW of renewables in

LC 66, when combined with PGE's 2018 REC bank, would be sufficient under a zero load growth scenario to meet all of the Company's RPS needs through 2036.<sup>3 4</sup>

# **Voluntary Green Energy and Customer Preferences**

The large commercial Green Energy Affinity Rider (GEAR) was introduced in April 2018. PGE explains that the GEAR is a subscription model where customers are directly assigned the costs and output of a renewable resource that PGE contracts with via PPA.

• Staff requests PGE share the number of customers, if any, that have already signed up for the GEAR, along with the total MWa of these customers.

In Section 2.1.2 Customer Preferences – PGE discusses a survey that helped "inform its 2019 IRP portfolio construction, scoring metrics, and Action Plan." Staff has some concerns about relying in part on the results of a survey for the outcome of the 2019 IRP.

- Staff appreciates PGE's consideration of customer preferences. However, Staff has some reservations about using the results of a customer preference survey for long-term planning and how this practice reflects the IRP guidelines' requirement to plan for the best balance of least-cost and least-risk energy service.
- Staff will be interested to learn more about the survey methodology, and how accurately
  it was able to capture the preferences of PGE's customer base. For example, Staff
  would like to know if random sampling was used and if PGE considered whether using
  an online web survey could unintentionally exclude some customers from participating.

<sup>&</sup>lt;sup>3</sup> See LC 66 PGE Revised Addendum to the 2016 IRP, November 19, 2017, Figure 4, pg. 20

<sup>&</sup>lt;sup>4</sup> Additionally, the RFP for renewables emanating from the LC 66 actually acquired 150 aMW of renewables. Arguably, this 50% increase beyond the acknowledged action further impacts PGE's RPS sufficiency.

# Attachment A: 2019 IRP Stakeholder Comment Record

June 17, 2019

Organization: Renewable Northwest

IRP Topic(s) and/or agenda item(s): Comments on draft 2019 IRP

Comment:

Renewable Northwest thanks PGE for this opportunity to provide feedback on its draft 2019 IRP. We commend PGE for incorporating into this planning process several learnings from the 2016 IRP, and appreciate the Company's focus on meeting identified needs with renewable energy and other clean resources.

#### Flexibility value of renewables (including renewables plus storage)

Renewable Northwest appreciates the Company's receptiveness to including solar plus storage as a resource option. However, we remain concerned about the Company's decision not to assign a flexibility value to solar plus storage. We again encourage the Company to estimate and assign a flexibility value to solar plus storage in its 2019 IRP.

We also remain concerned about PGE's decision not to assign a flexibility value to renewable energy resources. The flexibility value in PGE's IRP "encompasses multiple operational value streams, including load following, regulation, spin, non-spin, and renewable integration (including both ramping and forecast error mitigation)." Renewables are capable of providing some of those value streams and therefore their flexibility value should be estimated.<sup>[1]</sup>

PGE's Appendix N identifies "flexibility benefits" as one of the criteria that PGE would use for scoring qualified bids in a 2020 Renewables RFP. It is unclear to us whether PGE would use ROM to approximate bid-specific flexibility benefits. We encourage PGE to clarify this and again encourage the Company to estimate and assign a flexibility value for stand-alone renewables and renewables plus storage.

#### Solar integration costs

Renewable Northwest remains concerned about PGE's high draft solar integration costs and about whether the Company's approach accurately captures the variability of solar resources. The draft 2019 IRP identifies a \$1.36/MWh solar integration cost. While this figure represents an improvement from the \$1.51/MWh that PGE presented to stakeholders on February 27, 2019, it is unclear to us whether PGE has addressed our concerns with its approach to modeling the variability of the solar.

Our understanding, from our February 1, 2019 meeting with PGE IRP Staff, was that PGE used linear scaling based off a single solar resource data point to forecast the generation profile of the future solar projects the Company is likely to integrate. At that meeting and in our May comments, we outlined our concern that such an approach is likely to systematically overstate the variability of larger single solar plants and would fail to capture the variability of a more diverse buildout of the solar resources that PGE is likely to need to integrate. We also suggested that PGE collect a broader data set by, for example, relying in University of Oregon solar insolation data. It is unclear to us whether PGE updated its approach. We question the accuracy of this solar integration figure if PGE continued to rely on linear scaling of a single solar resource data point.

### Treatment of transmission in IRPs and RFPs





# **WHITE PAPER**

# Comparing the Costs of Long Duration Energy Storage Technologies

Commissioned by National Grid Ventures

Published 2Q 2019

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# Section 1 INTRODUCTION

This white paper is the second in a three-part series exploring long duration energy storage technologies for the power grid. The first paper examined the factors driving the need for long duration energy storage and the role it plays on the grid. In this second paper, the installation and operating costs of the five competing long duration energy storage technologies are explored in greater detail. The third and final paper in the series will discuss other non-monetary factors that should be considered when evaluating energy storage technologies.

#### 1.1 Utility-Scale Long Duration Energy Storage Technologies

The utility-scale energy storage market encompasses a range of technologies with differing operating characteristics, strengths, and weaknesses. Some technologies are best suited to provide short-duration grid stability services including frequency regulation and voltage support. Such technologies include flywheels, ultracapacitors, and certain lithium ion (Li-ion) chemistries. Other technologies like pumped hydro storage (PHS) or compressed air energy storage (CAES) systems are best designed for large-scale long duration bulk energy storage. The following sections introduce the five most prevalent technologies competing in the long duration energy storage market.

### 1.1.1 Pumped Hydro Storage

PHS has traditionally been the technology of choice for delivering long duration storage services. It is the most mature and the largest capacity storage technology available, and currently provides approximately 93 percent of global operational electricity storage capacity. PHS facilities pump water from one reservoir into another at a higher elevation, typically using lower priced off-peak or surplus renewable electricity. When energy is required, the water in the higher elevation reservoir is released and runs through hydraulic turbines that generate electricity.

A key feature of any energy storage system is its **discharge duration**, which refers to the ratio between the system's maximum power output capacity in megawatts and its stored energy capacity in megawatt-hours.

PHS plants typically have a round-trip efficiency of 75-80 percent.

PHS technology has evolved over the years. Variable speed pumps represent the latest generation of the technology and provide significant advantages. A variable speed pump turbine can be regulated to plus or minus 20 percent of capacity during a pumping cycle, which provides the ability to accurately follow changes in both load and the supply of fluctuating renewable generation. In addition, variable speed PHS facilities can be designed to transition rapidly between pumping and generating. This flexibility, combined



with large storage capacity, means that PHS facilities offer grid operators capabilities that are critical to managing high penetrations of renewables and aligning variable renewable energy supply with shifts in load.

#### 1.1.2 Compressed Air Energy Storage

CAES systems compress ambient air, store it under high pressure conditions, and then release it to power generator-tied turbines when electricity is needed. The largest barrier to CAES development arises from geographical restrictions because the systems require either natural underground caverns or underground tanks, which are rarely in convenient locations. CAES systems are advantageous for the purposes of large-scale storage because they typically range from 50 MW to 300 MW of power output and can be brought to full output in around 10 minutes. However, CAES systems have relatively low round-trip efficiencies, ranging from only 48 percent for older designs to as high as 75 percent for more modern systems. There are only two large-scale CAES plants in operation—one in the US state of Alabama and one in Germany, with durations of 26 and 4 hours, respectively.

#### 1.1.3 Flow Batteries

Flow batteries are single-celled batteries that transform the electron flow from activated electrolyte into electric current. They achieve charge and discharge by pumping a liquid anolyte and catholyte across a membrane. While there are many different flow battery chemistries, the vanadium redox chemistry has emerged as the market's leading technology. The round-trip efficiency for flow batteries ranges from 65–85 percent.

Flow batteries have several inherent advantages over other battery technologies. Their discharge duration is correlated to the volume of electrolytes stored, so storage can be increased simply by adding additional tanks of electrolyte, **Round trip efficiency** refers to the difference between the amount of energy that is stored, and the amount of energy available for discharge. If a battery is charged with 100 kWh, but provides 75 kWh of energy when discharged, it has a round trip efficiency of 75 percent.<sup>1</sup>

with limited marginal costs. The technology is also generally safer than Li-ion or molten salt batteries—the use of nonflammable electrolytes means that most flow battery systems do not present a fire safety hazard. However, the electrolytes used in most flow batteries are corrosive and may be an environmental hazard if spilled. Furthermore, flow batteries experience little to no depletion of active materials over time, giving them greater cycle life expectancies (10,000+ cycles) than other battery types.

<sup>&</sup>lt;sup>1</sup> Hennessy, Tim, "Calculating the True Cost of Energy Storage," *Renewable Energy World*, January 12, 2015.



#### 1.1.4 Molten Salt Batteries

Molten salt batteries include sodium sulfur (NaS) and sodium-metal halide (NaMx) systems, both of which use a molten sodium anode and a solid beta-alumina electrolyte at high operating temperatures of about 300°C or more. Typical performance characteristics of NaS and NaMx batteries are relatively similar with regard to high energy density, long cycle life, and moderate-to-high round-trip efficiencies of 75–90 percent.

Molten salt batteries gained traction in the market early on, but the battery storage market has shifted heavily toward Li-ion technologies. This is because molten salt batteries' performance characteristics and high price point (which is driven by expensive betaalumina membranes) make them better suited for long duration applications, while the energy storage industry has recently focused largely on short-duration applications.

#### 1.1.5 Lithium Ion Batteries

Li-ion batteries use the flow of lithium ions between the cathode and anode of the battery to charge and discharge. Li-ion batteries have excelled as the primary chemistry of choice in consumer electronics for the last decade, and are now finding a limited role on the grid.

In general, Li-ion batteries have excellent energy and power densities and round-trip efficiency. However, as discussed in Section 2, their average duration of 4 hours limits their ability to support the integration of high percentages of renewable energy. A more thorough exploration of this issue is presented in the first white paper in this series, *What Is Driving Demand for Long Duration Energy Storage*?<sup>2</sup>

The relatively short cycle life of Li-ion batteries, which can range from 500 to 10,000 cycles depending on usage and the specific Li-ion chemistry that is used, translates into a 3–15-year lifespan. This makes Li-ion batteries an expensive choice for long-term grid applications. In the context of energy storage systems, one sequence of charging and discharging is referred to as a **cycle**. A system's **cycle life** refers to the number of times it can cycle or be charged and discharged before it degrades and becomes inoperable or unusable for a given application.

<sup>&</sup>lt;sup>2</sup> Navigant Research and National Grid Ventures, *What Is Driving Demand for Long Duration Energy Storage*? SL Energy Storage, 2Q 2019, <u>https://www.slenergystorage.com/resources.html</u>.



# Section 2

# LONG DURATION ENERGY STORAGE TECHNOLOGIES: FACTORS TO CONSIDER WHEN EVALUATING COSTS

#### 2.1 Comparing Apples to Oranges: Varying Characteristics and Costs

The five major long duration energy storage technologies discussed in this paper differ widely in terms of their operational benefits, cost structure, typical project scale, and development timelines. This section provides an overview of key points of comparison.

#### 2.1.1 Discharge Duration

Discharge duration refers to the length of time an energy storage system can discharge at full output capacity. While all five major long duration energy storage technologies are capable of long duration discharge, they vary considerably in their range of duration. Table 2-1 lists the average discharge duration for each of these technologies.

# Table 2-1.Average Discharge Duration Assumptions, Long Duration Energy Storage<br/>Technologies

Technology	Average Duration
CAES	3–24 hours
Flow Battery	2–12 hours
Lithium Ion Battery	0.5–8 hours
Molten Salt Battery	6–7 hours
Pumped Hydro Storage	6–24 hours

(Source: Navigant Research)

Although Li-ion battery projects can be designed to have a duration of up to 8 hours, most operational Li-ion batteries have durations of 4 hours or less. This places them at the low end of the duration range and limits their ability to offer a full suite of grid services. At the other end of the spectrum, PHS projects have average durations that range from 6 to 24 hours, with some plants designed to discharge at full power for longer than 24 hours. This duration enables them to replicate the grid and reliability services provided by conventional power plants.

#### 2.1.2 Project Scale and Development Timelines

Long duration energy storage technologies can vary greatly in their scale and development timelines, with corresponding impacts on upfront costs. While battery projects can be deployed more quickly at a lower initial cost they are often smaller in scale, averaging 5–50 MW in capacity. In contrast, PHS and CAES facilities are typically large-scale plants that provide 100 MW of capacity or more, requiring significant upfront investment and longer lead times.

The scaling of duration and total project cost also varies considerably between technologies. For Li-ion battery projects, scaling to longer durations requires adding more



battery packs, which represent the largest cost component of the project. Increasing duration results in an essentially linear increase in costs. By comparison, larger scale technologies such as PHS have different cost structures. Much of the cost to build a PHS project is fixed, coming from land development and construction. Scaling a PHS plant to longer durations requires only increasing the volume of the reservoirs being used, which has a relatively small impact on total system cost relatively to construction and development expenses.

#### 2.1.3 Upfront Installed Costs versus Lifetime Costs

Long duration energy storage technologies have a wide range of installed costs, which are typically noted in dollars per kilowatt-hour of stored energy capacity. Navigant Research expects total upfront installed cost for each of the major technologies to range from \$170.3/kWh for PHS to \$619.7/kWh for molten salt batteries, as illustrated by Chart 2-1.

Chart 2-1. Average Utility-Scale Bulk Energy Storage System Installed Cost (CAPEX) by Battery Technology, World Markets: 2019-2028



The falling upfront costs of Li-ion batteries have made them attractive for some grid applications, but they have a short lifespan compared to conventional generation assets and PHS facilities, which are typically designed to last for several decades. The average lifespan of a Li-ion battery storage system ranges from 3–15 years depending on how it is used and how the specific Li-ion chemistry employed. While the inevitable degradation of Li-ion systems can be addressed by replacing depleted battery modules over time, this practice increases lifetime project costs considerably. These and other considerations are explored in Section 3.



# Section 3 ACCURATELY COMPARING THE COST OF ENERGY STORAGE TECHNOLOGIES

#### 3.1 Comparing Apples to Apples: Levelized Cost of Storage

When evaluating energy storage technology options, it is critical that grid operators and regulators consider key pieces of the energy storage cost puzzle beyond upfront cost. A levelized cost of storage (LCOS) calculation can be used to more accurately evaluate the lifetime costs of different technologies and yield cost per megawatt-hour figures that support fair and valid comparisons.

Lazard has conducted extensive evaluations of energy storage technologies and applications. The advisory firm has developed a method for calculating LCOS that is perhaps the most robust comparison of the true cost to own and operate different storage technologies.

Lazard's LCOS calculation factors in the upfront investment required for a given storage technology. The calculation also incorporates operating patterns (cycles per day/year) for a given application, depth of discharge, round-trip efficiency, annual operations and maintenance costs, equipment replacement costs, system charging costs, and the overall useful life to yield an estimate for the cost per megawatt-hour, thereby enabling an apples-to-apples comparison.

Figure 3-1 illustrates the stark contrast in the LCOS for PHS and Li-ion batteries over similar time periods based on PHS project evaluation conducted by the San Diego County Water Authority.<sup>3</sup> PHS projects are designed for up to 50 years of operation with limited equipment replacement, a lifespan that can be extended to 100 years with proper maintenance and component replacements. By comparison, Li-ion battery projects typically have much shorter lifespans, although it is possible to keep them operating for 20 or even 40 years with proper maintenance and battery replacement.

<sup>&</sup>lt;sup>3</sup> Victor, David G, et al., *Pumped Energy Storage: Vital to California's Renewable Energy Future*. San Diego County Water Authority, 2019, *Pumped Energy Storage: Vital to California's Renewable Energy Future*, www.sdcwa.org/sites/default/files/White Paper - Pumped Energy Storage V.16.pdf.



As shown, these differences in operating life result in significantly higher levelized costs for Li-ion batteries. Using projected costs for facilities with a commercial operation date of January 1, 2026, over a 40-year operating life, PHS facilities have an LCOS of \$186/MWh, compared to \$285/MWh for Li-ion battery facilities for the same period.





(Source: Lazard and San Diego County Water Authority)



# Section 4 CONCLUSION

This report highlights several factors that can affect the true cost of different long duration energy storage technologies. In addition to the upfront costs to build a new project, the required operating costs and expected lifespan of each storage technology must also be considered.

While the falling upfront costs of Li-ion battery storage systems have attracted a lot of attention and increased the competitiveness of small to midsized battery projects, a more holistic view of total project costs shows that PHS and CAES deliver much better economics for ratepayers.

This white paper expands on the topic of long duration energy storage introduced in the first paper in this series. In addition to the financial considerations for each long duration technology presented in this report, there are many non-financial issues surrounding these technologies that must be considered when comparing technologies. These issues, including the safety, sustainability, and long-term reliability of battery energy storage technologies, will be explored in the third white paper in the series.



# Section 5 ACRONYM AND ABBREVIATION LIST

CAES	Compressed Air Energy Storage
kWh	Kilowatt-hour
LCOS	Levelized Cost of Storage
Li-ion	Lithium Ion Battery
MW	Megawatt
MWh	Megawatt-hour
NaMx	Sodium-Metal Halide Battery
NaS	Sodium Sulfur Battery
PHS	Pumped Hydro Storage
US	United States



# Section 6 SCOPE OF STUDY

This white paper examines the market for long duration energy storage technologies on the power grid. Specific attention is paid to the differences among technologies in terms of operational characteristics, lifetime, and project cost. Navigant Research prepared this white paper to provide an independent analysis of the opportunities for long duration energy storage. This white paper does not consist of any endorsement of any specific technology, project, or company. Rather, this paper provides readers with an understanding of technologies competing in the market for long duration storage and how they compare to one another.



Published 2Q 2019

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Note: Editing of this report was closed on June 26, 2019.

# Attachment A: 2019 IRP Stakeholder Comment Record

Renewable Northwest appreciates PGE's acknowledgement of the need to "reassess [] how it considers transmission within resource planning and procurement processes" as well as PGE's consideration of long-term and interim approaches to addressing the transmission landscape in which the Company operates. We look forward to collaborating with PGE on this issue.

We are generally supportive of the principles that the company outlined for an interim approach and look forward to learning more about the Company's thinking in the filed 2019 IRP. As PGE finalizes the details of its interim approach, we again encourage the Company to allow subsequent renewables-RFP bids to rely on conditional-firm transmission products. We also reiterate our recommendation that the Company considers BPA's TSEP timelines as it designs any future RFPs.

Finally, as the Company works on its long-term approach, we encourage the Company to commit to thoroughly examining how the IRP must adapt its transmission assumptions given regional transmission constraints and the scarcity of long-term firm transmission rights over BPA's system. We point back to the suggested approaches to future IRPs included in our May comments.

#### Stakeholder comments

Renewable Northwest appreciates the multiple opportunities for stakeholder feedback that PGE provided in this IRP. We encourage the utility to continue to improve on its stakeholder process by responding to the various issues raised by stakeholders in a monitored and timely manner.

June 30, 2019

Organization: None

IRP Topic(s) and/or agenda item(s): Grid reliability

Comment:

The issue of grid reliability when using high levels of wind and solar generation has not been adequately investigated.

The IRP needs to look at the worst-case weather scenarios experienced in Oregon and the Pacific Northwest over the past 50 years and verify that a generation mix containing large amounts of wind and solar would be adequate to the task of satisfying electricity demand under these worst-case scenarios. Analyzing typical or 'moderately worst-case' scenarios is insufficient.

#### July 15, 2019

Organization: National Grid and Rye Development

IRP Topic(s) and/or agenda item(s): White Paper on Comparative Costs of Long-Duration Storage

Comment: As a follow-up to the comments submitted on behalf of National Grid and Rye on June 7th, attached is a white paper just published by Navigant Research comparing the costs of various long-duration energy storage technologies.

In particular, the attached report highlights several factors that can affect the true cost of different long duration energy storage technologies. In addition to the upfront costs to build a new project, the required operating costs and expected lifespan of each storage technology must also be considered. While the falling upfront costs of Li-ion battery storage systems have attracted a lot of attention and

# Attachment A: 2019 IRP Stakeholder Comment Record

increased the competitiveness of small to midsized battery projects, a more holistic view of total project costs shows that pumped hydro storage delivers much better economics for ratepayers.