

Integrated Resource Planning



STAKEHOLDER FEEDBACK: August 27, 2026

Received: September 4, 2026

Stakeholder: Katie Ware & Mike Goetz

Organization: Renewables Northwest

Applicable Public Meeting Date: August 27, 2026

September 4, 2026

Portland General Electric

2027 CEP/IRP

Re: Feedback of Renewable Northwest, PGE's August Roundtable Meeting

I. INTRODUCTION

Renewable Northwest ("RNW") appreciates the opportunity to provide feedback on Portland General Electric's ("PGE") August 27, 2026, CEP/IRP Roundtable. RNW addresses in these comments the four issues that are central to the current planning cycle: granular emissions modeling, the pace of clean resource procurement, transmission utilization and expansion, and the treatment of storage as penetration increases. As an update to the previous planning cycle, PGE is now using hourly emissions analysis to change the resource composition of the preferred portfolio, has updated its load forecast and near-term resource needs, has incorporated more granular transmission limits, and has proposed a specific transmission Action Plan that includes grid-enhancing technologies ("GETs").

RNW supports this direction. The current analysis begins to connect the statutory emissions trajectory to the quantity and type of resources PGE must actually acquire. The key remaining questions are correspondingly narrower: whether PGE has fully optimized the cost of meeting HB 2021 at hourly granularity; how much of the modeled cost and resource need is attributable to large-load growth rather than the emissions trajectory; whether storage duration and portfolio interactions are represented adequately at



higher penetrations; and whether PGE's GETs commitment can be translated into project-level actions during the Action Plan period.

II. FEEDBACK

A. HB 2021 Compliance Pathway and Hourly Emissions Modeling

RNW's response to PGE's 2023 IRP/CEP Update included support for PGE's new hourly emissions accounting framework but noted that the analysis was at that point primarily an operational demonstration: PGE used the production cost model to constrain thermal generation and unspecified purchases, dispatch storage, and fill remaining needs with clean purchases while remaining within the 2030 emissions limit. RNW asked how those planning assumptions would translate into operations. PGE has now taken an important additional step—hourly emissions modeling now directly changes the resource buildout used for the Preferred Portfolio. PGE first constructs the GHG Glidepath portfolio in ROSE-E, then uses AURORA PZM to determine the additional resources required to close the hourly emissions gap, and finally uses ARIA to select the least-cost combination of those resources across futures. PGE reports that the resulting Preferred Portfolio contains 6,730 MW of cumulative new resources by 2030 and 9,020 MW by 2032. Of the 2032 additions, 992 MW, or approximately 11%, are specifically needed to ensure hourly attainment of the HB 2021 targets. PGE's AURORA analysis also shows that the incremental requirement grows quickly after 2032, with SE Washington hybrids appearing least cost through 2034 and an emerging clean-dispatchable proxy becoming the lower-cost option beginning in 2035.¹

RNW supports the rigor of this approach. It confirms the concern underlying our 2025 comments: annual emissions accounting alone can underestimate the resources needed to maintain a compliant portfolio. At the same time, the 992 MW increment should not yet be treated as an unchangeable "cost of hourly compliance." PGE's AURORA step tested three resource types—hydro, SE Washington hybrids, and an emerging resource—before ARIA selected among them. PGE should explain which hours and system conditions create the incremental need and whether the same analysis changes if additional storage durations, long duration storage, or other non-emitting flexibility resources are allowed to compete. This would help stakeholders understand whether the hourly-compliant portfolio has been optimized across the full set of plausible resources rather than only the three options tested to close the gap.

B. Updated Load Forecast, Affordability, and the Action Plan

The updated corporate load forecast materially changed PGE's near-term portfolio results. The May 2026 forecast reduced the 20-year total-energy growth rate from 3.8% to 3.6% and industrial growth from 7.2% to 6.8%, while industrial load remains the dominant source of growth. PGE's reference case assumes the existing data-center segment of approximately 400 MW doubles by 2030 and reaches about 2 GW by 2037.²

These are large portfolio changes from relatively recent input updates and underscore the value of a staged Action Plan rather than treating any one modeled buildout as a fixed procurement requirement.

The same distinction is important for affordability. Under reference-future assumptions, PGE reports a 20-year NPVRR of \$53.922B for the GHG Glidepath and \$38.303B for Continued Progress, a difference of approximately \$15.6B. ARIA improves the selected portfolios modestly—to \$53.105B for the Preferred Portfolio and \$38.099B for the selected Continued Progress portfolio—but the gap remains substantial. In the Core Growth Only cases, by contrast, the GHG Glidepath NPVRR is \$42.939B, and Continued Progress is \$32.829B, a difference of approximately \$10.1B. The roughly \$5.5B difference between those spreads demonstrates that large-load assumptions are materially affecting the headline cost comparison.³

For that reason, RNW recommends that PGE develop an hourly-compliant Core Growth Only GHG portfolio using the same AURORA/ARIA process used to produce the Preferred Portfolio. The existing Core Growth Only table shows the cost of the ROSE-E GHG portfolio without new large-load growth, but it does not show the additional resources or costs required for hourly compliance under that load case. An apples-to-apples comparison would provide a clearer measure of the resource and cost implications of HB 2021 independent of incremental Schedule 96 growth and would help prevent the difference between the reference-case Preferred Portfolio and Continued Progress from being characterized as the standalone cost of Oregon's emissions policy.

PGE's analysis of the Peak Growth Modifier in UM 2377 is useful context. PGE estimates that residential peak load accounts for approximately 21% of the modeled growth allocation while data centers account for approximately 77%. When PGE models the proposed mechanism, residential costs decline and data-center costs increase because generation and transmission assets built to serve growth are allocated to the classes causing that growth.⁴ RNW supports carrying this analysis into the final CEP/IRP. Systemwide NPVRR results are not, by themselves, a forecast of residential customer impacts, particularly where a large portion of the incremental investment is driven by new industrial load and is subject to a separate cost allocation mechanism.

RNW also supports the structure of PGE's draft utility-scale Action Plan. PGE proposes to acquire approximately 3,000 MW of wind, solar, and hybrid battery storage that maximize existing transmission service plans, followed by an additional 1,800 to 5,700 MW informed by procurement progress, updated need, and project costs. PGE also retains separate actions for energy efficiency, VPPs, CBREs, and transmission.⁵ This is a reasonable response to both the magnitude of the modeled 2030 need and the uncertainty demonstrated by the recent forecast revisions. However, the annual CEP/IRP updates should transparently compare contracted and deliverable resources against the

remaining 2030 hourly emissions gap and identify when additional procurement is required.³

C. Resource Adequacy, ELCC, and Storage Duration

In the July Roundtable, PGE used Sequoia to perform an hourly simulation of the portfolio and found that the main portfolios are resource adequate in 2030 and 2032. The same analysis identified increasing antagonistic interactions at higher penetrations: by 2035 and 2040, the portfolios begin to show remaining capacity needs that are not visible when individual-resource ELCC curves are simply added together. PGE estimates, for example, that about 12% of effective capacity is lost to interactive effects in the Reliability Only portfolio in summer 2035.⁶ This is a useful advancement from the 2023 methodology.

The updated load forecast also changes storage value in important ways. PGE explains that the shifting of summer peaks slightly earlier creates improved overlap with solar generation and reduces the value of shifting energy, while decreased winter loads generally reduce the likelihood of multi-day reliability events and increase the value of energy shifting. PGE therefore moved the ELCC test year from 2030 to 2032 to align with the Action Plan period. These results reinforce why storage ELCC should be treated as portfolio- and duration-dependent rather than as a fixed accreditation value.

Recent analysis reinforces this point. PowerGEM's August 2026 PNW ELCC sensitivity study found that storage accreditation varies materially with duration, penetration, hydro operations, regional topology, and the reliability metric used. Across the cases studied, longer-duration storage consistently retained greater capacity value as penetration increased, while the residual reliability risk shifted toward longer-duration events after substantial storage deployment.⁷ These results reinforce the importance of testing multiple storage durations rather than generalizing the declining marginal ELCC of a single duration across the portfolio.

PGE's February resource set includes 4-hour and 6-hour Li-ion batteries, 100-hour iron-air storage, and 10-hour pumped hydro, while 8-, 16-, and 24-hour Li-ion batteries were removed based on RFP-informed resource assumptions.⁸ Given the scale of storage in the Preferred Portfolio—including 1,979 MW of hybrid batteries by 2032—RNW continues to believe duration deserves more explicit analysis. PowerGEM's PNW analysis shows why: at increasing penetrations, 8-hour storage retains materially more marginal capacity value than 4-hour storage, while still longer-duration storage retains more value than either. PGE should report the marginal summer and winter ELCC curves used for 4- and 6-hour Li-ion storage and test 8-hour Li-ion as a sensitivity. The objective is not to assume that longer-duration BESS will be selected, but to determine whether increasing duration preserves capacity value as shorter-duration storage saturates the highest-risk hours and

whether that changes the quantity of renewables or hourly compliance resources required.

The ARIA results underscore the need to review this issue. In Continued Progress, ARIA selects 50 MW more storage and 107 MW more emerging resources than the ROSE-E reference build, while reducing wind and hybrids. In the GHG Glidepath, ARIA moves in the opposite direction, selecting 511 MW less storage and 168 MW more solar.⁹ PGE explains that solar performs as a more stable, lower-risk asset across futures, but the aggregated “Storage” category obscures which durations and technologies are driving the result. PGE should disaggregate that category and explain how storage duration, charging opportunity, ELCC saturation, and technology-cost futures affect ARIA’s selection. PGE should also clarify the battery duration and ELCC methodology used for the wind-solar-storage hybrids that make up a large share of the Preferred Portfolio.

D. Transmission Planning and Grid Utilization

In feedback on PGE’s 2023 IRP/CEP Update, RNW supported PGE’s three-circle transmission analysis and its plans to deploy dynamic line ratings, conductor coatings, topology optimization, and advanced conductors, while asking for more information on the impact of those measures. PGE’s latest analysis shows why greater granularity matters.¹⁰ BPA’s updated North of Pearl transfer capability increased the modeled non-firm capability available to ROSE-E from 712 MW to 1,380 MW and replaced a single annual limit with seasonal limits. PGE reports significantly fewer constrained and congested hours in 2035 as a result.¹¹ That change contributed to lower near-term resource additions and is a concrete example of how more accurate transmission representation can avoid unnecessary resource buildout.

PGE’s draft transmission Action Plan is also substantially more concrete than the narrative available in the previous plan. PGE proposes to advance the Warm Springs Power Pathway, North Plains Connector, and Harborton-Trojan #3 projects, while maintaining options for additional regional transmission. RNW supports those actions. PGE’s GETs action, however, remains comparatively general: Action 6.1 states that PGE will “Execute GETs strategy” to enhance local transmission.¹² In the final plan, RNW recommends identifying at least one or two candidate constraints or projects where a GET can move from strategy to deployment during the Action Plan period, with an estimate of the transfer capability, congestion relief, cost, and schedule benefit. That would make the GETs action measurable and allow future CEP/IRP updates to evaluate actual grid-utilization improvements.

RNW also continues to see value in a targeted conditional-firm transmission sensitivity. PGE no longer models conditional firm products in ELCC because most conditional firm bids in the 2025 RFP were bridge products expected to convert to firm service within several years. That is a reasonable basis for the reference assumption, but it does not

answer whether bridge service can lower cost or accelerate near-term renewable and hybrid additions relative to requiring firm service from the outset. PGE should test that question using appropriate energy and capacity derates during the conditional-firm period. This analysis would complement the major transmission projects in the Action Plan.

E. Post-2035 Resource Planning

PGE's latest analysis increasingly relies on an "emerging" clean-dispatchable resource after 2035. RNW agrees that specific post-2035 quantities should be treated as directional. PGE's ARIA framework is well suited to this problem because it can test fixed portfolios across many futures and identify when a resource choice that appears least-cost under the reference future creates material cost or risk exposure elsewhere. As PGE approaches the 2035 and 2040 HB 2021 milestones, future CEP/IRPs should progressively replace generic emerging-resource assumptions with technology-specific sensitivities as commercial information improves.

Long-duration and multi-day storage should remain explicit in that work. PGE already includes 100-hour iron-air storage and 10-hour pumped hydro in the candidate resource set, and the new hourly emissions and Sequoia results make their potential value increasingly relevant. PowerGEM's PNW analysis similarly found that longer-duration storage retains substantially more capacity value as storage penetration increases and that, after significant storage deployment, residual reliability risk shifts toward longer-duration events. Keeping long-duration storage visible as a distinct option will allow PGE to determine whether it becomes economic before, at, or after 2035 rather than effectively presupposing that timing through a generic emerging-resource proxy.

III. CONCLUSION

RNW thanks PGE for its consideration of this feedback. We look forward to continued engagement in future roundtable meetings supporting development of PGE's 2027 CEP/IRP.

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References:

- 1 PGE Aug. 27 Roundtable at 37, 53.
- 2 PGE July 22 Roundtable at 55-56.
- 3 PGE Aug. 27 Roundtable at 43-44.
- 4 PGE Aug. 27 Roundtable at 46.
- 5 PGE Aug. 27 Roundtable at 60, 65.
- 6 PGE July 22 Roundtable at 80-82.
- 7 PowerGEM PNW ELCC sensitivity study at 10-12 (Aug. 2026), available at https://renewablenw.org/sites/default/files/ReportsFact%20Sheets/PowerGEM_Renewable%20NW_ELCC_Sensitivity_Report.pdf.
- 8 PGE Feb. 24 Roundtable at 87-89.
- 9 PGE Aug. 27 Roundtable at 36, 39.
- 10 Aug. 11, 2025, Comments of RNW on PGE's 2023 IRP/CEP Update (OPUC Docket LC 82).
- 11 PGE July 22 Roundtable at 8, 55.
- 12 PGE Aug. 27 Roundtable at 66.

PGE Response:

Thank you for the feedback and continued engagement in our resource planning processes. We have reviewed this feedback and will continue to evolve resource planning work with these items in mind. We look forward to continued engagement and discussions as we file the 2026 CEP/IRP and work towards the Update that follows.

Received: September 8, 2026

Stakeholder: OPUC Staff

Organization: OPUC Staff

Applicable Public Meeting Date: August 27, 2026

1. Resource CBIs (rCBIs) (Slides 8 - 17)

Summary: PGE continues to develop and apply CBIs in the 2026 CEP/IRP through CBRE cost analysis, updated portfolio benefit scoring, and a tracking framework for informational CBIs.

These updates are intended to better reflect community benefits in portfolio assessment and support continued evaluation in future planning cycles.

Any Other Feedback?

See the chart on slide 13. Can PGE provide a “continuous progress” CBRE builds sensitivity analysis with and w/o rCBIs? Additionally, can PGE describe how CBREs perform/are selected in the continuous progress portfolio.

Please derive how PGE determined that CBRE resources cost \$449/kW-yr when RFO results came in below 2023 IRP modeled results of \$114/kWh and \$22/kW-mo.

PGE Response:

PGE performed the rCBI sensitivity analysis for the GHG Glidepath and Reliability Only portfolios to reflect the likely range of outcomes. Given other portfolio results, it is likely the Continued Progress results could fall in between the two.

PGE presented draft CBRE build out for the Continued Progress portfolio on slides 54 and 55, with more detail to be included in the 2026 CEP/IRP.

The proxy CBRE resource costs for the 2026 CEP/IRP were directly informed by the average costs across viable 2025 CBRE RFO bids for solar plus storage projects. The \$449/kW-yr (2026\$) cost shown on slide 12 is for a COD of 2032, with more detail and years of assumptions to be included in the 2026 CEP/IRP.

2. Portfolio Scoring (Slides 25 - 47)

Summary: PGE reviewed key metrics for all portfolios and utilized the ARIA tool to identify exact portfolio buildouts that performed the best from a least-cost, least-risk perspective. The GHG Glidepath portfolio that performed the best has been selected as the Preferred Portfolio. The best performing Continued Progress portfolio will also support the 2026 IRP's near-term Action Plan.

Any other feedback?

Does PGE plan to report the annual near-term cost for Portfolio Scoring Results in its filing (see Slide 43)?

Per rule 860-090-0060(g)(A) and (B), Staff would like to see both Long-term costs and present value of the expected net costs and near-term costs estimated as a plausible range for the total annual net costs to Oregon customers over the next five years associated with a given portfolio of resources, including all costs associated with producing, purchasing, and transporting energy to the customer (comprehensive near-term cost estimate), considering near-term uncertainties such as resource ownership and cost allocation to Oregon customers. How does the relative increase in procurement in 2030 impact customer rates? (Slide 53).

PGE Response:

Per rule 860-090-0060(7)(g)(A) and (B), yes, PGE intends to include both near- and long-term cost metrics in the scoring table. Draft values were presented at the August Roundtable. The scoring table reflects results in a given row for a specific portfolio i.e. resource buildout for a particular set of futures assumptions. Additional portfolio results and costs will be presented in the 2026 CEP/IRP and provided in the Standard Information Request data-based filing. Cost ranges can be thought of as the individual results across different portfolios and futures from within a particular scenario design.¹

PGE does not estimate customer rate impacts in relation to CEP/IRP portfolio analysis results for a range of reasons. For example, generation resources selected and operating conditions are based in proxy costs and locations and may not be reflective of real-world current or future resource options. Similarly, the commercial structure used to procure a specific resource (i.e., owned vs. contracted) is not known when developing IRP. Further, such costs are subject to future rate proceedings where their impact on rates of specific customer classes depends on the outcomes of those proceedings. Therefore, PGE believes rate proceedings are the appropriate processes for assessing rate impacts as

¹ See August 2026 Roundtable slide 27 for more on this terminology and how the terms fit together.

these proceedings deal with rate impact variables such as capital structure, cost of capital, class allocation, rate design, and other operation and administrative costs.

3. Draft Action Plan (Slides 58 - 68)

Content: Do you understand how the actions identified connect to the portfolio analysis results discussed earlier? Are there additional actions PGE should consider based on portfolio results?

Staff would appreciate if the Company would provide references to the associated Roundtable meeting and slides that provide the content supporting each of the action plan items.

PGE Response:

Portfolio analysis results, including selection outcomes of each resource type for key portfolios, were presented three times: in the June meeting, the July meeting and the August meeting. Additional discussion, and specific slide reference, are provided below.

1. Resource Planning Action - Not applicable. These actions relate to IRP requirements as found in IRP rules.
2. Energy Efficiency Action
 - a. December Roundtable - Energy Efficiency Section
 - b. July Roundtable - Slide 61
3. Virtual Power Plant Actions
 - a. May Roundtable - VPP Section
 - b. July Roundtable - slide 61
4. CBRE and SSR Actions
 - a. July Roundtable - slide 61
 - b. August Roundtable - Resource CBIs Section
5. Utility Scale Resource Actions
 - a. July Roundtable - slide 60 and 61
6. Transmission Actions
 - a. July Roundtable - Transmission Expansion Section

Additional detail will be provided in the 2026 CEP/IRP filing.

Regarding OAR 860-090-0060(7)(C), please confirm whether the Company has evaluated portfolios that test the impact with and without the proposed transmission actions.

PGE Response:

Yes – PGE evaluated portfolios where no transmission expansion is available. PGE also evaluated portfolios where specific transmission lines were not available (WSPP, NPC and Harborton Trojan #3). Additional details, and results, will be available in the 2026 CEP/IRP.

4. Any other feedback?

Staff would like to understand how the actions align with the near-term cost impacts and anticipated broader near-term costs to better consider how new actions fit into the context of anticipated costs not historically/traditionally captured in IRPs.

Staff expects the action plan to include necessary elements and details as specified in the new IRP rules 860-090-0060(10) (a) - (f). In particular, Staff encourages the Company to include reasonable ranges where they apply.

(10) Near-term action plan. The utility must include in the IRP a near-term action plan that describes the steps the utility intends to take over the next five years to provide customers with safe and reliable service, meet other customer needs and comply with all federal and state energy policies in a manner that is informed by the utility's portfolio analysis and consistent with the utility's long-term resource strategy. The utility must include in the action plan the utility's plans for:

(a) Resource acquisitions, including conducting competitive acquisitions, with information on the utility's intended schedules, estimated range of procurement scope or size, and any constraints or parameters that the utility intends to apply to align resource selections with the utility's near-term needs and long-term resource strategy.

(b) Pursuing energy efficiency, demand response, community-based resources, and other customer-sited and distributed resources. The action plan must explain how the utility intends to pursue all cost-effective energy efficiency and demand response and must reference analysis in the IRP that supports targets for using these resources to meet system needs.

(c) Any other resource actions the utility intends to take that may materially affect the utility's resource portfolio or the performance of the portfolio in terms of cost, risk, reliability, or compliance with state or federal policies.

(d) Any enabling strategies the utility plans to pursue to support the utility's near-term action plan.

(e) Preparing and filing the next IRP and IRP Updates, including the intended filing dates and any areas that the utility plans to prioritize for new or updated analysis.

(f) Managing near term uncertainties and process dependencies, including any contingency plans the utility has developed to implement the action plan as conditions change.

PGE Response:

See PGE's response to the previous question regarding the inclusion of outputs for near-term and long-term costs. PGE's analysis of cost impacts by customer class includes an extrapolation of non-IRP costs, which assists in comparisons between scenarios. Cost-competitiveness of all actions will be reviewed in subsequent regulatory filings (e.g., energy efficiency avoided cost updates, VPP multi-year plan, RFP final shortlist filings) as PGE proceeds with implementation.

PGE's Action Plan was developed to address the requirements of 860-090-0060(10). Ranges are incorporated primarily within actions for utility-scale clean energy acquisition, as this action is the largest in terms of MW and cost, and MW targets by year for other resource actions imply false precision as to the costs and availability of specific resource categories. Rather than project MW ranges for other resource types within the Action Plan, PGE intends to inform efforts to acquire resources where cost-competitive with IRP analysis and compare progress to portfolio results.

Received: September 10, 2026

Stakeholder: Pat DeLaquil

Organization: MCAT

Applicable Public Meeting Date: August 27, 2026

5. Content: Has PGE well explained how its rCBI method in the 2026 IRP differs from the 2023 IRP Update?

Please accept these comments from your August 27, 2026 IRP/CEP workshop on behalf of Mobilizing Climate Action Together, Multnomah County Office of Sustainability, Coalition of Communities of Color, Green Energy Institute at Lewis & Clark Law School, NW Energy Coalition, and Climate Solutions. We have questions and feedback about PGE's modeling decisions for Community Based Renewable Energy (CBRE) projects. We recognize that we missed the requested submission date of September 4, but needed time to digest the material in order to properly form our questions and feedback. We request that you consider this slightly delayed submission.

1. Feedback: Impact of rCBIs on CBRE implementation

While it's encouraging that the GHG Glidepath scenario adds CBREs early with or without the rCBI benefit, the amount of expected CBREs is quite low, especially compared to the low upper bounds that PGE is employing on this proxy resource. Please explain the slow uptake of CBREs.

Please also explain how resilience as a benefit from CBREs is or is not contemplated by the rCBI approach?

We would also like further information about how the model captures the benefit of avoided transmission upgrades with CBRE projects.

We have concerns about PGE's modeling decisions in the 2026 IRP/CEP, and how they are impacting the low number of megawatts that the model selected for the portfolios that PGE presented at the meeting. For its 2023 IRP/CEP, PGE considered a much broader set of resources under the umbrella of CBREs. In contrast, PGE only modeled microgrids as CBREs this time around. Microgrids are an important type of CBRE, and we welcome and support additional microgrids in PGE's system. However, HB 2021's definition of CBREs does not require a microgrid configuration for a reason to count as a CBRE. Instead, it

requires renewables plus a community benefit. PGE only modeling microgrids as CBREs in the 2026 IRP/CEP raises concerns about PGE choosing a CBRE that could be in the upper bound of costs compared to other CBRE options in the 2023 IRP/CEP, like community-scale solar. We are concerned that this decision can contribute to the low quantities of CBREs showing up in the PGE portfolios under consideration and presented at the last workshop, and we find PGE's modeling choice unreasonable.

PGE Response:

Thank you for your continued engagement around PGE's resource planning process and CBRE modeling. CBRE additions vary across the three scenarios, for example, with 0 MW in the Continued Progress portfolio, 2 MW in the Reliability Only portfolio, and 27 MW in the GHG Glidepath portfolio by 2032. The volumes of CBREs selected are influenced by the policy constraints of each scenario and the CBRE cost assumptions for this planning cycle, which were informed by viable 2025 bids in the CBRE RFO.

To better understand which price points would make CBREs more competitive in the resource buildout model, and potentially reflect monetization of community benefits, the CBRE cost assumptions reflect a reduced cost after 2032 to represent a resource community benefit indicator (rCBI). A sensitivity analysis was conducted in ROSE-E for the GHG glidepath and Reliability Only scenarios in which the rCBI cost reduction for CBREs was excluded to represent costs for the proxy CBRE resource in portfolio analysis more similar to the market data from CBRE RFO learnings. Comparing resource selection with and without rCBIs helps demonstrate the extent to which the assumed rCBI value influences the selection of CBRE resources in cost-optimized portfolio analysis. Additional details will be provided in the 2026 CEP/IRP filing.

6. Impact of rCBIs on Energy Efficiency and Demand Response

We understand that PGE has reconsidered the approach it took in its 2023 CEP/IRP Update, which applied rCBIs to apply to energy efficiency, demand response, and CBREs. In review and preparation for the 2026 CEP/IRP, PGE concluded that this modeling approach may have double counted the value provided by energy efficiency, and that it was simpler to avoid applying the rCBI to demand response. However, such an approach means the company is not capturing the complete rCBI value of demand response anymore. Is it possible that the model might have selected more demand response if rCBI was applied?

PGE Response:

On review of prior methodologies, PGE determined applying any rCBI benefit to energy efficiency or demand response costs did not make sense for this CEP/IRP. For energy

efficiency, application could result in double-counting of non-energy benefits already accounted for in NCE EE costs. For demand response, any benefit was only relevant to bin 3 of the new VPP approach and only applicable to residential batteries and was effectively deemed too small of an impact to warrant inclusion.

Content: Do you understand how PGE evaluated portfolios in the portfolio scoring process?

7. Integrating pCBI scores into selection of the “least cost least risk” portfolio

Slide 43 provides draft Portfolio Scoring Results but with no explanation about how the results will be used to identify the Preferred Portfolio. Slide 24 from the June 10 workshop stated 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. Is this still the case? If so, we continue to 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.

PGE Response:

pCBIs provide an important dimension for consideration in the comparison of portfolios and are included in the portfolio scoring matrix presented in the IRP for this purpose. Inclusion of pCBIs in the portfolio scoring matrix allows for the relative level of pCBI provision to be compared across portfolios. Selection of a Preferred Portfolio ultimately requires identifying a reliable portfolio with the ability to meet all regulatory requirements while balancing tradeoffs across portfolios between cost, risk, and the ability to provide other valued benefits to the community.

Content: What additional details would be helpful to understand the Preferred Portfolio and selected Continued Progress portfolio?

8. CBRE and SSR Acquisition Actions

Slide 64 identifies acquisition volumes of 0-27 MW of CBREs through 2032 and 448-669 MW of SSR-eligible resources for the 2030 compliance year. Please explain the very marginal uptake of SSR projects relative to the legal target of 10% of aggregate electrical capacity. Can you clarify the projected amount of SSR projects needed for PGE to demonstrate compliance with ORS 469A.210(2)(a) (small scale renewable acquisition mandate)? Without context, it is not clear which part of the range (high, medium or low) the company is legally obliged to acquire. How will PGE design the proposed 2027 SSR RFP to ensure compliance with the SSR requirement by 2030?

PGE Response:

It is accurate that the way PGE has chosen to model the CBRE proxy resource option (as a solar plus storage microgrid smaller than 20 MW is size) is that it is a small-scale resource and qualifies to contribute toward the SSR target; though in reality not all CBREs may contribute. PGE does not include other proxy “small” resource options, such as options that might be considered reflective of QFs, as available for selection in portfolio analysis due to the range of uncertainties in resource type, cost, location, and availability. PGE will include analysis and discussion in the CEP/IRP to examine proxy SSR target compliance analysis based on portfolio analysis results and potential proxy costs for small-scale resource types.

Content: Do you understand how the actions identified connect to the portfolio analysis results discussed earlier? Are there additional actions PGE should consider based on portfolio results?

9. VPP Targets

Slide 67 lists a long-term goal of integrating VPP expansion with customer growth while advancing the long-term goal of VPP contributing 25% of peak system needs by 2030. Please expand further about how the company envisions achieving this goal. For the ease of staff and stakeholders, please also incorporate into this section of the IRP useful and relevant information from the company’s distribution system plan.

PGE Response:

PGE’s plan for advancing the long-term goal of VPP is discussed in the 2026 IRP document.