STAKEHOLDER FEEDBACK: January 2023

Received	*Stakeholder*	*Question/Comment/Response*
12/16/2022	IRP Meeting	Thank you for attending our December roundtable meeting. We had noted some questions from you that we were not able to answer during the meeting and I have included our responses below. Please let me know if there is anything else I can do for you. Our next roundtable is January 26 at 8:30am. You can find past meeting information and recordings here: https://portlandgeneral.com/about/who-we-are/resource-planning/integrated-resource-planning Is there any EE coming from just the utility and not through Energy Trust now? (slides 65-69)
1/6/2023	IRP response	Since 2002, Energy Trust delivers energy efficiency programs on behalf of Portland General Electric. PGE supports the Energy Trust both directly through funding but also indirectly through support such as combining energy efficiency and demand response efforts, customer engagement, and marketing efforts. PGE has not developed or deployed energy efficiency focused programs since 2002. Related, does the IRP include the specialize projects that do not fit into other established categories? For energy efficiency, Energy Trust does account for some larger and more specialized projects when providing near term estimates. Given the nature of these projects – they can only be certain in the near term and speculative in long-term planning – they are not a driver of the energy efficiency forecast.
12/16/2022	IRP Meeting	I see zero solar in any of the three portfolios on slide 66. Or perhaps there are near zero hybrid resources but substantial solar (yellow) resources?
1/6/2023		The non-cost-effective EE and DR portfolios on slide 66 from the December roundtable do not have any standalone solar. However, all of them include about between 300-500MW of solar + storage hybrids. This result highlights that the model is prioritizing capacity needs in these portfolios and meeting that need with hybrids. The wind resources were likely selected because they provide a reasonable amount of capacity in addition to energy, making them more competitive. A part of this behavior can able be attributed to the additional EE, which also provides both capacity and energy.

	IRP Meeting	Can you please elaborate on the timing of the transmission proxy build? It appears you are assuming that it is available in 2026. however, transmission takes a decade or longer. You noted that BPA transmission would be a decade away. How can you assume transmission to Four Corners, Mead, or Wyoming can be available in 4 years? As a follow up, it would appear that the transmission proxy would need to be a project similar to PacifiCorp's Gateway projects in terms of size or scope. It took PacifiCorp approximately 12 or more years from inception to the first segment of Gateway West being completed. How will PGE be able to aggressively meet an assumption to have 400 MW available by 2026 and unconstrained by 2031, when it has not been in the transmission expansion business like PacifiCorp and has a significant challenge to scale up internally to proceed in this direction? Is even a 2031 unconstrained assumption realistic?
1/6/2023	IRP response	The modeling conducted so far is meant to directionally indicate the level of transmission needed to meet PGE's reliability needs. PGE will navigate how to acquire the identified transmission capacity if the IRP portfolio analysis indicates a long-term cost and risk benefit of doing so.
12/16/2022	IRP Meeting	Interested in more information about "other" on slide 15 emissions. What is the definition of social cost? Definition of CE EE and non-CE EE.
1/6/2023	IRP response	Interested in more information about "other" on slide 15 emissions. In the graph 'other' includes unspecified purchases, waste, wood, and landfill gas. Please see page 56 of our Form 10-K for a detailed breakout: SEC Filing | Portland General Electric Company What is the definition of social cost? The term social costs refer to a category of costs that are borne by the society at large and not any individual or entity. In the IRP modeling context, the PGE leverages the EPA and other federal agencies' definition of social cost of carbon (SC-CO2) to assess the climate impacts of CO2 emission changes and rulemakings1. The underlying assumption is that the social costs of GHG increase over time because future emissions are expected to produce larger incremental damages as physical and economic systems become more stressed in response to greater climatic changes, and because GDP is growing over time. The SC-CO2 are represented as a proportion of gross GDP. The IRP selected 2.5% as the discount rate in intergenerational discounting to represent the social cost of carbon. 1Link to the social cost of carbon: https://19january2017snapshot.epa.gov/climatechange/social-cost-carbon_.html

		Definition of CE EE and non-CE EE. Energy Trust screened their energy efficiency potential based on the avoided costs of the 2019 IRP to determine which resources were cost-effective (passed the screen) and which resources were non-cost-effective (did not pass the screen). They provided the cost-effective EE potential information in the 2023 IRP as an input that reduces load. This was shared during the need futures section in the July roundtable. This process of Energy Trust screening their energy efficiency potential and the IRP providing the avoided costs that make up the screen highlights a delay. To address this delay, PGE is screening the resources that were previously deemed non-cost-effective to see if they are competitive now. Consequently, we gain early insight into if Energy Trust's savings should increase or decrease with the next update to the avoided costs.
12/16/2022	IRP Meeting	How is PGE planning to track the transmission user inventory need across that last mile? In the first step will there be at least a tracking of it just so stakeholders are aware of just how much it's relying on that last mile?
1/6/2023	IRP response	We are not planning on including and/or reporting this information in the 2023 IRP and CEP, as it will depend on the specific transmission expansion options we are pursuing, whereas the transmission component of the IRP's portfolio analysis directionally highlights what opportunities transmission expansion options could provide. As we refine this new methodology we will consider whether it would be warranted to adjust the type of transmission information coming into and out of this analysis.
12/16/2022	IRP Meeting	How much of the resource build contains natural gas builds?
1/6/2023	IRP response	A graph showing more of our Aurora assumptions can be found in the November 2021 roundtable slides (link below). On a net basis, we see declining gas units in the West from 2022 to 2030, and again from 2030 to 2040. https://assets.ctfassets.net/416ywc1laqmd/1UeTCdvEqHlpH1MRPOGo85/45b03c61b37dfaba7e0a434c8a8cfb3d/IRP-Roundtable-November-21-8.pdf
12/16/2022	IRP Meeting	Interested in more information about assumptions during emissions topic (slide 20) - are volumes of renewables on slide 20 the projections of what we would need to replace emitting resources? Is there comparison to other renewable resources or assumptions about the infrastructure or alternatives, or more generally what kind of assumptions underly these projections?

1/6/2023		We buy our Aurora model buildout data from Wood Mackenzie, a consultancy. More information on the database and assumptions can be found in prior roundtable meetings: November 2021: https://assets.ctfassets.net/416ywc1laqmd/1UeTCdvEqHlpH1MRPOGo85/45b03c61b37dfaba7e0a434c8a8cfb3d/IRP-Roundtable-November-21-8.pdf May 2021: https://assets.ctfassets.net/416ywc1laqmd/CNMm5LJjd1EVRDUkfHauN/4f39030995783e132df0bbe94d7d5f30/IRP_Roundtable_May_21-3.pdf February 2021: https://assets.ctfassets.net/416ywc1laqmd/5fZx2C5US1n7iSasPRjU4x/b752f1a798fe5e39255129e760af70ee/irp-roundtable-21-1.pdf Many utilities/organizations also run Aurora and make Western Interconnection buildout assumptions. For example, the Power Council estimates around 150,00 MW of new resource will arrive in the West by 2030: https://nwcouncil.app.box.com/s/bp2p4s9d1b9ijum6hhcgf4w0kuirtez7
12/16/2022	IRP Meeting	Can you say a little bit more about what was included from the 2021 RFP? The clearwater project is one of the ones selected but we don't have the others so will it represent the final decisions? Curious about the transmission risk of delays for upgrades – does this align at all with the TSEP process? Are the really specific upgrade needs captured at all in the portfolios? Would be curious to see if there is a way to have that reflected.
1/6/2023	IRP response	Can you say a little bit more about what was included from the 2021 RFP? The clearwater project is one of the ones selected but we don't have the others so will it represent the final decisions? The RFP proxy in the model roughly targets 250 aMW of renewable energy and 388 MW of capacity. The Clearwater Wind project provides some of that energy and capacity. The remaining need is met by proxy battery and renewable resources and does not represent final decisions. Curious about the transmission risk of delays for upgrades – does this align at all with the TSEP process? Are the really specific upgrade needs captured at all in the portfolios? Would be curious to see if there is a way to have that reflected.

		Transmission availability is aligned with BPA's TSEP process, as the characterization of the existing transmission system is based on an evaluation of the information provided in previous TSEP's. Additionally, upgrades to BPA's transmission system are expected to be 10-15 years away and are excluded from this IRP due to their uncertainty. We do model proxy upgrades to PGE transmission as the South of Alston (SOA) upgrade to see that impact.
12/16/2022	John Ollis	Sorry to make you review something from a year ago. I was in the deep depths of finishing up the power plan, so apologies for not remembering all the assumptions here. What I now remember, now that you kindly reminded me, is that prices are more volatile as seen in the graph below. My concern is that the limitation on the maximum prices lowered the maximum prices often enough to make it appear on average that the cost is of a portfolio with net load uncertainty is lower than one without. Were the frequency of events in the net load uncertainty scenario that exceeded the maximum 250 $/MWh limit fairly high?
1/6/2023	IRP response	Thanks for your astute questions and hope you had a wonderful holiday season. First, I'll point out that the first picture you included illustrates the electricity price difference between the reference case future and future with scarcity premium. There is no $250 price cap to the scarcity premium futures, the price cap only applies to the Net Load Uncertainty futures. Uncertainty futures We created the uncertainty futures in an attempt to reflect the unquantifiable impact of climate change on load, win, and hydro patterns. To do this, we mimic the operational errors of wind generation forecast and dispatch commitment misalignment by imposing a +/-15% forecast error on wind nameplate capacity of all new and existing wind resources in OR, WA, ID, and MT randomly to an hour of each month. We originally set the model price cap to $1,000/MWh, which is analogous to the FERC soft cap, but observed that there were many instances of triggering the $1,000/MWh price cap (which you rightly pointed out). Since we are interested in seeing the frequency of commitment error, rather than the price differential, we decided to lower the price cap to $250, which reasonably reflect the prices during the year 2000 energy crisis. Scarcity premium We created the scarcity premium futures to reflect the real world bidding behavior when capacity is limited and that resources would not be dispatched unless the start-up cost is covered. So, we activated the Aurora logic that adds the start-up cost of the marginal resource to the simulated price. We chose to do so for the on-peak hours only.

		Social Cost (your question at Roundtable) PGE leverages the EPA and other federal agencies' definition of social cost of carbon (SC-CO2) to assess the climate impacts of CO2 emission changes and rulemakings. The underlying assumption is that the social costs of GHG increase over time because future emissions are expected to produce larger incremental damages as physical and economic systems become more stressed in response to greater climatic changes, and because GDP is growing over time. The SC-CO2 are represented as a proportion of gross GDP. The IRP selected 2.5% as the discount rate in intergenerational discounting to represent the social cost of carbon. I hope I've addressed your concerns, please let us know if you have follow ups, happy to discuss more.
12/16/2022	Craig Patterson	I'm not sure if it was you or another PGE employee who spoke about using 'experts' to help with your modeling process. So I'm curious, who are your experts? What are their track records and background? What makes for an 'expert'? And how do you vette them and their projections? Are there any consequences if they are wrong? Who's keeping score? I would suggest, there are NO experts as this is all new territory. I would also suggest you have a roundtable of 'experts' dialogue together and see who makes the most sense going forward. I think my over 45 years dealing with energy and energy conservation issues might qualify me as an 'expert' too. Happy holidays, Craig Patterson
1/6/2023	IRP response	Thank you for providing your comments on our IRP process. The question of who are considered to be "experts" is an interesting one. For IRP purposes, PGE considers our technical staff to be experts over their specific analytical fields – they have the education and experience to create and evaluate analytical data as well as operate and improve models. Our managers and directors are experts we rely on to navigate the energy industry in general. The information and approaches we present are vetted through these PGE experts and then provided to attendees of the public meetings to receive feedback. For some approaches PGE works with OPUC staff directly to elicit feedback. As to consequences and keeping score, you may find those questions are more appropriate to direct to the OPUC. The IRP is a tool used to create shared expectations between the company and the Commission regarding future energy actions. The Commission is responsible for examining the analysis, results, and proposals which PGE presents and determining if they are reasonable. We greatly value the input we receive from the experts who participate in our public process. The analysts often get ideas for

ways to look at our modeling, or presentation of results, during the roundtable meetings. Specific requests for looking at information from different angles or performing modeling adjustments are helpful. We do not, however, take direction from the public on ways we must perform modeling. We are happy to take your comments at upcoming meeting and encourage you to put your thoughts into writing if you are interested in making detailed suggestions.

Our next public meeting will be January 26 at 8:30am, hosted on Zoom. Meeting agenda and participation links will be available as we get closer to the date.

We will share your questions and our answers in the next online stakeholder feedback pdf, posted in February – IRP Team