Integrated Resource Planning

STAKEHOLDER FEEDBACK: February 24, 2026

Received: 03/04/2026

Stakeholder: Katie Chamberlain

Organization: Renewable NW

Applicable Public Meeting Date: February 24, 2026

1. Why does PGE assume either a 0% or 100% seasonal capacity benefit for transmission expansion options (page 66)? Is it possible that the capacity benefit provided by the Transmission options would be somewhere in between?

PGE Response:

PGE's assumption of either a 0% or 100% seasonal capacity benefit for transmission expansion options is interpreted as the likely ability (yes/no) of a transmission project accessing a market where PGE could procure a firm capacity backed contract. While it is possible that a capacity benefit could lie somewhere between 0% and 100% depending on the quantity of firm transmission procured, PGE's current cost assumptions are representative of a firm capacity resource.

2. The ELCC for 4-hr standalone storage appears low. Can you explain what factors are contributing to the ~20% winter ELCC?

PGE Response:

The Draft 2026 IRP 4-hr standalone storage ELCCs of 45% in Summer and 23% in Winter (shown in the July Rountable – Slide 47) are roughly equivalent to values published in the 2023 CEP/IRP Update (Table 20) of 46% and 22% for Summer and Winter, respectively. The ~20% Winter ELCC demonstrates the suboptimal role of short-duration storage in addressing winter adequacy events, as highlighted in the 2023 CEP/IRP Section 6.2.3.1 Energy sensitivity adequacy assessment of Preferred Portfolio. As a third-party comparison, the recent study of Resource Adequacy in the Pacific Northwest conducted by E3 suggests that Winter ELCCs of short-duration storage are <10% in the Pacific Northwest given the sensitivity of the region's system to hydro and winter energy constraints.

Received: 04/17/2026

Stakeholder: Carra Sahler, Alessandra de la Torre, Alma Pinto, Silvia Tanner, Alma Pinto, Paul Hawkins, Amanda Watson, Robin Straughan, Angela Crowley-Koch

Organization: GEI, Climate Solutions, NWEC, OSSIA, Portland, Hillsboro, Tualatin, Multnomah County

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3. Given the language in Order No. 24-096, we urge PGE to use this CEP/IRP cycle to drive a deeper understanding of how CBRE projects could be developed and deployed in a way that benefits communities and the utility. Our communities do not have time to wait for future CEP/IRP cycles. Rather, 2030 is right around the corner and PGE needs to build upon learnings from this initial RFO and gather additional information now to accelerate CBRE projects. PGE's CBRE procurement strategy should also be integrated with PGE's SSR actions to meet the 2030 compliance obligation.

PGE's proposal looks to reduce by more than 50% its 2030 assumed availability of CBRE (from 155MW to 60-70MW). We understand that PGE has proposed these modeling assumptions based on the market intelligence it collected through the one RFO it has released so far. We have several concerns about treating the RFO response as the ceiling for modeling CBREs in this CEP/IRP. For example, it seems unlikely that PGE could only find just above 20 MW-35 MW of CBREs in future CBRE procurement efforts targeting a 2030 COD, even if these were only through additional RFOs.

First, to engage more thoughtfully in this IRP/CEP (and to avoid the pitfalls present in the RFO), we need transparency around the CBRE RFO costs and how those compare to the IRP modeling assumptions. It is our understanding that PGE's 2023 IRP modeling efforts selected 155 MW of CBRE projects along with utility scale resources as part of a lowest-cost, lowest-risk portfolio due to transmission constraints. We ask that PGE include the complexity of pricing in their discussion of CBREs. While smaller projects do not achieve maximum economies of scale, they provide real reliability and resilience value by not using transmission and can continue to be part of a lowest-cost, lowest-risk portfolio in the 2026 IRP.

Second, since the RFO did not deliver what PGE's 2023 CEP/IRP identified as possible, we request that PGE eliminate unnecessary restrictions on what kind of resources could be successful. For example, standalone solar should be a requested

CBRE resource, instead of one accepted by bidders who responded with solar-only projects despite the minimum requirements.

We expect that PGE will use this modeling opportunity to more fully capture CBRE potential levels and price sensitivity to ensure this CEP/IRP cycle better captures the full market opportunity available in its territory. In our view, the results from this CBRE RFO should not artificially limit what PGE models in its CEP/IRP. In fact, the Commission's order directed PGE to consider broader procurement pathways beyond the RFO. Early stakeholder feedback articulated that the RFO approach was likely to capture only a portion of CBRE opportunities. The RFO learnings can support additional successful CBRE proposals and we encourage PGE to move forward with the next request for resources. For that reason, we recommend that PGE keeps its 155 MW assumed CBRE availability for the 2026 IRP, or at the very least that PGE significantly increases its assumed availability of CBRE beyond the currently proposed 60-75 MW.

Lastly, we would like more clarity on pricing. Smaller projects are more expensive, but offer the potential of a community benefit other than simply cash payments, for example in the form of energy resilience for a nonprofit or community organization. Providing energy resilience to an organization increases the cost of a project, but there was no guidance from PGE on whether that was desirable and would be accommodated in the pricing assumptions. Projects requiring community benefit explicitly will be more expensive but there was no guidance from PGE on pricing and costs in the RFO. Now that PGE has data from its first three rounds of RFOs it would be helpful for future procurement to provide a range of prices so applicants can understand if their project is appropriately scaled.

PGE Response:

PGE appreciates stakeholder feedback regarding CBRE modeling, procurement pathways, pricing transparency, and the role CBREs may play in advancing community benefits. PGE recognizes that the recent CBRE RFO may have provided limited visibility into standalone solar-only opportunities because the solicitation was structured around solar paired with storage and was not designed to independently evaluate standalone solar procurement potential. At the same time, PGE believes the assumptions used in the 2026 CEP/IRP should reflect the best available information on achievable CBRE potential, including procurement outcomes, demonstrated deployment, interconnection and siting constraints, financing feasibility, and project deliverability. Based on shortlisted and final offered projects advancing through procurement pathways, PGE proposes to reduce the near-term CBRE-Micro solar-plus-storage availability assumption to approximately 65 MW through 2030, reflecting market intelligence that viable solar-plus-storage CBRE projects were materially below the prior 2023 IRP assumption of roughly 100 MW.

Based on stakeholder feedback received on 2026 IRP modeling assumptions, for growing CBRE potential over time, PGE proposes to replace the prior assumptions with a market-informed estimate based on demonstrated historical deployment of QF and Community Solar PV projects in PGE's service territory. Approximately 86 MW of these projects have historically been developed, providing a reasonable indicator of achievable market scale under real development, interconnection, siting, and financing conditions. Beginning in 2032, proxy CBRE potential ramps up by an additional 43 MW of capacity, equivalent to approximately 50% of demonstrated historical QF and Community Solar deployment. This approach continues to put into action the bounds of the CBRE availability previously identified within the 155 MW CBRE potential from the 2023 IRP, while grounding the updated assumption in observable market activity.

PGE is not able to share project-specific pricing information at this time due to procurement confidentiality, but recognizes that community benefit and resilience elements may affect project costs and should continue to inform future procurement design. PGE will continue using procurement learnings to evaluate future CBRE pathways, including whether future solicitations should explicitly include standalone solar-only options and broader procurement approaches beyond the RFO structure.

4. PGE found in its CBRE Potential Study that there were nearly twice as many stand-alone solar resources available than solar paired with batteries. However, the CBRE RFO required batteries or other dispatchable products. It is true that PGE accepted solar-only bids that came through, but there would have been more bids submitted if the RFO had encouraged solar-only bids. Solar-only projects can provide direct community benefits and are more familiar for community organizations and local governments. These projects can also be enhanced through combining with demand response measures, or other energy infrastructure that increases flexible load or climate resiliency. PGE's future procurement actions should make the dispatchability criteria optional from the start in order to receive more solar-only bids. In addition, we encourage PGE to be innovative in its thinking; if projects are not able to include battery storage in their project, PGE should consider taking on that component of the project, and supply the battery to a solar-only project. Additionally, PGE should thoughtfully explore how to support low-impact hydro projects participating either in a future CBRE RFO or other CBRE procurement paths that PGE should explore.

PGE Response:

Thank you very much for your input. The amount of CBRE potential from the 2023 IRP was informed by a Community Lens Potential Study. Noting that the IRP is a planning tool, and not an operational tool, the 2023 IRP also modeled the Effective Load Carrying Capability (ELCC) for standalone solar in the Summer months at less than half (23%) of that for solar paired with storage (51%). The ELCC for standalone solar also drops in half in the Winter to just 12%. From a resource adequacy perspective, this presents clear gaps in operational needs. By structuring the CBRE RFO to allow for virtual pairing and requesting resource-specific pricing, we were able to gain market intelligence for both stand alone and solar paired w/storage. PGE kept the Bidder's time and energy in mind when requesting the resources that would deliver the most value to address our system needs and therefore be most likely to be selected.

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Received: 06/16/2026

Stakeholder: OPUC Staff

Organization: OPUC Staff

Applicable Public Meeting Date: February 24, 2026

5. Flexibility Study Draft Results (Slides 13 – 30)

Content: Do you have any comments or questions regarding the purpose and approach of the flexibility study, or the draft results?

The flex value, as presented on slide 23, looks like a subset of ELCC. Given that observation:

1) **does it start as a percentage?**
2) **please show the formula for how that original metric (a subset of unserved energy) derives a dollar value per kW-year as presented on slide, and**
3) **please confirm whether Rose-E uses these values as an input for resource selection.**

PGE Response:

1. Flexibility value is distinct from an ELCC, and not a subset. While both ELCCs and Flexibility values are derived by testing the marginal effect of resource additions, flexibility values are derived in a resource adequate system through production cost-simulation (GridPath) while ELCCs are estimated in a resource inadequate system through a loss-of-load probability simulation (Sequoia). The first answers the question of how does system cost change with respect to a marginal change while the latter answers the question of how does capacity need change with respect to a marginal change. The objective of a production cost simulation is to minimize net system costs, while a loss-of-load probability model does not consider economics and aims to minimize unserved enregy. Neither Flexibility value nor ELCC start as a percentage. ELCC is normally represented as a percentage as a comparative unit of measure that clearly demonstrates the diminishing marginal capacity contributions with greater resource staturation. However, ELCCs as modeled in PGE's IRP are measured in MW, then normalized by nameplate as: ELCC (MW) over Nameplate (MW) to derive a percentage.
2. Like an ELCC, there is not a closed-form equation used to derive the dollar value for flexibility value or integration costs. The dollar value is derived by comparing the net system costs of two different production cost simulations in GridPath.
3. Flexibility values for batteries and integration costs for VERs resulted from the Flexibility Study conducted by Sylvan Energy Analytics become part of costing of

proxy new resource options available for selection in ROSE-E. They are part of a net cost for each new resource option made available in portfolio analysis in ROSE-E, with the net cost view aiming to capture both costs and benefits of adding a given resource to the system. Section 6.7 of the 2023 CEP/IRP Update includes more information describing the cost and benefit elements in ROSE-E's net cost view, with Figure 91 showing an example of magnitude of how different costs and benefits impact a net cost for a blended resource considered in the year 2028.[1]

[1] https://downloads.ctfassets.net/416ywc1laqmd/UlLUBLOdenMjnrFJHv2mV/c382e175edae0e6ccffb806cd02bb6db/2023_CEP_IRP_Update_Errata.pdf#page=187.

6. CBRE Update (Slides 31 – 42)

Content: Is there interest in proxy CBRE categories for the IRP other than that informed by the RFO (i.e., only microgrids = solar + storage); such as standalone solar?

Staff feels the 2030 forecast for CBRE potential should be revisited. The CBRE RFO.25 that PGE based its decision to decrease the 2030 CBRE potential forecast from 155 MW to 60-75 MW was limited in the types of resources that could be offered. Additionally, based on prices of CBREs in PGE's 2023 IRP, the preferred portfolio likely would have procured more than 155 MW were additional CBRE resources available to the model. Staff recommends PGE test multiple volumes of CBRE resources including the 155 MW initial target plus an additional 179 MW volume to represent the SSR gap by 2030. Were the 2026 IRP to select 334 MW of CBRE resources, it would send another clear planning signal

Staff believes the decision to limit selectable CBRE resources to CBRE-microgrid (solar + storage) would unnecessarily limit valuable insights. The 2023 IRP's selection of standalone solar and in-conduit hydro suggest that energy resources without dispatchable capacity are also valuable to PGE's system. Artificially limiting which CBRE resources get modeled for selection would obscure valuable insights.

Staff believes that transmission constraints combined with off-system marginal resource pricing likely confer a higher avoided cost to CBRE resources than the assumed prices from the 2023 IRP used to score projects in this RFO. This dynamic has been noted by Staff and the Company in the past in Docket No. UM 1893, which reviewed avoided costs for PGE's 2023 IRP. Staff believes the 2026 IRP should create more clarity around cost-effectiveness and pricing. For these reasons, Staff recommends PGE model sensitivities around quantity, diversity, and pricing of CBRE resources in the 2026 IRP/CEP.

PGE Response:

PGE appreciates Staff's feedback and agrees that the prior CBRE quantity assumptions may have been too low, particularly for standalone solar opportunities not represented in the recent RFO. In response, PGE proposes to model approximately 65 MW of solar-plus-storage through 2030 (informed by the RFO final shortlist) and approximately 43 MW of additional capacity available after 2032. However, developing higher-volume sensitivities is challenging because the current market indicates these projects are small, relatively expensive, and difficult to procure, with interconnection costs and reduced future incentives further affecting economics. Modeling substantially higher quantities could therefore overstate demonstrated market availability and displace lower-cost or higher-impact resources in the portfolio. PGE believes the revised assumptions appropriately incorporate Staff's feedback while remaining grounded in current procurement and market conditions.

7. Diverse Market Transmission Framework (Slides 54 – 65)

Content: Any feedback for presenters?

Staff notes that Sylvan Energy Analytics' work on an updated method for marginal ELCC included a suggestion that this method might be employed to calculate a marginal ELCC for transmission. Staff wonders whether this method could be considered or explored to inform the relative value of potential transmission projects.

Does the Company's transmission framework reflect any changes associated with the envisioned acquisition of PacifiCorp's Washington territory? What, if anything, changes regarding transmission, associated with this sale?

See slide 65, is the table intended to reflect monetary costs and benefits, and if so, where and how are those reflected in the table? To what extent does transmission that connects to extra regional markets result in sales from PGE to markets versus purchases by PGE from markets? How does PGE reflect the value of sales from market access to customers? How does PGE's valuation consider trade offs between transmission's value in terms of bringing on additional resources and the value of accessing markets? What variables does the company consider in making these evaluations?

PGE Response:

PGE appreciates Sylvan's novel method for direct calculation of ELCCs through shadow prices and is exploring incorporating GridPath for analyses beyond the Flexibility Study, including Resource Adequacy, as part of future planning cycles. As the method described is novel, applying it to a portfolio of proxy resources in a well-defined power system optimization representing PGE's system is still hypothetical and unproven. With respect to a measure of relative capacity value of transmission projects, it is PGE's understanding that the capacity value of a transmission project is not intrinsic to the project itself. Instead, the capacity value reflects the generating resources or extra-regional markets each project accesses. As such, the costs and capacity benefits of transmission projects provide relative measures of value.

8. Portfolio Scoring (Slides 66 – 80)

Any other Feedback?

Staff notes that the new CBRs require that bids be evaluated using portfolio scoring metrics used in the IRP and wonders whether the Company envisions any limitations of uses the proposed metrics in this respect.

OAR 860-090-0060(7)(i) Preferred Portfolio. The utility must select a Preferred Portfolio in the IRP and explain why it represents the best balance of cost and risk to customers and the utility. The utility must include a visual representation such as a matrix that describes how each portfolio performed against the portfolio scoring metrics and that clearly demonstrates the relationship of the preferred portfolio to all portfolios eligible for preferred portfolio selection. In the event that the most competitive portfolio is not selected as the preferred portfolio, the utility must provide additional justification for the selection.

PGE Response:

PGE's understanding is that the CBRs require a utility to assess RFP portfolios using IRP scoring metrics (860-089-0475(5)). PGE agrees and has enhanced portfolio scoring in response to the new CBRs. In the 2026 CEP/IRP, PGE evolved portfolio scoring utilizing the Analysis of Risk Investments and Assets (ARIA) model (replacing the prior annual cost model, ART). ARIA expands on the annual cost analyses performed in ART, providing a deeper ability to identify risks, cost drivers and differences between how different technologies interact with various possible futures. This update was further discussed at the August 2026 roundtable.

9. ELCCs (Slides 81 – 99)

Content: Any feedback for presenters?

1. **Is Advanced_NE the only resource under the label Emergent on slide 90?**
2. **Why don't we see Advanced_NE on slides 88 or 89? Can we get a similar description as provided on those slides?**
3. **Please explain how resources get a higher ELCC than 100% on slide 91.**
4. **Also, given how resource capacity contribution interacts with other resources, please explain how the annual ELCC of these resources on slide 91 might differ.**
5. **Elaine Hart of Sylvan Energy Analytics recently issued a paper with an updated critique on the ELCC strategy and offered an alternative solution that appears elegant. Staff offers that the Company consider reviewing this paper to see if it affords opportunities to improve the method by which resources are assumed to contribute capacity. https://www.sylvan.energy/insights**

PGE Response:

1. Yes, there is only one resource under the label "Emergent" on slide 90, labeled "Advanced_NE." Since the February roundtable this resource is renamed "Emerging", meant to capture a firm dispatchable resource whose technology is yet unproven at utility scale, such as Small Modular Nuclear or Advanced Geothermal.
2. "Advanced_NE", referred to as "Emerging" in future roundtables and the 2026 CEP/IRP has the same capacity contribution as a combined cycle combustion turbine.
3. Resources can achieve an ELCC greater than 100% due to the capacity and energy interactions modeled in Sequoia which capture both the direct and indirect effects of a marginal capacity addition. For example, 1 MW of a resource such as energy efficiency can have a direct effect of reducing peak unserved energy by 1 MW while also reducing the energy demanded in the system during all other hours of the simulation. Reducing energy constraints in the system has an indirect effect of allowing other energy constrained resources, such as hydro, natural gas, or short-duration storage to more optimally dispatch to reduce peak unserved energy. For example, this indirect energy length in the system may allow the peak capacity short fall to be reduced by another .1 MW, resulting in an ELCC of 110%
4. Interactions are endogenously captured in PGE's Resource Adequacy model Sequoia. These are present in both the Summer and Winter ELCCs and fundamentally do not change with a "annual" simulation, i.e. a simulation that contains all months of the year rather than the 6 months associated with one season or the other. It is the weighting of the loss of load curve (see slide 18 of Jan. '25 Roundtable) that changes in an annual simulation with both summer and winter peak

capacity shortfalls influencing the annual ELCC. Generally, the resulting ELCC from an annual simulation lands between a summer and winter ELCC, intuitively overestimating the winter contribution of a resource and underestimating the summer contribution.

5. While PGE's current RA model used to calculate ELCCs is an optimization-based solution, it is more akin to the "Marginal Reliability Improvement" described by E3, as the objective of the optimization is to minimize unserved energy, rather than minimize system costs. PGE appreciates Sylvan's novel method for direct calculation of ELCCs through shadow prices and is already exploring incorporating GridPath for analyses beyond the Flexibility Study, including Resource Adequacy, as part of future planning cycles. It is important to note that Sylvan's description of the novel method does not include examples of outputs and how they compare to a "Marginal Reliability Improvement" approach. As the method is novel, applying it to a portfolio of proxy resources in a well-defined power system optimization representing PGE's system is still hypothetical and unproven.