Integrated Resource Planning

PGE

STAKEHOLDER FEEDBACK: August 2024

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> *General Comments*
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> *Staff appreciates PGE's work to shift its modeling to an hourly model as discussed in LC 80. The information presented in these slides provides significantly more detail on clean energy surplus calculations. Staff looks forward to additional data on this in the IRP/CEP Update.*
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> *Staff would appreciate seeing the slide deck and materials for upcoming IRP/CEP Roundtables earlier. Receiving a large slide deck the afternoon before a meeting does not give Staff or stakeholders enough time to review and prepare questions and engage in meaningful dialogue as part of the roundtables. Staff suggests that PGE sends out the materials for the meeting no later than 48 hours before the roundtable.*

PGE understands and appreciates Staff's interest in seeing materials and results, and will continue to strive to post meeting slides with as long of a lead-time as possible. While PGE agrees that discussion would be better served when materials can be distributed earlier, the need to finish and/or refine results as well as conduct internal review may prevent PGE from meeting any timeline.[1]

> *Staff wants to remind PGE of its obligations from Order 24-096 for the upcoming IRP/CEP Update. Staff expects that anything discussed in that order that is required to be included in the IRP/CEP Update will be included in upcoming roundtables. These include:*

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[1] PGE has reviewed the procedures employed by our industry partners. Idaho Power typically shares materials within a week of stakeholder meetings but occasionally only provides partial materials. PAC is required to share materials three days before meetings but sometimes faces delays due to technical issues. The NW Power and Conservation Council aims to share materials a few days before meetings but sometimes is constrained by model run time dependencies.

- Staff Recommendations 3 and 5-8.

- The transmission study PGE agreed to conduct before the next IRP/CEP Update. Order No. 24-096 at 15.

- The short-term analysis of solutions to constraints that affect all resource delivery to PGE's load. Order No. 24-096 at 20.

- Any other issues discussed in the Order or comments that PGE is prepared to present on or plans to include in the IRP/CEP Update.

PGE thanks Staff for the reminder to follow Commission direction from Order 24-096 and the IRP guideline requirement to allow for significant public involvement in the preparation of the IRP. As described in the May 2024 Roundtable, the company intends to bring substantive discussions of each of these topics forward in upcoming roundtable meetings.

Brattle Study

1. Referring to slides 33-35, please confirm whether the hourly curves are averaged for the whole year or reflect seasonal or monthly variation. If they are averaged, how does PGE capture seasonal variation in the model? Lacking seasonal variation in this model will fail to fully capture the hourly premiums because the premiums will clearly change throughout the year. Staff suggests infusing data on seasonal variability and/or weather impacts on this data to ensure that the estimate of premiums at any given hour is as accurate as possible.

PGE clarifies that given the list of required and expected updates articulated in the May 2024 Roundtable the Company does not have the bandwidth to conduct this study of surplus non-emitting energy. Instead, the company has engaged Brattle to create this model to forecast results.

The clean energy surplus curves presented on slides 33-35 represent annual average values, on a monthly and hourly basis, of the total WECC-wide clean energy surplus, regional clean energy surpluses, deliverable WECC-wide clean energy surplus. The averaging is done on an annual basis to give a representative view of the Brattle analysis outcomes, and depict both monthly and seasonal variation in the graphs labeled "Mthly Average." The Brattle analysis produces an 8,760 time series of surpluses and premiums that captures seasonal variation in clean energy surplus. The clean energy surplus premiums represented on slide 35 likewise represents annual average values in each month or hour of day.

PGE also notes that the Company is following Commission direction to conduct its evaluation of its hourly energy position (and associated forecasts of emissions) under average expected conditions. PGE thanks Staff for the suggestion and is willing to work collaboratively on whether and how to prioritize the integration of weather variability and PGE's C-level analysis into non-reference-case forecasts of its energy position and resulting emissions.

2. After switching to an hourly premium calculation, has Brattle/PGE compared the hourly calculation to the annual calculation under the old method? If not, it would be helpful to see this comparison to understand how the new methodology compares to the old methodology, albeit with more granularity.

To clarify, there was no hourly clean-energy market methodology used in either PGE or Staff's hourly energy position analyses presented in the LC 80 docket. Rather, it was assumed in each analyses there was no non-emitting energy in any non-negatively priced hour.

> *3. Staff recommends further investigation of the value-based clean energy surplus allocation process and presentation on its outcomes in a future roundtable, as well as a comparison with the proportional method.*

PGE will evaluate the remaining topics yet to be discussed at future roundtables and will discuss with Brattle whether presenting at a future roundtable would be feasible.

> *4. What data did Brattle use to calculate the maximum premium? How often does the study predict that the maximum premium will occur?*

The Brattle analysis calculates the maximum premium using the levelized cost of energy (LCOE) for a new wind build, with scaling to account for potential uncertainties around development costs ("development cost scalar") and the amount of overbuild required to procure an equivalent amount of clean energy from a local clean energy resource ("availability scalar"). The LCOE represents the 2030 market value of the LCOE market value for a class 4 onshore wind turbine, as reported in the National Renewable Energy Laboratory's 2023 Annual Technology Baseline (ATB). The development cost scalar is based on input from PGE, and the availability scalar is based on average WECC-wide hourly wind productivity from the AURORA model database. Out of 8,760 hours in the year, the premium reaches its hourly maximum value in 291 hours, or roughly 3% of the time.

> *5. Please explain how transmission constraints factored into the deliverability limits and whether PGE has explored evaluating the data at a level of granularity smaller than the AURORA zones. The aggregate regional deliverability approach presented in slide 24 is too high level to capture all regional deliverability issues. Staff recommends calculating the estimated impacts of deliverability at the most granular level feasible.*

PGE has not explored different granularities of data evaluation; as noted above the timeframe and list of updates and new modeling components presented in the May 2024 Roundtable would not allow PGE's IRP team sufficient time to evaluate how different transmission constraints affect the deliverability of potential non-emitting surplus: accordingly, PGE engaged Brattle to help develop this methodology.

The deliverability limits used in the Brattle analysis are based on the inter-zonal transmission limits included in the PGE IRP 2030 Reference Scenario AURORA model. These deliverability limits are based on inter-zonal total transfer capability (TTC) constraints, adjusted for transmission utilization in the AURORA model results. The Brattle analysis did not explore evaluating the data at a level of granularity smaller than the AURORA zones. The regional approach presented in slide 24 reflects that the transmission availability between PGE and its immediate transmission neighbors will be the primary factor limiting deliverability of clean energy into PGE. It would be much more complicated, if not impossible, to determine the precise regional transmission capability in the rest of the WECC using the zonal-level AURORA model data. Therefore, both PGE and Brattle deemed it appropriate that the first iteration of this analysis uses the aggregate regional deliverability approach presented on slide 24.

6. Please explain why the study includes a capacity factor and whether there is any risk that any other variables, such as WECC-wide prices, are already reflecting capacity factors.

The study estimates the availability and cost premium of procuring clean energy from the market to help PGE evaluate its hourly clean energy position and the GHG reduction implications of its IRP portfolio potentials, with the potential benefit of helping to evaluating the economic tradeoffs of building local clean energy resources. The capacity factor is used to make the hourly clean energy premium more reflective of the costs of procuring an equivalent amount of clean energy from a local or contracted resource. Specifically, the hourly clean energy premium reflects the additional cost, beyond the energy transaction, of procuring 1 MWh of clean energy from the market. Instead of sourcing clean energy through hourly market transactions, PGE can opt to build or contract output from a wind generation facility, which has a variable hourly output and may require an overbuild to be capable of producing 1 MWh of clean energy in any given hour. As a simple example, if PGE were to procure 1 MWh of clean energy from a local wind resource in an hour when the wind capacity factor is 50%, then PGE would need 2 MW of wind capacity to produce the equivalent 1 MWh of clean energy.

7. What does Brattle define as "clean energy" for the purposes of this study?

The Brattle study treats non-emitting generation from onshore and offshore wind, solar, nuclear, and hydro resources as "clean energy."

8. How does PGE plan to model the market availability premium in its analysis? Does this modeling bring it closer to the 2030 1.62 MMT of CO2e target established in HB 2021?

The impact of the new clean premium model on total 2030 emissions compared to preliminary analyses described in PGE's LC 80 Round 1 comments depends on the timing of when the surplus non-emitting energy is available. If for example all of the surplus non-emitting energy is forecasted to be available in hours when PGE is long, then no, the available non-emitting energy will not help to address hours when PGE is short. On the other hand, non-emitting energy available in hours when PGE is short could reduce reliance on market purchases with associated carbon content (which was the default assumption in each of the LC 80 analyses conducted by PGE and Staff).

A premium associated with non-emitting energy refers to how much more expensive the non-emitting energy would be in each hour above the forecasted regular market price. For example, when solar is the marginal generating unit (and thus setting the market price), it follows that there will be no premium associated with surplus non-emitting energy. Conversely, if a coal unit was the marginal unit and many entities in the WECC were demanding non-emitting energy, that non-emitting energy premium would be high.

As discussed in the June 2024 Roundtable, there is an important financial question in hours in which PGE is short and there is non-emitting energy available, concerning whether it would be more cost-effective for PGE to purchase the energy in that hour or to build additional non-emitting energy. That financial characterization would require considering demand plus shifting hourly prices and availability of surplus non-emitting energy and the net costs and generation profiles of new builds. In other words, an hourly capacity expansion model. In the LC 80 docket Staff directly opined several times that PGE should not be investing the considerable time required to develop an hourly capacity expansion model. If Staff feels otherwise now, PGE would be willing to work with Staff on determining the prioritization of this modeling versus other competing work streams.

Currently PGE is developing its plans on using the availability of surplus non-emitting generation and the associated premiums into its analysis. OPUC direction for PGE to create this new method for the CEP/IRP Update was provided via Order 24-096 in April, and while the Company has devoted significant time and resources to answering the many questions posed, it has not yet determined the final method to be employed in the 2023 CEP/IRP Update.

> *9. PGE's 2023 IRP GHG modeling also assumed that PGE could sell renewables in the hours it was long. Is that still the case or can the Brattle Study inform new assumptions around curtailment? Staff's comments were that these are the hours when there is excess production in the region, hence PGE may not be able to sell. Staff sees this information as potentially a valuable way to address questions about PGE's ability to sell into the market and would like to understand whether this can be captured in the model.*

PGE has forecasted hourly prices throughout the entirety of the planning horizon and uses this market to justify the assumption that there will be a market for energy even when the Company is long. PGE does not believe the Brattle study would provide justification to modify this assumption. It could however demonstrate an elevated price for those sales (given the existence of the price premium), though this has not been the focus of our financial modeling and likely won't be in the near-term given the time requirements and complexity mentioned in the previous answer.

> *10. Referring to slide 14, please explain how the study interpolates the intermediate state clean energy targets and how that affects the model.*

The Brattle study interpolates state clean energy targets linearly between annual goals stated in each state's policy. Many state clean energy targets are given as step changes, but in reality, states are likely to gradually increase their clean energy generation to meet these targets. Some variation between states' clean energy development and the interpolated annual clean energy targets is likely (for example, due to banking of renewable energy certificates) and could produce small deviations in clean energy surplus and premium results. However, given that the non-interpolated state clean energy targets are legally-binding, we do not expect the magnitude of deviations to be substantial enough to alter the broad conclusions of the clean energy premium and surplus analysis.

11. Referring to slide 15, please describe what factors could shift the clean energy premium curve.

The WECC-wide clean energy production, state-level targets, and changing resource costs would likely shift the clean energy premium curve. Increasing clean energy production and state targets would change the surplus floor parameter used to define the clean energy premium curve because it is set by the minimum surplus when WECC-wide energy prices fall below a certain threshold ($0/MWh, in the Brattle study slides). Changing resource costs, including falling costs of new renewable capacity, would affect the max premium parameter used to define the clean energy premium curve.

12. What data does Brattle use to calculate state level surplus?

The Brattle study uses state-level clean energy production, state-level demand, and percent-based state-level clean energy targets to calculate state-level surplus. State-level clean energy production and demand are hourly outputs from the AURORA model. The percent-based clean energy targets are based on the 2023 Lawrence Berkeley National Laboratory (LBNL) U.S. State Renewables Portfolio & Clean Electricity Standards: 2023 Status Update. State-level annual demand is multiplied by state-level percent-based clean energy targets to calculate an annual state-level clean energy demand. Then, hourly state-level clean energy generation and load data are used to calculate surpluses in two steps. First, all hourly clean energy production in excess of the hourly load is counted toward the surplus (aggregated over the course of the year). Next, any remaining state-level clean energy in excess of the state-level clean energy target, aggregated on an annual basis, is counted as state-level surplus.

13. Referring to slide 38, how was clean energy surplus calculated for 2030 in the IRP Reference Case?

The Brattle study applied the calculation steps detailed on slide 19 to 2030 AURORA IRP modeling results to calculate the 2030 clean energy surplus.

14. Please explain whether the clean energy surplus is primarily production driven and the extent to which it accounts for seasonal variations in load, extreme weather conditions, increased AC usage, etc.

The clean energy surplus is driven by production, demand, and state-level clean energy policy targets. Clean energy production acts to increase clean energy surplus. Demand for clean energy, which is driven both by electricity demand and state-level clean energy policy targets, acts to decrease the clean energy surplus. The dependence on load means that clean energy surplus accounts for seasonal variations in load, the load impacts of extreme weather conditions, changing consumer behaviors, and other factors, to the extent they are reflected in the PGE IRP 2030 Reference Scenario AURORA model results.

15. Is there any additional data, such as examining RFPs/IRPs of other utilities, that *could be used to capture availability of surplus? How has Brattle verified that the use of state energy targets accurately accounts for availability of surplus?*

The Brattle study is based on the outputs of the AURORA modeling used in PGE's IRP analysis. Additional data, including RFPs and IRPs, could be included in the Brattle study framework to the extent that they could be included in PGE's AURORA modeling. The Brattle study is an accounting estimate of WECC-wide clean energy, rather than a re-optimization of WECC-wide clean energy dispatch. Therefore, the study framework is not set up to include additional data not already represented in the AURORA model. PGE notes that the Commission direction the Company received specifically stated that PGE use production cost modeling for this work stream, and the company is complying with that direction.

16. Referring to slide 26, does Brattle have support for the statement that "the demand for clean energy beyond state-mandated targets in the WECC has value dynamics similar to RECs in other markets?" Utilizing PJM data without adjusting for regional variation in deliverability and other components may lead to an inaccurate estimate. The three sREC Auction curves on slide 28 show different curve shapes (noting that the scale on each chart is different).

Both renewable energy certificates (RECs) and clean energy more broadly are valued and traded for their clean attributes. The Brattle study therefore assumed that buyers' willingness to pay to procure the clean attribute of clean energy (such as to meet state-level GHG emissions goals) would be similar to buyers' willingness to pay for the clean attribute of solar energy to meet mandated state-level targets, and that the sensitivity of demand to price would be similar in both types of markets. The Brattle study used PJM sREC auction outcomes because public data were not available on outcomes for clean energy attribute auctions in the WECC. To account for regional differences, the Brattle study normalized the PJM sREC auction outcome curves and scaled them using parameters derived from WECC market modeling. Results from a Brattle sensitivity study evaluating the impacts of the clean energy premium curve shape on clean energy surplus are included on slide 47. The Brattle study authors would welcome Staff input on further refining the curve shape parameter.

Comments on Capacity Need

1. Referring to the shift of the study years forward, this will add in additional years with high load (from extreme heat events or other factors). How much do these outlier years influence the outcomes of the data? Does PGE plan on accounting or adjusting for these years?

PGE does not plan on adjusting new estimates of capacity need. The company believes the changes articulated in the August roundtable to be an improvement on the current methods and better represent future climate-load scenarios: the IRP team at PGE believes that if the input change is appropriate, the resulting resource adequacy estimates should also be appropriate. Slide 55 (and several subsequent slides showing the same information) details the magnitude of the estimated changes associated with the additional years.

2. What is the purpose of the bins? How does PGE use the bins to inform capacity need evaluation?

As described in the (May 2021 ppt. video, March 2022 ppt. video, and January 2023 ppt. video roundtables) and Section H.3.1 – Overview of the 2023 CEP/IRP, Sequoia uses a Monte Carlo analysis to evaluate the resource adequacy position in many hypothetical weeks (typically 50,000 but that varies depending on the task). That evaluation involves simulating the total demand with aggregated generation supply available. To each individual week PGE randomly assigns seven daily load profiles, and then assigns seven daily renewable generation supply profiles. To account for correlations in renewable generation and load, PGE uses five 'bins' of load intensity profiles. For example, a day that is evaluating a load profile in the 85th percentile of demand will be randomly assigned a renewable generation profile from the same month from a day that also saw load somewhere in the fifth bin (so load weeks in the 81th-100th percentile). Alternatively, without the use of load-renewable bins a very high-load day could be evaluated using renewable generation profiles from average conditions, which in the presence of load and generation correlations could present an inappropriately optimistic view of renewable generation.

3. Is PGE using multiple metrics for resource adequacy (other than 1 day in 10 years)?

Currently Sequoia estimates a seasonal capacity need based on an adequacy level of 24 hours in ten years (2.4 LOLH). While it is possible to estimate and report other adequacy metrics, it would take a significant investment to investigate whether it would be possible to estimate resource adequacy need applying two standards. If Staff and/or other stakeholders believe PGE should pursue this option, PGE is willing to consider how to prioritize this work over other modeling expectations.

4. Is PGE considering extreme weather events? How is it modeled?

The load of all hours in the years 1994-2023 are included in this analysis, and that dataset includes many hours considered to have extreme weather. They are modeled consistently with all other hours in the dataset.

5. Has PGE calculated the impact on prices when capacity reserves tighten under this new methodology? Please provide an analysis of the cost impacts of this scenario.

As discussed in the (May 2021 ppt. video and August 2022 ppt. video roundtables), there is no economics incorporated into PGE's resource adequacy model Sequoia. Accordingly, the new methodology has not prompted PGE to evaluate any price impacts caused by changing capacity reserves.

6. What is your overall hypothesis about the findings? Why does PGE think that capacity need is increasing in summer and decreasing in winter?

At the August Roundtable PGE discussed several drivers of the overall changes in draft seasonal capacity. A main difference was the different seasonal load shapes associated with the May 2023 and May 2024 load forecasts described on Slide 70: winter showed a decrease in the distribution in all hours, but summer morning and evening hours are significantly higher. PGE believes this is the largest driver in differences in capacity need, but there were others mentioned as well.

> *7. Referring to slide 72, please explain the significant decrease in QF MW modeling for PV East.*

OPUC Order No. 24-096 directed PGE to recalculate its IRP inputs using an assumption of 75 percent for QF renewals and the QF success rate for Schedule 202 projects. While Staff's recommendation that was adopted by the Commission was for avoided cost purposes, PGE believes that this direction should be carried forward in all IRP analysis as well (rather than having two sets of data for avoided costs and the IRP). The PV East resource in Sequoia represents all forecasted solar QF resources east of the cascades. In that group, the directed change in assumptions led to a 29 MW decrease in solar available in 2028.