

Integrated Resource Planning



STAKEHOLDER FEEDBACK: June 10, 2026

Received: June 10, 2026 during roundtable chat

Stakeholder: Alessandra de la Torre

Organization: NWECC

Applicable Public Meeting Date: Jun 10, 2026

- 1. The [Resiliency & Reliability Metric 5] data from like SAIDI, if that's also encompassing any outages that may happen because of enhanced safety settings on power lines during fire season?**

PGE Response:

SAIDI and SAIFI values for Resiliency & Reliability will be calculated from historical outage data, inclusive of outages on devices under the operating settings in place at the time of the outage.

If enhanced safety settings during wildfire season result in actual customer outages, those outages would be reflected in the historical reliability data used for SAIDI/SAIFI reporting. The metric is not based on simulated outage impacts or modeled projections of specific asset enhancements or operational settings. Over time, the reported reliability data can help indicate whether these operating practices are affecting reliability outcomes.



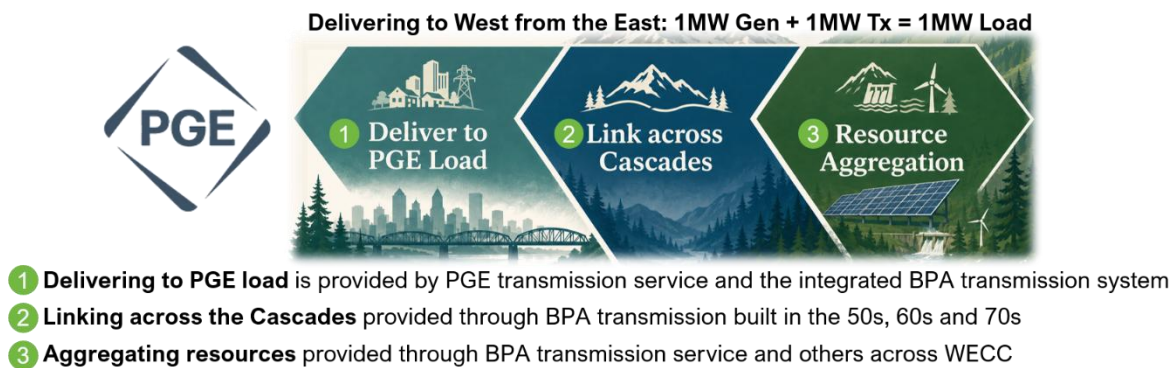
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Stakeholder: John Kopinski

Organization: NextEra Energy Transmission

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By way of context, we have been evaluating the required three-leg pathway from resource aggregation to PGE load, as outlined below.



Based on our review of the current PGE IRP/CEP transmission modeling, particularly as it relates to CRTP, we have the following questions.

2. Attributing CRTP with Summer and Winter Capacity Value: As we have reviewed the transmission alternatives available to PGE, we believe CRTP, when paired with the PDCI, other rights and expected BPA GERP buildout for Lower Columbia to NOB, would provide both winter and summer capacity value. In particular, there may be up to 25 GW of available redirects at Big Eddy. We have engaged EGPS, and this is one of their initial findings. It has also been confirmed through our internal modeling.

Questions: Will PGE be revising the modeling CRTP capacity value adjustment in your models? If not, what additional information can we provide to justify this revision?

PGE Response:

PGE's 2026 IRP modeling of CRTP does not include access to diverse market front office transaction. CRTP terminates near The Dalles, and does not reach the diverse markets of



California, Desert Southwest, or SPP/MISO. To access diverse market front office transactions, a project must be able to demonstrate physical access with long term firm rights to one of these three regions. Big Eddy Resource Access of 25GW for CRTP: In addition to the capacity value adjustment, the resource access options being aggregated at Big Eddy of up to potentially 25GW creates a very broad pool to be withdrawn from CRTP and delivered to PGE including California, Desert Southwest, and Mountain West.

3. Questions: Will PGE revise its modeling of CRTP resource access to include all regions that CRTP could reasonably access? If not, what additional information can we provide to justify this revision?

PGE Response:

PGE's 2026 IRP modeling of CRTP does not include access to the resource zones associated with California, Desert Southwest, and Mountain West. CRTP terminates near The Dalles, and does not reach the diverse resource zones. CRTP is able to access resources across BPA's network through assumed transmission requests or redirect requests. To diverse resource zones, a project must be able to demonstrate physical access with long term firm rights to one of these regions.

4. CRTP is Independent without contingent facilities: It does not appear that contingent facilities, such as North of Marion and North of Pearl, are being considered in the modeling when selecting the MW unlocked by transmission alternatives. Based on our prior discussions, we understand these facilities are assumed to be in service. For CRTP, this approach appears appropriate because CRTP provides a direct pathway to the heart of the PGE system and is not contingent on BPA or other projects. However, for some of the other projects being assessed, this approach may not fully account for which leg or legs are required to create a complete path from resources to PGE load. In addition, the modeling appears to apply a COD for each project individually, rather than considering the latest COD across the full three-leg path required for delivery from resources to PGE.

Questions: Will PGE adjust the CODs of available transmission alternatives based on the latest COD of their contingent facilities? Will PGE include a sensitivity to evaluate how BPA's allocation of only partial transmission rights to PGE, created by the GERP projects, could impact the value provided by PGE's transmission alternatives?

Finally, below is our high-level view of how the PGE transmission alternatives interrelate.



Project	COD	BPA Contingent Facilities ISD	1. Deliver to PGE Load	2. Link across Cascades	3. Resource Aggregation	Function
WSPP #1	2032	2035+	○	✓	●	Resource aggregation and Cascades transfer capability
NPC #1 / Colstrip Repurpose	2032	N/A	●	●	✓	Repurposed Colstrip delivery and Cascades transfer; Eastern Interco
Blueprint S	2032	2035+	○	○	✓	Resource aggregation from Mountain West and California
C RTP	2032	N/A	✓	✓	●	PGE load delivery, Cascades link, and Mountain West / California / De
PGE Trojan Harborton #3	2034	2035+	✓	○	○	I-5 Access / local PGE load delivery
WSPP #2	2035	2035+	○	✓	●	Resource aggregation and Cascades transfer capability
NPC #2	2035	2035+	○	○	✓	Resource aggregation from Eastern Interconnection and Mountain W
Greenlink	2035	2035+	○	○	✓	Desert Southwest resource aggregation
SWIP N + B2H	2036	2035+	○	○	✓	Desert Southwest and Mountain West resource aggregation
Gateway W + B2H	2036	2035+	○	○	✓	Mountain West and Desert Southwest resource aggregation

Contingent Facility	COD	BPA Contingent Facilities ISD	1. Deliver to PGE Load	2. Link across Cascades	3. Resource Aggregation	Function
Repurposed TSRs (e.g., Colstrip to PGE)	N/A	2030	✓	✓	✓	Repurposed delivery, Cascades transfer, and resource access rights
Garrison to Ashe	N/A	2035+	○	✓	○	BPA contingent Cascades link / redirect capability
NOM	N/A	2035+	✓	○	○	Delivery to I-5 Load
NOPE	N/A	2033	✓	○	○	Delivery to I-5 Load
BPA BEC	N/A	2033	○	✓	○	BEC

PGE Response:

PGE's 2026 IRP describes the contingent facilities associated with each transmission project including those listed on the attached table. The contingent facilities are included in the assumed COD dates of each project. The 2026 IRP does include sensitivities related to the unavailability of near term transmission projects that could be driven by the failure or delay of contingent facilities.

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Stakeholder: Pat DeLaquil

Organization: MCAT

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5. Lack of specificity on how rCBIs have changed since the 2023 IRP and its impacts on CBREs

In the 2023 CEP/IRP, PGE used a resource CBI for CBREs that applied a 10% cost reduction. (Slide 23) For the 2023 CEP/IRP update, PGE assumed that CBRE Solar “if qualified by providing tangible and resilience benefits to community is based on a 6.8 percent increase in property values, reflecting benefits tied to behind-the-meter installations for residential customers.” (2023 IRP Update at 125) In its May 20 IRP roundtable, PGE presented for 2026 regarding CBIs does not offer clarity on how PGE is looking at CBIs and their impact on CBREs in the context of PGE’s modeling (May 20 presentation, slide 15).

For example, PGE included a slide on rCBIs describing its CBRE RFO process with the following sentences: “incremental portfolio costs provide directional insight into procurement costs associated with pursuing targeted community benefit outcomes,” and “the cost delta provides a directional estimate of incremental procurement costs associated with pursuing resource strategies aligned with targeted community benefit outcomes.” While these statements seem to suggest that PGE plans to apply a negative rCBI to CBREs, compared to what it did in the 2023 IRP, the statements in that slide are unclear.

Is this what PGE is planning?

At this stage in the process, stakeholders should have a clear sense of how PGE plans to treat CBREs in its modeling so that we can have a real opportunity to engage and provide feedback where applicable. This is not what the May and June IRP meetings have afforded us on the topic of CBIs and their use in this current IRP/CEP process when it comes to CBREs. We are especially concerned in light of PGE’s plans to drastically reduce its 2023 IRP plan on CBREs.

Throughout its slides, PGE points to its engagement with the IRP roundtable and CBIAG on CBIs. PGE’s decision to dismantle the Learning Labs limited its engagement on this particular topic with another highly motivated and knowledgeable stakeholder community. PGE should strive to also include its newly launched Equity Policy Council in future conversations on CBREs and CBIs.

PGE Response:

PGE discussed the CBRE RFO results at the February 2026 Roundtable, and shared that this market data would inform the CBRE assumptions for the 2026 CEP/IRP as an incremental improvement compared to previous screening assumptions that were not based on actual market information.¹ PGE indicated at the May 2026 Roundtable how this information might also inform an analytical approach for rCBIs, though data review and precise methodologies were still in development at that time.² PGE will more clearly describe both the rCBI methodology and draft results for the 2026 CEP/IRP at the August 2026 Roundtable.

As communicated throughout planning cycles: data collection, methodology development, and analysis take time. The scope of analytical asks and needs also expands each time as PGE and stakeholders learn more and seek to dive deeper into ranging topics. The shift in IRP filing dates to annual requirements further compresses timelines for this development, stakeholder feedback, and iterative refinements. This is also why PGE has sought prompt feedback from stakeholders after each Roundtable in an effort to hear interests early and often to be able to best consider as analysis swiftly develops.

Thank you for your feedback regarding stakeholder and community engagements. PGE is regularly considering and evolving outreach approaches and groups engaged on planning and other topics and will consider this feedback when developing future activities.

Integrating pCBI scores into selection of the “least cost least risk” portfolio**6. Slide 24 states that pCBI (portfolio CBI) results are reported out but not used directly in any further quantitative-specific analysis to compare portfolios or for determining a “least cost least risk” portfolio.**

We urge PGE to give more thought to how the relative pCBI scores should be impacting the selection of the “least cost least risk” portfolio and to use pCBI scores in portfolio selection. At the very least, where portfolios are similarly situated from a cost and risk basis, CBIs should be a factor in the preferred portfolio selection.

1

https://assets.ctfassets.net/416ywc1laqmd/oh36t62jePnaYjHNBxl6/f6a66f2c61cad892f05b6eff5e1850f6/CEP_IRP_Roundtable_Feb_26-2.pdf#page=31.

2

https://assets.ctfassets.net/416ywc1laqmd/iOtlq68CuHUHy2e6d0Jv7/f822e4294d6c0035a1d75299a83bf491/CEP_IRP_Roundtable_May_20_-_4.pdf#page=8.



PGE Response:

Thank you for your feedback. In alignment with OPUC Order No. 22-390, pCBIs are reflected in IRP portfolio scoring. They are considered as 'non-traditional' metrics that help account for risks and considerations across scenarios in ways not captured with the traditional economic risk metrics. PGE does not have a prescribed data-based methodology for weighing or comparing across non-traditional metrics to quantitatively inform which scenarios are considered more least-cost, least-risk. The pCBI metrics are directionally helpful for understanding which portfolios are adding resources with potentially greater community benefit, but these metrics alone do not show the full picture of benefits nor costs and are therefore considered in conjunction with other modeling, results, and real-world emerging information to inform complex decision-making that ultimately must balance community interests with affordability, reliability, clean energy, and other key objectives.

7. Makeup of the Health and Community Wellbeing Metric

Currently, pCBI scores are based MWs of capacity installed in 5 categories: Economic Impacts (of in state resources), Energy Equity, Health & Community Wellbeing, Resilience & Reliability, and Environmental Impacts. On Slide 54, Equity and Health don't show well across any scenario. Why is that? Looking back to Slide 25 from the May 20 slide deck, clean resources that decrease outdoor air pollutants don't register on the Health and Community Wellbeing metric? Why is that? This appears to be why Health benefits of cleaner portfolios do not show more prominently.

PGE Response:

On Health & Community Wellbeing, while adding clean energy to the system can provide a range of benefits, it does not guarantee a decrease in outdoor air pollutants. This would only be the case if these non-emitting additions were proven to prevent the addition of emitting resources (or offset output from existing emitting resources), *and* that those emitting resources would be near enough to communities such that the community might be impacted by localized air pollution. Given the complexities of reflecting these types of concepts in modeling, PGE took a more conservative approach when assigning Health & Community Wellbeing pCBIs.

Similarly on Energy Equity, PGE opted for a more conservative approach in assigning pCBIs as any proxy utility-scale clean energy additions in the modeling are to support the system, i.e., all customers, and may or may not have more direct benefits for EJ or other



communities. This level of detail is difficult to reflect in long-range system-level modeling and would be more project-specific in nature, identifiable more through procurement processes than in proxy model assumptions or findings.

8. Current scenario options are based on a central station design model

Slide 38: The significant difference between the Reliability only and GHG Glidepath scenarios is that the new demand for Data Centers is being met using a traditional central station design model that focuses on central station resource, long-distance transmission, and inflexible loads. This is a high-cost approach that under-utilizes existing distribution assets and under-values the benefits of distributed resources that are closer to the load they serve. What ELCCs are used for the solar and wind standalone and hybrid technologies, and what is their basis? How strict is the fossil plant glidepath. How much of a difference would it make to allow the existing gas plants to exceed emission limits during peak load conditions? We recommend that a High Distributed Energy Resources (High DER) resource option be added that assumes utility rate-based investment in distribution system generation and storage systems managed to reduce peak loads and increase overall system utilization.

PGE Response:

Draft portfolio results from the July Roundtable suggest both the RO and GHG portfolios assume roughly equivalent quantities of VPP resources (slide 61 – July Roundtable). Slides 55 and 56 of the July roundtable also suggest the relative comparison of RO to GHG cumulative resource buildout is not significantly different for load forecasts including data center load against the Core Load Growth Only Scenario. Both load forecast scenarios lead to a 2030 RO resource buildout that is approximately 20% that of the GHG portfolio. ELCCs used for the solar and wind standalone and hybrid resources are discussed in the February Roundtable (ELCCs reflecting May '26 load forecast update discussed in July Roundtable). ELCCs for both supply side and demand side resources are estimated through an hourly stochastic loss of load probability (LOLP) study using Sequoia (see 2019 IRP Update Appendix K). The LOLP study simulates project level characteristics such as round-trip-efficiencies; interconnection, transmission and grid charging limits, using geographically specific generation shapes derived from the NREL SAM model. The emissions reductions of HB2021 represented in the glide path are a binding constraint. The relative effect of relaxing this constraint would be subject to the degree and frequency and is not modeled as part of the IRP. PGE appreciates the concept of a High DER scenario, and has modeled assumptions on available capacity and costs of DER resources with respect to best estimates of potential within the service territory.



9. VPP Potential is bound by Low Upper Limits

Slide 40: The VPP contribution to all scenarios appears quite limited, especially relative to the conclusions of the Brattle Group study which estimates that VPPs cost 40-60% less than other energy sources and widely deploying VPPs across the country could save up to \$35 billion for ratepayers by 2030 (Brattle). We recommend that the High Distributed Energy Resources (High DER) scenario be designed that better reflects the energy, ancillary services, emissions, T&D investment deferral and resilience benefits that DERs can provide. See the following excerpts from the Brattle1 report.

<https://www.brattle.com/insights-events/publications/real-reliability-the-value-of-virtual-power/>

PGE Response:

VPP is an important resource for PGE. Different types of customer-owned devices like EV chargers, smart thermostats, water heaters, and behind-the-meter generation and storage are coordinated or dispatched by PGE to reduce peak demand, support system reliability, and respond to grid emergencies. In addition to providing capacity and reliability benefits, these resources help lower customer energy costs, reduce expensive energy purchases, and support emissions reductions.

PGE's VPP portfolio orchestrates more than 600 MW of flexible capacity from over 230,000 participating customers, representing approximately 25 percent of PGE's customer base. Residential participation in PGE's VPP programs is approximately four times the national average. The VPP contributions shown on slide 40 presented just the additional cumulative capacity that is forecasted to be available in different bins by the end of 2030 following reference case of DER adoption. Those contributions did not include the VPP Flex Load capacities in MW that are already existing in the system. Bins 1 and 2 represent existing PGE programs, bin 3 includes other programs and pilots of smaller scale, and bins 4 and 5 include new DER measures that are emerging with some being cost-effective and others not due to many factors which include technology availability and cost, measure maturity and scale of deployment.

In the IRP analysis we have also included low, reference and high DER forecast scenarios but the slide only presented the reference case values to manage the volume of information being presented.



10. Annual Cost Comparison is missing the Cost of Climate Damages

Slide 43: There is a significant element missing from this Annual Cost Comparison, which is the impact of the climate damaging emission that each scenario produces. One solution to this would be to add a climate damages cost (using an appropriate Social Cost of Carbon²) to the model's annual cost results. Looking at the 2030 scenario emissions in Slide 38, the difference between the GHG Glidepath and Reliability only is 3 MMTCO₂e, which at \$185/Mt is \$555 Million in 2030 alone. The total number of annual MWh³ sold by PGE in 2025 is 22.53 million MWh, would give an annual cost of 24.6 \$/MWh, which compares to the 2030 difference of about \$20/MWh between the HB2021 Glidepath and the Reliability only scenario.

PGE Response:

The annual costs provided represent the generation and transmission costs that are modeled in the IRP. They are not inclusive of all system costs such as distribution, labor, PGE transmission, wildfire, O&M, and other costs included in total revenue requirement that are outside of the scope of IRP analysis.

A social cost of carbon represents one way to economically value climate damages. When evaluating portfolio costs for portfolio scoring purposes, which were further discussed at the August 2026 Roundtable, PGE evaluates metrics to assist in determining a least-cost, least-risk portfolio that complies with all state and federal laws. As a result, PGE evaluates costs associated with generation and transmission costs over the course of the planning horizon, alongside economic metrics that assist PGE in evaluating risk (such as variability and severity). PGE also evaluates emission impacts as calculated under ODEQ methodology, which is required by House Bill 2021.

Given PGE is already assessing the cost and emissions results for each portfolio under the methodology that is required by state law, we do not plan to incorporate a social cost of carbon or any additional emissions or climate change cost related metric(s).

Impact of Power Act on New Data Centers and HB 2021 implementation

Slide 47 shows how having No New Large Load Growth impacts the needed new capacity builds. In fact, these scenario results allow us to identify the components driving new capacity needs. In particular, the capacity difference between the GHG Glidepath and the GHG No NLL scenarios represents the amount of new capacity (7.3 GW = 15.3 GW - 8 GW) needed for the energy needs of new Data Centers and other large compute loads, which should be incorporated into their rates under the POWER Act. Likewise, the difference between the Reliability Only and the RO No NLL scenarios represents the new capacity needed for reliability needs of new Data Centers, which should also be incorporated into their rates under the POWER Act. The RO No NLL scenario itself represents the Reliability



needs of all other customers, while the capacity needed to meet the energy needs of non-Data Center loads is the remainder, which is the difference between the GHG No NLL and the Reliability Only scenarios, as shown on Slide 47. The most current, well-supported values for the Social Cost of Carbon (SCC) cluster around \$185-\$200 per metric ton of CO₂ in 2025-2026, depending on the model and assumptions. Here are the authoritative, up-to-date figures from the sources returned in search. (CoPilot) 3PGE's total electricity sales in 2025 were 22,530,000 MWh of retail energy. This figure comes directly from Portland General Electric's 2025 Form 10-K filing, which reports retail deliveries by customer class. Interestingly, the new capacity needs for reliability are split 2.1 GW for Data Centers and 3.0 GW for other customers, while the GHG component is split 7.3 GW for Data Centers and 2.9 GW for other customers. This makes sense that non-DC loads would have a greater impact than Data Centers on reliability, and a much smaller impact on GHG targets. As a result, the incremental new clean energy capacity needed to meet HB 2021 target is reduced from 5 GW to 4 GW in 2030 and 9.3 GW to 5.9 GW in 2035. This raises the question of why the Reliability NLL case shows such steep growth in 2030, which is probably due to the restricted use of gas starting in that year, and raised new questions:

- Would allowing existing gas plants flexibility to meet infrequent reliability concerns reduce the system capacity needs?
- How does requiring Data Centers to be non-firm loads change the system capacity needs?

This preliminary result highlights an important interaction of requirements under the POWER Act with implementation of HB 2021.

- The Power Act requires that new capacity builds and resource acquisitions for Data Centers be incorporated into the data center rates and not spread over other customers.
- Therefore, all data center costs should NOT be included in the HB 2021 cost cap calculation, because those costs are already allocated to the data center's rates under the POWER act, and the cost cap provision was intended to protect existing customers from excessive rate impacts.

PGE Response:

Reliability Needs - Allowing natural gas plants the flexibility to meet reliability needs does directly reduce the volume of resource additions needed to address system capacity needs. In fact, all scenarios modeled in the 2026 IRP assume that PGE's existing fleet of natural gas plants are available to meet reliability needs through at least the end of 2039. In the GHG Glidepath scenario, natural gas plants are modeled to no longer be available to serve reliability needs beginning in 2040, in accordance with HB 2021 emissions reduction targets of 100% beginning in that year. In the Reliability Only and Continued



Progress scenarios, natural gas plants continue to be used for reliability and energy through the end of the planning horizon. The ability, or not, of natural gas plants to help meet reliability needs is reflected in portfolio analysis though forecasted system capacity needs. The increase in capacity needs in 2040, when existing natural gas plants are no longer available for reliability purposes in the GHG Glidepath scenario illustrates the impact that the loss of their capacity has on resource volumes.

While still available for reliability in the GHG Glidepath scenario, the natural gas plants are modeled to decline in usage for generation of energy to serve retail load along a linear glidepath. This decline results in an increase in energy need, which drives higher resource additions than in the Reliability Only or Continued Progress scenarios.

Under the Reliability Only environment, an emissions reduction constraint is not applied, allowing PGE to retain more thermal energy to meet energy needs, and reducing this driver of resource needs. The increase in resource additions from 2029 to 2030 in the Reliability Only - No NLL scenario is largely driven by the Colstrip plant exiting retail service at the end of 2029.

This is shown on slide 55 of the June 2026 roundtable presentation, where the extension of Colstrip through the end of 2034 (consistent with flexibility provided in SB 1547, the needs under the RO Core Growth Only (formerly RO No NLL) with Colstrip remain flatter from 2029 to 2030 and the increase in needs is observed later in the planning horizon, from 2034 to 2035.

Data Center - PGE has evolved the modeling around large load growth, including data centers, to create greater visibility into the forecasted impacts on resource needs, emissions and costs across customer classes. Large load, including data centers, are included in the Corporate Load Forecast which includes a low, reference and high case - providing the ability to assess changing impacts from varying volumes of load growth. However, the 2026 CEP/IRP does not specifically include scenarios that alter large load as firm versus non-firm. We will continue to evaluate and evolve our modeling as we move forward.

POWER ACT - As a result of the POWER Act and the conclusions under UM 2377, a Peak Growth Modifier mechanism was adopted to appropriately allocate costs across customer classes. The forecasted Peak Growth Modifier allocation assigns the growth-driven costs to the customer classes based on the proportional contribution to growth in system demand. Since the adoption of the PGM in UM 2377, IRP's prospective cost forecasts incorporate this cost-causation principle.

By allocating the costs associated with growth under the PGM, we maintain equitable cost allocation as intended by the POWER act.



PGE's understanding of the cost cap threshold as established in House Bill 2021 is that it applies to the total annual revenue requirement, and is not broken out or allocated across customer classes. As such, the Continued Progress scenario applies the forecasted 6% budget across resource needs for all customer needs. However, PGE did include scenarios within this 2026 CEP/IRP that consider Core Growth Only needs (excluding new large loads) to provide additional insight into the impacts on resource needs, emissions and costs.

Modelling of rooftop solar needs improvement - Proxy Resource

11. Slide 60: PGE's load forecast methodology uses historical data and tends to forecast residential use per customer, with rooftop solar generation treated as a reduction in load, similar to energy efficiency. This has the unfortunate result of locking on a fixed amount of rooftop solar generation in each scenario, and removes the option for having scenarios with more or less rooftop solar generation. One solution would be to add a rooftop solar proxy to the resource mix. This could be called Non-cost-effective RT solar, which assumes that the forecast amount represents the cost-effective limit, which we consider a questionable assumption.

PGE Response:

PGE's load forecast does not treat rooftop solar in the same way as energy efficiency. Estimated historical generation is "added back" to the historical usage series for model estimation. This allows for forecasting of underlying customer demand. The rooftop solar generation forecast is layered on top of the resulting customer demand forecast to provide a net load forecast. High and low cases for rooftop solar generation are included via the high and low load forecasts.

Since rooftop solar generation is already embedded as part of the net load forecast so it was not included again as a selectable resource option in order to avoid double counting. This is the first iteration of modeling VPP resources within the IRP analysis, and we plan on enhancing the model in the future. Your feedback is valuable and we will consider modeling of rooftop solar generation as a proxy resource option within the IRP analysis in the next iteration.

12. Modelling of rooftop solar needs improvement - Interaction with Batteries

A related question from the May 20 workshop is that the VPP Bins in Slide 74 do not include rooftop solar options, which deprives the VPPs of generation to drive their storage options. Also, only Bin 3 appears to have battery storage options.

One concern is that a residential battery system would have a very different charging cycle compared to a residential solar-battery system. Given that plugin solar and battery devices are gaining certifications and have been adopted by more than half a dozen states, we believe that the IRP/CEP should include scenarios that examine the potential of these devices, especially as their cost is much lower than traditional residential solar and battery installations. Such a scenario should be one of several scenarios created to examine other DER option, such as residential and commercial rooftop solar capacity driving substation-scale battery storage systems that can quickly provide needed new capacity while bolstering resilience and improving system utilization, which can lower costs for all consumers.

PGE Response:

Distributed solar generation is an important VPP resource which is accounted for as part of the net load forecast. Since it is already embedded as part of the net load forecast so it was not included again as a selectable resource options in order to avoid double counting. Low, reference and high adoption of distributed solar which provide needed new capacity and may contribute towards driving batteries in the system are already included in the model.

Since storage is covered in bin 3 it does not appear in the other bins.

Thank you for your feedback regarding assessing and including plugin solar and battery devices for inclusion in the VPP bins as part of the future-facing measures.

Storage currently uses an average load profile without separating out standalone storage and co-located storage. We agree that the charging profile for residential battery system is not expected to be the same as that of a residential solar-battery system in typical cases. Solar-battery system is expected to prioritize charging from on-site solar generation, while standalone battery system will prioritize charging during off-peak hours first and then during mid-peak hours. Mid-peak hours have an overlap with the time during which the on-site solar generator will be producing energy. This is the first iteration of modeling VPP resources within the IRP analysis. The suggested model with higher resolution would require enhancement in multiple methodologies to enable precise implementation. As the adoption of behind-the meter standalone storage and co-located solar-battery systems increase, we will assess the impact of this update and consider enhancing the model.

13. Average Event Capacity needs further explanation

Also, from the May 20 workshop, slide 75, can you better explain Average Event Capacity, describe how the incremental potential values were determined in the AdopDER model, and discuss the key assumptions behind the calculation. Given that cost reductions and significant transmission constraints are driving a greater role for customer-sited resources, the values in this slide seem extremely low. Are these values based on the new methodology for determining avoided cost? If not, when will that adjustment be made? How do you expect the new methodology to impact ELCC values for various DER/VPP resources?

PGE Response:

Average Event Capacity is the average MW load reduction expected to be available from a DR resource during modeled event hours, by season and bin, before applying ELCC accreditation.

Incremental MW potential is calculated by forecasting adoption of each applicable DR/VPP measure, applying measure-specific load-impact and event-performance assumptions, converting those impacts into seasonal average event MW, and then aggregating the measures into five bins based on dispatchability, load shape, and program similarity.

PGE's VPP portfolio orchestrates more than 600 MW of flexible capacity from over 230,000 participating customers, representing approximately 25 percent of PGE's customer base. Residential participation in PGE's VPP programs is approximately four times the national average. The average event capacity (MW) of VPP DR presented in slide 76 present the additional capacity that is forecasted to be available in different bins by the end of 2030 following reference case of DER adoption. It does not include the existing cumulative capacity of VPP resources already existing in the system.

These values are based on AdopDER 2025 Q3 forecasts and load-impact assumptions, not directly on the avoided-cost methodology. However, avoided-cost updates influence the economics of these resources through cost-effectiveness screening and levelized net cost inputs.

The new avoided-cost methodology is expected to affect the economics and selection of DER/VPP resources more directly than the ELCC percentages themselves. ELCC is calculated from hourly performance during reliability-critical periods in Sequoia, while avoided costs affect cost-effectiveness and levelized net cost inputs.

14. Modify the Cost Cap Scenario

Currently, the Cost Cap scenario stops implementation of HB 2021 the first time the annual cost cap is reached. Rather than suspend the program, it would be more informative if the scenario modelled HB 2021 implementation with a cap on allowed investment that is limited to 6% of the revenue requirement in every model period.

PGE Response:

The Continued Progress scenario does not suspend HB 2021 implementation the first time a cost cap threshold is reached. Instead, it applies an annual spending budget equal to 6% of the forecasted IRP revenue requirement in each model period. This budget constrains incremental investments beyond reliability needs while continuing to allow progress toward emissions reductions throughout the planning horizon. The methodology was intentionally designed to consider the alternative compliance pathways discussed in House Bill 2021. However, this is not intended to mirror a section 10 filing, the rules of which are still being finalized in AR 685. This planning scenario is intended to provide insight into a pathway that continues to make progress towards emissions reductions targets but balances those targets with reliability and affordability risks. PGE will continue to evolve this method in future planning cycles.

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Stakeholder: OPUC Staff

Organization: OPUC Staff

Applicable Public Meeting Date: Jun 10, 2026

Community Impact Metrics (Slides 7 - 26)

Purpose: Do you have any concerns on PGE's approach to tracking and/or quantifying CBIs and community impacts?

15. How does PGE define disadvantage/non-disadvantaged and is the definition consistent across metrics?

PGE Response:

At this time, the historical data being compiled for CBI tracking relies on metrics and data already available to PGE and the IRP team. As noted above, some of this may related to EPA and Justice40 initiatives and definitions. Disadvantage/non-disadvantaged definitions and related draft metrics and data presented align with those established processes.

Draft Portfolio Analysis Results (Slides 31 - 57)

Content: Are these results in line with your expectations? What questions do you have as it relates to these draft results?

16. Please explain whether PGE considers Colstrip to be available in the reliability only scenario.

PGE Response:

Colstrip is modeled as exiting PGE's portfolio at the end of 2029 in the Reliability Only Scenario. In four specific Colstrip extension scenarios (identified as portfolios #13-16 in the scenario table on slide 35 of the June roundtable) Colstrip is assumed to remain in PGE's portfolio for an additional 5 years, exiting the portfolio at the end of 2034.

17. Please provide the methodology and assumptions used to inform HB 2021 cost attribution in the cost cap scenario.**PGE Response:**

The 2026 CEP/IRP will include detailed narrative of methodology and assumptions for all scenarios. For the Continued Progress scenario as presented across 2026 Roundtables, a spending limit informed by HB 2021 Section 10 provisions is applied to the Reliability Only (RO) scenario assumptions, meaning the models are not constrained by GHG emissions limits, but achieve incremental additional emissions reductions compared to RO, as enabled by the availability of limited funds for incremental additional clean energy.

18. Please provide the resource cost, production, and COD assumptions for the Emerging resources.**PGE Response:**

For the 2026 CEP/IRP, the emerging resource is assumed available starting in 2035 for portfolio construction in ROSE-E.

For 2035 COD, the fixed cost is ~\$1,120/kW-yr (2026\$) and the average capacity factor is ~62%.

19. What factors lead to the lower selection of non-cost effective EE selected as compared to the 2023 IRP and IRP Updates?**PGE Response:**

First, due to the annual iteration of ETO's cost effectiveness screening analysis, the quantity of both cost-effective EE built into the load forecast and non-cost effective EE made available for selection in portfolio analysis is meaningfully different in the 2026 CEP/IRP compared to previous plans. Based on ETO's assumptions for the screening test this round, much more EE is found to be cost-effective and is already built into the load forecast. Remaining non-cost effective measures are grouped by similar costs into 5 bins for simplified inclusion in IRP and are made available for selection in portfolio analysis. Informed by the shift in ETO analysis, the NCE EE average bin costs are higher compared to last IRPs, as well as the total quantity available for selection is lower, since more lower cost EE measures have passed the ETO cost-effectiveness test.

Second, PGE also updates new proxy resource options and costs with each IRP analysis thus how these compare to and compete with other options available within portfolio analysis, such as non-cost effective EE, also changes.



Third, the above dynamics of costs and resource options available for selection interplay in any given year with need, which is based on the load forecast and the existing generating portfolio available. This range of differing assumptions and changing dynamics drive different results each IRP cycle.

20. How did PGE's changes to how it bins NCE EE impact the selection of those resources? For instance, what changes did PGE make to the ELCC values for each bin of NCE EE? Which bins of VPP and NCE EE were selected in each scenario and why?

PGE Response: On NCE EE uptake, see above response.

In case of VPP, different incremental capacities of the aggregated resources in the five VPP Flex Load bins are being selected for different scenarios. On analyzing all the scenarios it is observed that all of the incremental capacities that are forecasted to be available over the planning horizon for the current Flex Load programs (which are included in bins 1 and 2) are being selected in a large number of the planning scenarios. These are mature and cost-effective resources which are favored by the model in most scenarios as a resource option. A considerable portion of bin 3 is being selected in multiple scenarios although the net cost of this bin in this first iteration of the VPP model is based on its current small-scale implementation. This net cost is expected to decrease when these current small-scale programs or pilots will be expanded in the future. Bins 4 and 5 include emerging DER measures which have not yet been implemented, and a relatively lower portion of the available capacities of these bins are being selected in several of the planning scenarios. Bins 3, 4 and 5 become increasingly important for hedging uncertainty related to transmission expansion and procurement of non-emitting resources in an affordable manner.

21. What were the assumed costs of the gas contracts in cost cap and reliability scenarios?

PGE Response:

Gas contracts were modeled by CCCT proxy resources in Aurora. Levelized fixed costs for this CCCT proxy resource is modeled at approximately \$325/KW-year (2026\$) for a 2030 COD.

22. For PGE's DSG modeling, how much battery capacity is expected to be added?

PGE Response:

In the DSG model we have included incremental capacity assumptions for thermal technology-based DSG based on information regarding potential customers eligible to participate who have communicated interest. The use cases and operational models are more mature allowing their integration in the larger IRP analysis.

Battery-based DSG is an emerging type of DSG resource whose model development and evaluation is still in progress. Once the key model parameters related to these resources needed for IRP modeling have been determined and are considered mature, and there is less uncertainty related to the forecasted capacities, they will be included to further advance DSG modeling in our future IRPs.

23. On slide 44, are Emerging resources selected as the thin orange shade stacked around 5k MW?

PGE Response:

The thin orange portion of the stacked bar chart on slide 44 depicts CBREs. There are no Emerging resource additions in the portfolio through the timeframe shown in the figure.

24. Can you provide your non-retail emissions aligning with the three portfolios?

PGE Response:

This information will be made available in the 2026 CEP/IRP filing.

25. Did/could the Company consider a portfolio that reflects compliance with SB 1547 (meeting reliability needs with 2030 coal exits), and then see what needs remain to meet HB 2021 requirements? Does the HB 2021 cost cap capture this and/or does the HB 2021 cost cap scenario comply with HB 1547?

PGE Response:

PGE is required by ORS 757.518 (Section 1, Senate Bill 1547 (2016)) to eliminate the costs and benefits associated with coal-fired resources from rates by the end of 2029. This is different than exiting ownership or shutting down Colstrip, decisions that are tied to the complex ownership structure and associated obligations. As noted in the request, the law also gave PGE the option of continuing to include the costs and benefits, and thus the electricity, from Colstrip in rates until the end of 2034. This short-term exemption



recognized the potential cost or reliability impacts to customers of accelerating depreciation and the additional cost risks associated with market exposure and resource procurement.

All of the base scenarios comply with SB 1547 and assume that Colstrip exits the portfolio at the end of 2029, including the Continued Progress portfolio (formerly referred to as cost cap). Any scenario that extends Colstrip through the end of 2034 is clearly called out as a Colstrip extension.