

Resource Planning Advisory Group feedback report

Meeting details

- Tuesday, August 25, 2026, 1:00 p.m. - 3:00 p.m.
- Virtual webinar hosted by PSE and facilitated by Maul Foster & Alongi
- Links to:
 - [Presentation](#)
 - [Agenda](#)
 - [Meeting recording](#)

Feedback

The following records participant questions and PSE responses from the public comment opportunity and comments submitted via online [feedback form](#) or email to isp@pse.com. Meeting materials are available on the [clean energy planning website](#).

PSE endeavors to provide clarity in responses but subsequent follow-up may be required at times. Please direct any follow-up clarifications to isp@pse.com. *PSE responses are in teal italics.*

2. RPAG member feedback

Quinn Weber on behalf of the Washington Utilities and Transportation Commission staff, September 1, 2026 via isp@pse.com

Emerging Tech:

Slide 17: What causes mid-duration and long-duration storage to be available in the same year despite mid-duration storage being farther along the TRL curve?

The first-year availability assumptions reflect both technology readiness and PSE's current view of when each resource type could reasonably be available for utility-scale planning and procurement. While mid-duration storage may be farther along the technology-readiness curve, the modeled availability years also account for commercialization, supply-chain maturity, project development timelines, and the need for sufficient market evidence before including a technology as a resource option. For this draft analysis, PSE aligned the availability dates for mid-duration and long-duration storage based on the timing when each technology is expected to be sufficiently mature and scalable for consideration in the ISP.

Slide 17: For the capacity expansion modeling, are the prices for resource capital costs listed on the slide (vintage year 2025) for emerging technologies used as the price in the year listed as “first year available”? If so, why are the resources not instead modeled to be at a price further down the cost curve on the “first year available” year?

The capital cost values shown on Slide 17 are vintage-year 2025 input assumptions used as the starting cost for each emerging technology. In the capacity expansion model, those costs are applied when the resource first becomes available and then follow the applicable cost trajectory over the planning period. For emerging technologies, the first-year-available assumption is intended to reflect when the technology is expected to be sufficiently mature, commercially available and scalable for planning purposes; therefore, PSE does not assume an additional cost reduction before that first available year unless supported by the selected cost source. Nth-of-a-kind (NOAK) costs are especially difficult to model and predict, even compared with first-of-a-kind (FOAK) costs, because they depend on future deployment levels, supply-chain development, manufacturing scale, labor availability, financing conditions, permitting, interconnection and other market factors outside PSE’s control. For that reason, PSE does not rely solely on developer projections or assume that future costs will match optimistic long-term forecasts. PSE will continue to review updated market data, RFP results and feedback from interested parties as these assumptions are refined for the ISP.

Slide 23: What analysis is PSE hoping to gain from a sensitivity that includes unlimited batteries and LDES?

The unlimited battery sensitivity demonstrates how much storage would be needed to replace natural gas resources for resource adequacy. Based on feedback from interested parties, we were asked to look at a version that includes both short duration and long duration storage.

Slide 23: What are the fuel prices assumed for renewable natural gas in the reference scenario and across sensitivities? Has PSE, or does PSE plan to, run a sensitivity on renewable natural gas availability or prices? If not, why not?

Staff notes that fuel costs, and in particular, renewable natural gas fuel prices are likely a key assumption that determines the optimal portfolio. Staff requests that PSE clearly present their assumption on natural gas and renewable natural gas fuel costs to the RPAG and solicit feedback on fuel cost assumptions and sensitivities.

The renewable fuel prices were presented at the May 15, 2025 RPAG meeting. We reviewed several options that included renewable diesel, sustained aviation fuel (SAF), bio-based diesel, and methanol. PSE proposed to use the average of the fuel prices, but we received feedback to just use the bio-based diesel fuel price since that is the only fuel currently available that is CETA compliant. Therefore, the electric analysis does not include renewable natural gas. The cost of the tank and 240 hours of fuel per year is included in the cost of the peaker. The LCOEC for the renewable peaker presented at the May 2026 RPAG meeting includes all these costs.

Slide 24: How much wind in the reference case is identified as onshore versus offshore?

Offshore wind was given as an option but was not selected in the model. All the wind selected by the model is onshore.

Slide 25: For the “No-emerging tech + unlimited battery + LDES” sensitivity, what is meant by “Yes + exceeded input threshold”?

Batteries still exceeded the ELCC tranche boundaries.

Do the portfolio costs on slides 27 and 29 include fuel costs for operating the portfolio to meet forecasted energy and capacity needs? If not, please explain why not.

Yes, portfolio costs include fuel costs.

Gas Scenarios:

Slide 41: Staff is concerned that the reference scenario, Scenario 1, and Scenario 3 do not properly explore how gas customers react to rising rates, often referred to as the mid-transition risk. It does seem plausible that the scenarios look more like Scenarios 2 and 4 as opposed to how they are presented in the other scenarios.

Scenario 1 explicitly considers the interaction between gas and electric rates and the influence of those rates on customer decision-making over time. The analysis used planning-level projections of gas and electric rates throughout the study period to assess how customers are likely to respond when gas appliances reach end of life, including whether they choose to electrify or replace their existing gas equipment.

While higher gas rates can influence customer adoption decisions, the transition levels reflected in Scenarios 2, 3, and 4 would require additional policy mandates or other market drivers that are not currently in place. Therefore, Scenario 1 may be more representative of expected customer behavior with a general heat pump incentive, whereas Scenarios 2 through 4 assume progressively higher levels of electrification enabled by additional actions beyond current requirements.

Slide 48: Why are cumulative gas savings decreasing over time?

While cumulative savings typically increase over time, this chart reflects the modeled stock of persistent programmatic gas savings under each scenario. Under the electrification scenarios, gas end uses are progressively removed from the system, reducing both future gas conservation opportunities and portions of the existing gas conservation portfolio. As a result, the cumulative programmatic gas savings potential eventually declines as electrification outpaces new gas conservation acquisition.

**Katie Ware and Megan Larkin on behalf of Renewable Northwest and Climate Solutions,
September 2, 2026 via isp@pse.com**

I. INTRODUCTION

Renewable Northwest (“RNW”) and Climate Solutions appreciate Puget Sound Energy’s (“PSE” or “the Company”) continued engagement with stakeholders during development of its 2027 Integrated System Plan (“ISP”). With PSE now proceeding with Reference Case B as the starting point for further analysis, the focus of this feedback is on ensuring the remaining sensitivities meaningfully test the major risks and assumptions embedded in that case and provide sufficient information to inform the preferred portfolio. In particular, the August results reinforce the importance of testing alternatives to the approximately 5,000 MW of flex-fuel peakers selected in the Reference Case, more clearly representing the capacity contribution of storage and hybrid resources and ensuring that gas and electric system costs and risks are evaluated consistently.

II. FEEDBACK

A. PSE should distinguish higher-confidence near-term results from increasingly uncertain long-term results.

RNW and Climate Solutions recommend that PSE separately report resource additions, costs, emissions, and accredited capacity over approximately the first ten years of the planning horizon and over the longer-term period extending toward 2045 and 2050. The August materials frequently present cumulative 2050 results, even though uncertainty around technology availability, fuel markets, transmission development, load growth, and policy increases substantially over that period. This distinction is particularly useful in an ISP that must both evaluate a long-term planning horizon and produce a ten-year Clean Energy Action Plan (“CEAP”).

Our recommendation:

At minimum, PSE should provide intermediate results around 2035-36 showing cumulative resource additions, system costs, emissions, and accredited capacity under each major sensitivity. This would help identify which investments represent robust near-term actions across plausible futures and which depend primarily on assumptions about the 2040s.

Thank you for your feedback. PSE is summarizing volumes of analysis and data in RPAG meetings to provide as much information as possible within the time allowed. PSE’s analysis spans the entire 20-year planning period with the years 2035 and 2050 generally used for comparison purposes in RPAG meetings. This feedback prioritizing intermediate results is particularly helpful in thinking about how we frame the cost test and decision framework in the coming months and then how we present data in the Draft ISP Summary in December.

B. PSE should more aggressively optimize storage duration and hybrid resources before relying on new flex-fuel generation.

RNW and Climate Solutions remain concerned that PSE’s treatment and presentation of battery storage obscures whether the model is actually identifying the most cost-effective storage portfolio as penetration increases. PSE’s August materials report a single winter ELCC schedule for “short-

duration storage (Li-ion battery)” — 25%, 16%, and 10% across three tranches—without showing duration-specific ELCCs or the amount of each 2-, 4-, 6-, and 8-hour lithium ion configuration selected, either on a nameplate or accredited-capacity basis. As a result, stakeholders cannot determine whether PSE is allowing the model to transition among battery durations as shorter-duration storage saturates, or whether different battery configurations are effectively being evaluated in separate technology silos.

This distinction is important. Recent S&P Global analysis illustrates that continued additions of one battery duration can rapidly reduce its marginal ELCC, while incremental shifting toward longer-duration lithium-ion can preserve substantially more accredited capacity. In S&P’s Dominion example, an all-4-hour portfolio totaling 16 GW of ICAP provides only about 6.5 GW of UCAP by 2045, while a portfolio totaling the same 16 GW but consisting of 4-, 6-, and 8-hour batteries provides approximately 13 GW of UCAP.¹ S&P further finds that as 4-hour ELCC declines, longer-duration batteries can become less expensive on a \$/kW-UCAP basis even though they remain more expensive on a \$/kW-ICAP basis. S&P specifically describes the economically relevant transition as gradual: beginning with predominantly 4-hour resources and introducing increasing quantities of 6- and 8-hour storage as penetration grows and shorter duration ELCC declines.²

We realize Dominion is summer-peaking, while PSE’s reliability challenge is predominantly winter-driven. However, new Pacific Northwest-specific analysis by PowerGEM reaches the same directional conclusion. PowerGEM finds that storage ELCC declines with penetration across all durations, but that longer-duration storage consistently retains greater capacity value. Its baseline LOLE analysis, for example, finds approximately 49% ELCC for 4-hour storage versus 68% for 8-hour storage at 1,000 MW penetration, and approximately 22% versus 29% at 5,000 MW. When neighboring Western systems are modeled explicitly, those values increase meaningfully, with 5,000 MW of 4-hour storage receiving approximately 35% ELCC compared with 56% for 8-hour storage.³

These findings reinforce our persistent concern that PSE should not treat a declining ELCC for one storage configuration as evidence that “storage” broadly has saturated. Instead, PSE should demonstrate that the capacity-expansion model can endogenously move among 4-, 6-, and 8-hour lithium-ion configurations as their relative cost per dependable kW changes.

Our recommendations:

¹ ICAP refers to a resource’s installed or nameplate capacity, while UCAP refers to the portion of that capacity credited as dependable for reliability purposes after accounting for availability of ELCC. For example, a 100 MW resource with a 50% ELCC would have 100 MW ICAP and approximately 50 MW UCAP.

² Katherine Nelson, Dominion’s Storage Mandate Highlights Value of Long-Duration Capacity, S&P Global Market Intelligence (Aug. 12, 2026), *available at* <https://www.spglobal.com/market-intelligence/en/newsinsights/research/2026/08/dominions-storage-mandate-highlights-value-of-long-duration-capacity>. Also attached as Exhibit A.

³ PowerGEM, *PNW ELCC Sensitivity Analysis: Technical Report* (Aug. 2026) at 15, *available at* PNW ELCC Sensitivity Analysis.

- PSE should report, by duration and year, the amount of nameplate capacity selected, the corresponding accredited capacity, applicable marginal ELCC, capital cost, and cost per accredited kW.

PSE will submit completed work papers with the filed ISP in 2027. Although much of this information has been shared via RPAG presentations it is not yet available in a compiled, tabular format.

- PSE should explain whether the ELCC tranches are calculated independently by duration or whether deployment of one duration reduces the capacity credit available to other lithium-ion configurations.

The ELCC tranches for short and mid duration batteries saturate together. So, if tranche 1 is saturated with short duration storage, then both short and mid duration storage will move to tranche 2 for the next development of storage. Long-duration storage saturates independently.

Solar is grouped together for saturation, and wind is grouped into the zones Northwest and Rockies.

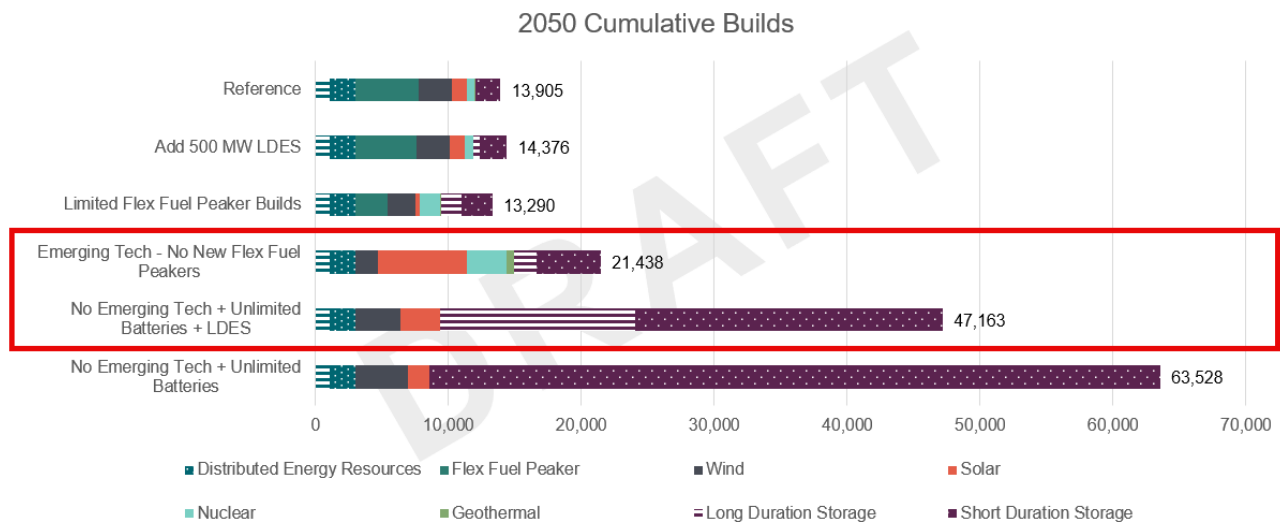
Hybrid resources should be presented with similar transparency. Though the August presentation is void of any mention of hybrid resources, PSE said during the meeting that the model did select hybrid resources but that their components were separated in the slide deck to avoid complexity. However, this aggregation removes information critical to evaluating the preferred portfolio. PSE should disclose the quantity and configuration of hybrid resources selected, their storage durations and accredited capacity, and how the model captures shared interconnection capacity, charging energy, and transmission utilization. PowerGEM similarly concludes that storage value is closely tied to access to charging energy and recommends pursuing hybrid resources where renewable energy can be better optimized through storage.⁴

Our recommendation:

- PSE should run a sensitivity that
 - Excludes new flex-fuel peakers;
 - Allows 4-, 6-, and 8-hour lithium-ion storage, renewable-storage hybrids, demand flexibility, and transmission solutions to compete using resource-specific costs and accreditation;
 - Progressively replaces the capacity contribution of existing gas before 2045 rather than creating an abrupt compliance-year cliff; and
 - Reports resource additions, nameplate capacity, accredited capacity, costs, and emissions separately for approximately the first and second decades of the planning horizon.

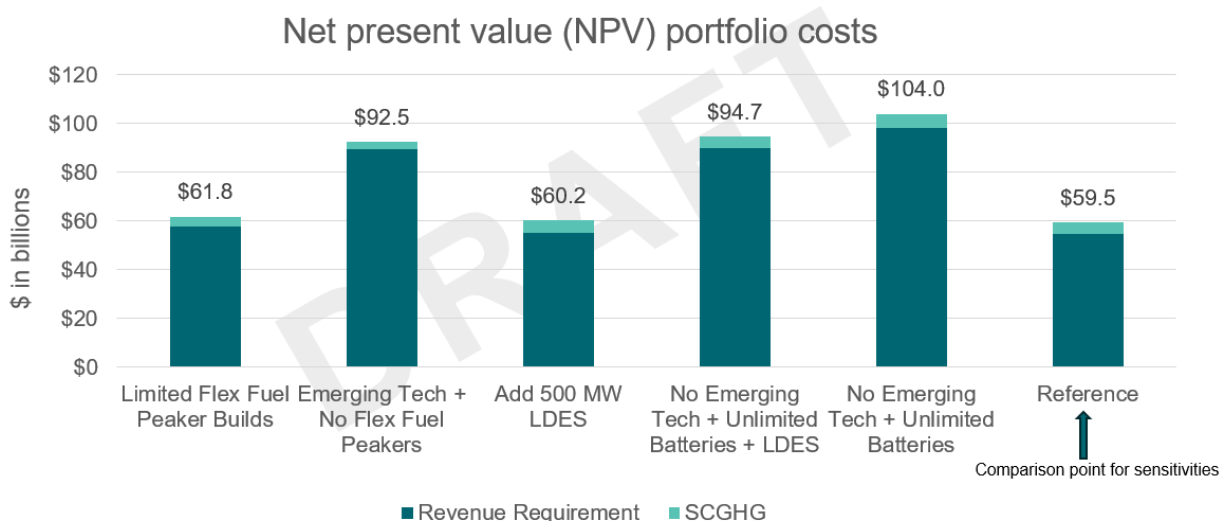
⁴ PowerGEM, *PNW ELCC Sensitivity Analysis*, at 27.

PSE evaluated two versions of this sensitivity (with and without emerging technology) and presented the results during the August 2026 RPAG meeting. The version with no emerging technology included short duration storage (2-6 hours) and the version with emerging technology



included short duration along with the mid duration storage (8-24 hours) and long duration storage (100 hours). The “Emerging Tech – No Flex Fuel peakers” sensitivity includes all battery options along with hybrids. The figure below is from that presentation and illustrates the builds for both sensitivity variations. Please note PSE models progressively replacing existing gas resources beginning in 2038 in all scenarios and sensitivities to avoid the “compliance-year cliff”.

NPV for each sensitivity is included in the figure below. Additional details, such as incremental builds in years other than 2050, will be included in the filed ISP and related work papers.



It is critical that PSE and stakeholders understand whether flex-fuel peakers remain economic when the uncertainties unique to that resource are treated explicitly rather than avoided.

The 2027 ISP models three different renewable plus storage (co-located) resource configurations. These options include –

- 1. 100 MW of wind coupled with 50MW of storage behind a 100 MW interconnection*
- 2. 100 MW of solar coupled with 50MW of storage behind a 100 MW interconnection*
- 3. 100 MW wind, 100 MW solar and 50 MW of storage with a 200 MW interconnection*

With market access for storage, and an interconnection larger than the sum of the individual ELCCs, the peak credit for co-located resources is simply the sum of its parts. This treatment also allows each of the components of the co-located resource to saturate appropriately with their standalone equivalents.

Hybrid vs Co-location:

Hybrid – This is where the battery can only charge from the renewable resource and does not have the interconnection to charge from the grid. This makes the ELCC significantly lower since the battery does not have the availability to recharge as needed.

Co-location – This is where the battery has the interconnection available to charge from the grid when the renewable resource is not producing energy, or the market is low cost.

We are modeling co-located resources in this ISP to capture the most benefits. For details on cost and capacity inputs see the table below.

Attribute	Units	Wind + Battery E WA	Solar + Battery E WA	Wind + Solar + Battery E WA
Capacity				
Net Capacity	MW	150	150	250
Effective Load Carrying Capability (ELCC)				
Tranche 1, Winter	%	Wind: 6%, Battery: 25%	Solar: 10%, Battery: 25%	Wind: 6%, Solar: 10%, Battery: 25%
Tranche 1, Summer	%	Wind: 5%, Battery: 52%	Solar: 27%, Battery: 52%	Wind: 5%, Solar: 27%, Battery: 52%
Tranche 2, Winter	%	Wind: 3%, Battery: 16%	Solar: 4%, Battery: 16%	Wind: 3%, Solar: 4%, Battery: 16%
Tranche 2, Summer	%	Wind: 2%, Battery: 39%	Solar: 12%, Battery: 39%	Wind: 2%, Solar: 12%, Battery: 39%
Tranche 3, Winter	%	Wind: 1%, Battery: 10%	Solar: 1%, Battery: 10%	Wind: 1%, Solar: 1%, Battery: 10%

Tranche 3, Summer	%	Wind: 1%, Battery: 10%	Solar: 4% Battery: 10%	Wind: 1%, Solar: 4%, Battery: 10%
Costs				
Capital				
Capital Cost	\$/kW	1,929	1,907	1,946
Interconnection Cost	\$/kW-yr	304	304	304

Note - Costs in 2020\$ and vintage year 2025. Interconnection costs apply only to generating resources.

C. PSE should test the full cost and risk of flex-fuel peakers.

Reference Case B selects more than 5,000 MW of flex-fuel peakers, yet PSE gives these resources a 91% winter ELCC across all penetrations tranches and has not demonstrated that the CETA-compliant fuel needed to support that capacity will be available, deliverable, and affordable at the scale assumed. PSE should apply the same scrutiny to peakers that it applies to storage.

PowerGEM's PNW analysis, for example, found new CT ELCC falling from roughly 89% to 72% and 54% under illustrative cold-weather outage sensitivities associated with fuel supply or weather risks.⁵ PSE should also update its peaker capital-cost assumptions using current market evidence⁶ and identify whether its modeled costs include the full infrastructure required to provide firm fuel—such as transportation, storage, compression, or other delivery infrastructure—rather than treating the generator and fuel system separately.

Our recommendation:

- PSE should run a flex-fuel risk sensitivity in which new peakers remain available, but their accreditation, capital cost, fuel cost and availability, infrastructure requirements, development lead times, and potential stranded-cost exposure are varied.

The sensitivity should seek to understand the impact of CETA-compliant fuel not materializing by 2045, the potential accelerated cost recovery or early retirement for these peakers, and replacement-capacity costs. An investment should not appear least-cost today because the model assumes a future compliant fuel market will emerge on schedule, only for customers to bear the cost if that assumption fails.

⁵ PowerGEM, *PNW ELCC Sensitivity Analysis*, at 16.

⁶ n *The New Reality of Power Generation: An Analysis of Increasing Gas Turbine Costs in the U.S.* (Sept. 2025), GridLab, Energy Futures Group, and Halcyon found that capital costs for new CT and CCGT projects have increased to around \$2,000/kW or more. The report also identifies growing turbine supply constraints and OEM reservation fees, including a \$25 million reservation fee paid by LG&E/KU to secure a GE Vernova manufacturing slot for a 2030 project. Available at https://gridlab.org/wpcontent/uploads/2025/09/GridLab_Gas-Turbine-Costs-Report-1.pdf.

The peaker costs were updated in the reference assumptions to reflect the highest point from the Black & Veatch technology assessment and is higher than the current market. The lead time was also updated to 5 years to reflect the current supply chain.

The decreased depreciation schedule was tested in the “No Emerging Technology” sensitivity. Peakers were allowed in the early years but were fully depreciated and retired by the end of 2044. Even with the shortened depreciation, peakers were still chosen to meet peak requirements.

D. PSE should improve accounting and transparency for gas-system costs under the electrification scenarios.

The August presentation raises an additional issue on the gas side of the ISP. PSE states that in Scenarios 2 through 4, gas supply resources become unused as demand declines, but that “gas portfolio system costs do not include costs for unused gas supply side assets.” Before these scenarios are used to compare the costs of different decarbonization pathways, PSE should explain precisely what costs are excluded and why they disappear when an asset or contract becomes unused.

PSE should distinguish costs that are truly avoidable from residual contractual or asset costs that customers may continue to bear, including fixed charges, minimum-volume or take-or-pay commitments, contract termination costs, remaining book value, and retirement or decommissioning costs. This is particularly relevant to PSE’s modeled renewal of Plymouth LNG in 2031.⁷ PSE should disclose the assumed renewal term, capacity, fixed cost, and termination or residual-cost obligations, and explain how those costs are treated in scenarios where LNG use later declines substantially or to zero.

Thank you for raising this issue. We agree that a clearer explanation of what is and is not included in the gas portfolio system costs is warranted, particularly as these scenarios are used to compare decarbonization pathways.

To clarify, the gas portfolio system costs in the current ISP include operating costs, supply costs, and contracted capacity costs associated with the gas portfolio, but do not include stranded costs associated with owned gas supply assets (e.g., remaining net book value, continued fixed O&M on underutilized assets) or decommissioning/asset retirement costs for assets that may be retired as gas demand declines.

This reflects a limitation of the current ISP methodology rather than a judgment that these costs are immaterial. The tool as built was designed to compare portfolio operating costs across scenarios and was not designed to calculate stranded-asset or decommissioning costs, which require asset-specific engineering, remaining-life, and accounting analysis that has not yet been developed for gas supply-side assets. We recognize that omitting these costs may understate total system costs

⁷ PSE August RPAG presentation, slides 58-61.

in scenarios where gas load and associated asset utilization decline substantially. We agree these are important cost considerations and an area for improvement in future ISPs.

Finally, RNW and Climate Solutions appreciate PSE's commitment during the August meeting to provide concrete examples of the projects included in the "customer requested and public projects," "transmission and distribution system reliability and resiliency," and "customer and public safety" categories.⁸ PSE should also identify the funding source for representative projects, particularly because the presentation states that customer-requested work is typically customer funded, and explain which investments remain subject to non-pipeline alternative review. This would allow stakeholders to distinguish the overall gas-system investment from costs actually borne by general ratepayers.

All the costs represented were the capital additions that go into rate base.

Customer and Public Safety

Customer and Public Safety investments include a mix of unplanned work, planned work where the need is known but the specific location is not known in advance, and planned work with known locations. Examples of unplanned work include immediate safety-related activities such as response to gas leaks, encroachments, and emergency repairs. Examples of planned work with locations identified through field activities include replacement of shallow mains or other integrity-related conditions discovered through inspections and ongoing system operations. Examples of planned work with known locations include compliance- and safety-driven programs such as Older Vintage PE Pipe (DuPont Aldyl-A) replacement and TSA-required Remote Terminal Unit (RTU) replacements.

These investments are undertaken to support customer, employee, and public safety, maintain system integrity, reduce methane emissions, and comply with federal and state safety requirements. To the extent work is planned, it is evaluated through PSE's NPA framework. Emergent and emergency work is performed to address immediate safety, reliability, or compliance needs and is not generally suitable for NPA evaluation.

Customer-Requested and Public Improvement Projects

Customer-Requested and Public Improvement Projects are driven by requests or requirements originating outside of PSE and are generally location-specific once initiated.

Customer-requested projects arise in response to requests for new or modified service from residential, commercial, multifamily, and development customers. These investments are undertaken pursuant to statutory and tariff obligations and include activities such as new service connections, line extensions, service upgrades, and facility relocations. Once a qualifying request is made, PSE is obligated to provide service at the requested location subject to applicable tariff terms. Customer-requested work is often funded in part by the requesting customer through

⁸ PSE August RPAG presentation, slides 75-77.

Commission-approved tariff provisions. The investment values presented in the framework reflect only the portion of project costs borne by PSE and do not include customer-funded contributions.

Public Improvement Projects are undertaken pursuant to municipal franchise agreements and governmental directives that require PSE to relocate or modify facilities to accommodate public works projects such as road widening, grade changes, and other infrastructure improvements. While these projects are not discretionary once requested by the jurisdiction, PSE routinely collaborates with the sponsoring agency to identify opportunities to minimize facility impacts, reduce relocation requirements, and avoid unnecessary infrastructure replacement. In practice, this collaborative approach serves a similar purpose to an NPA by seeking the lowest reasonable cost solution that satisfies the needs of the underlying project while minimizing impacts to customers.

Because Customer-Requested and Public Improvement Projects are driven by customer obligations, tariff requirements, franchise agreements, or governmental requests at a defined location, they differ from discretionary capacity-planning investments. As a result, traditional NPA screening is generally not applicable to customer-requested work. For Public Improvement Projects, however, PSE routinely evaluates alternatives with the sponsoring jurisdiction to minimize infrastructure investment while still meeting the project's objectives.

Reliability and Resiliency

Reliability and Resiliency investments are designed to mitigate service reliability and operational risks and ensure the natural gas system can continue to provide safe and reliable service under a variety of operating conditions. Representative projects include reinforcement of high- and intermediate-pressure delivery system components, system pressure uprates, odorization upgrades, and procurement of Cold Weather Action (CWA) equipment used for manual field interventions during peak load conditions to sustain reliable system operations.

Unlike emergency response activities or customer-driven investments, Reliability and Resiliency projects are generally planned investments intended to maintain system performance, address operational constraints, improve system flexibility, and reduce the likelihood or consequences of service interruptions. As such, these projects are generally evaluated through PSE's non-pipeline alternatives framework to determine whether a non-pipeline solution can meet the identified need at the lowest reasonable cost while maintaining reliability and operational requirements.

However, some reliability and resiliency investments may also be driven by specific compliance, safety, or operational requirements that limit the availability of non-pipeline alternatives. In those circumstances, the applicability of an NPA is assessed based on the nature of the underlying need and whether a non-pipeline solution can reasonably satisfy the project's objectives.

III. CONCLUSION

RNW and Climate Solutions thank PSE for its consideration of this feedback. We look forward to continued engagement in the RPAG process toward development of PSE's 2027 ISP.

RNW also provided [this article](#)⁹ with their feedback.

Unanswered RPAG member questions from the meeting:

Is there a realistic scenario where enough RNG is available to meet Scenario 2 and Scenario 4?

The assumptions for Scenarios 2 and 4 drive demand on the natural gas system to near zero meaning there PSE does not assume there will be enough renewable natural gas available at a reasonable cost to maintain today's gas system under Scenarios 2 and 4. Those scenarios are meant to test futures with much lower gas use because many customers electrify their homes and businesses. In that kind of future, renewable natural gas could play a limited role for remaining hard-to-electrify uses or reliability needs, but it is not assumed to be available at the scale needed to serve broad gas-system demand. Because supply, delivery and cost are uncertain, PSE continues to treat renewable natural gas as a limited resource rather than the primary decarbonization strategy for those scenarios.

2. Public feedback

Don Marsh on behalf of the Washington Clean Energy Coalition, August 24, 2026 via isp@pse.com

Slide numbers given without a date refer to the August 25, 2026 RPAG presentation. Earlier presentations are identified by month and year.

For the 2027 ISP Reference Case, PSE has used various inputs with values at or beyond the pessimistic edge of published reports. PSE erroneously removed a federal tax benefit for eligible resources. PSE also handicapped three technologies with availability dates that lag what is already being financed and built today.

Each of these choices raises the modeled cost of clean and storage resources compared to gas-fired capacity. Reference Case B builds 5,042 MW of flex-fuel peakers by 2050 along with 2,090 MW of storage, 300 MW of nuclear and 100 MW of geothermal (May 2026, slide 30). Slide 24 calls the reference case “our starting point for further analysis,” so errors will affect every sensitivity. PSE shows projected gas costs as a curve across the planning period, but gives other resources only point estimates at a single vintage year, with no annual cost trajectory. The August 25, 2026 presentation answers part of this: a numeric ELCC table (slide 18), a technology-readiness framework (slides 14–16), and ten emerging-technology sensitivities including geothermal at \$6,500/kW (slide 23). We appreciate this updated information.

1. Tax credit assumptions appear to be incorrect.

⁹ Dominion's storage mandate highlights value of long-duration capacity; <https://www.spglobal.com/market-intelligence/en/news-insights/research/2026/08/dominions-storage-mandate-highlights-value-of-long-duration-capacity>

May 2026 slide 76 assumes “Removal of previous tax credits from the Inflation Reduction Act (both PTC and ITC)” and “This materially increases resource costs.” Public Law 119-21 does not remove both credits from all technologies. Storage, geothermal, nuclear and hydro are not subject to the wind and solar phase-out. They remain on the technology-neutral §45Y and §48E credits at 100% for construction starts through December 31, 2033, 75% in 2034, and 50% in 2035. Wind and solar that began construction on or before July 4, 2026 retain the prior regime and the four-year continuity safe harbor, giving a placed-in-service deadline of December 31, 2030. Also the 5% cost safe harbor, eliminated by IRS Notice 2025-42, was restored when that notice was vacated on June 6, 2026.

PSE’s reference case appears to remove tax credits from 4-hour batteries and enhanced geothermal, both of which retain the full credit. The August 25 deck does not mention the ITC, the PTC or P.L. 119-21, and no tax-credit sensitivity appears among the ten modeled.

Request: Confirm whether the reference case reflects the technology-specific treatment in P.L. 119-21 and correct it if it does not, or state the legal basis for removing the credits from each technology.

Under the One Big Beautiful Bill Act (OBBA), wind and solar ITC/PTC credits generally expire earlier than the long-term planning period evaluated in the ISP; therefore, PSE did not include those credits in the long-term resource assumptions. For emerging technologies such as nuclear and geothermal, the full credit is available only if projects meet start-of-construction requirements by 2033, with completion generally required within four years, followed by a phase-down through 2035. Given the longer lead time assumed for nuclear, which is modeled with a 2040 first online year, PSE does not assume nuclear would qualify. Geothermal may have greater potential to meet the tax credit timing requirements if available by 2035; however, PSE separately tested a lower geothermal capital cost that reflects current cost estimates, and that sensitivity already maximized geothermal selection without assuming tax credits.

The credit may also apply to battery energy storage systems (BESS), but project eligibility depends on several factors, including restrictions related to prohibited foreign entities and domestic content requirements. These requirements create uncertainty about whether projects would qualify and how much cost benefit would ultimately be realized. Because of this uncertainty, and the potential for future legislative or implementation changes, PSE did not include tax credits in the long-term reference case assumptions but will continue to review current law, guidance, market data and feedback from interested parties as assumptions are refined.

2. What supports geothermal cost and availability assumptions?

PSE’s new lower-cost geothermal sensitivity (slide 23) sets capital cost at \$6,500/kW — inside Lazard’s July 2026 range of \$5,135–6,635/kW — and reports a \$2.1B lower NPV, roughly 4% below the reference case. We appreciate the run, and the result confirms the assumption is consequential. Two problems remain. First, the record now contains three different costs for one resource:

\$11,057/kW (May 2025), \$11,893/kW (slide 17), and \$10,525/kW, which slide 23 identifies as the base the sensitivity moved from. Which figure does the reference case use?

Second, the 2035 date is unchanged. Slide 15 rates enhanced geothermal TRL 7 — “working pilots in the field, no commercial fleets yet.” Fervo Energy has roughly 500 MW under construction at Cape Station, a binding PPA backlog of about 658 MW, and expects first power to the grid within months. Slide 15 defines TRL 8 as “demonstrated at scale, with limited commercial fleets.” Because the first-year-available date follows from the TRL, this tells the model that geothermal can’t be selected before 2035. On the other hand, PSE’s 2026 RFP was open to any CETA-compliant resource online by January 1, 2032 and listed enhanced geothermal under “Dispatchable Capacity.” PSE should be consistent.

Request: Reconcile the three base capital costs and state which the reference case uses. Explain why enhanced geothermal is rated TRL 7 rather than TRL 8 under slide 15’s own definitions. State how many enhanced geothermal and long-duration storage bids were received in the 2026 RFP.

The May 15, 2025 RPAG presentation included draft costs that did not include the EIA adder. The National Lab of the Rockies (NRL), formerly NREL, annual technology baseline (ATB) costs is a national average and is not intended to be used for regional purposes; in order to extrapolate the data for a specific region you will need to include a regional adder. NRL recommends using the Energy Information Administration (EIA) Annual Energy Outlook (AEO) regional adder to get the regional costs for the PNW. The updated costs now include the EIA AEO regional adder. The cost listed in the most recent slide is the current draft cost used for the 2027 ISP.

PSE is modeling geothermal in the same manner as any other available resource. But given the current information of costs for geothermal, PSE ran a sensitivity with lower geothermal costs. This was discussed at the August 2026 RPAG.

Pursuant to Washington Administrative Code 480-107-035(5), within 30 days after the close of the bidding period, the utility must post on its public website a summary of each bid the utility has received. Where use of confidential data prohibits the utility from identifying specifics of a bid, a generic but complete description is sufficient. For the 2026 Utility-Scale RFP, this required report is available on our website and contains information regarding the technology type of bids received in the 2026 Utility-Scale RFP.

3. How current is the cost data?

May 2026 slide 88 places BESS at \$1,136/kW-yr of effective capacity compared to \$526/kW-yr for a natural gas peaker and \$383/kW-yr for a renewable peaker. Batteries face a triple threat: a capital cost above the current published range, a rescinded investment tax credit the statute actually preserves, and a very low winter capacity credit (Question 5). If any of these assumptions were changed, batteries would be a more attractive option.

Technology	PSE, as published (2020\$/kW)	Current benchmark, as published (\$/kW)	Difference
4-hour Li-ion battery	1,844	1,581 EIA AEO2026 NWPP (2025\$) 1,336 NREL, Jun. 2025 (2024\$)	at least +17%
Enhanced geothermal	11,893	5,135–6,635 Lazard v19 (2026\$) ~7,000 Fervo, actual	at least +79%
Utility-scale solar PV	1,938	1,452 EIA AEO2026 NWPP (2025\$) 1,610 LBNL 2024 observed (2024\$)	at least +20%

PSE relies on the 2024 NREL ATB for the cost basis of various technologies. But costs have moved sharply since June 2024. For example, in June 2025 NREL found four-hour lithium-ion storage at \$1,336/kW, declining roughly a third from the \$2,160/kW ATB value PSE cites on May 2025 slide 50. Between its January 2024 study and AEO2026, EIA raised frame combustion turbine cost from \$836/kW to \$1,158/kW and combined cycle from \$868/kW to \$1,032/kW. Given these inputs, it's little wonder that PSE's Reference Cases preferred cheap gas to expensive batteries.

Request: State the source and collection date of the cost data behind each figure on May 2026 slide 81, and confirm whether costs were refreshed using bids received in the 2026 Voluntary Utility-Scale RFP, which closed April 10, 2026.

The source data for the resource cost assumptions was presented at the May 15, 2025 RPAG meeting and reflected the best available planning inputs at the time the draft 2027 ISP assumptions were developed.

4. Why are different cost curves used for utility-scale resources and DERs?

The table below shows resource costs from May 2025 slides 50–52, except for the final row (May 2026, slide 103). These are in 2022 dollars; the Question 3 figures restate the same resources in 2020 dollars, which is why solar appears as \$2,169 here and \$1,938 there.

Resource	ATB curve PSE cites	2024 ATB \$/kW	Draft 2027 ISP \$/kW	Difference
Utility-scale solar PV	Conservative	1,541	2,169	+41%
Onshore wind	Conservative	1,633	1,790	+10%
4-hour Li-ion storage	Conservative	2,160	2,079	-4%
Solar + storage hybrid	Conservative	2,569	2,139	-17%
Gas peaker	Conservative	1,319	1,729	+31%

Resource	ATB curve PSE cites	2024 ATB \$/kW	Draft 2027 ISP \$/kW	Difference
Combined cycle	Conservative	1,730	1,730	none
100-hour iron-air storage	Conservative (stated)	none shown	2,389	—
Customer-sited solar and storage	Moderate	—	—	—

May 2025 slide 48 states: “All 2024 NREL ATB Costs are on the conservative cost curve,” and the October 1, 2025 modeling memo repeats it. However, for distributed energy resources (e.g., customer-sited solar and battery storage), PSE instead chose the “NREL 2024 Annual Technology Baseline (ATB) (moderate)” (May 2026, slide 103). These different curves for utility vs. customer solar+storage make us wonder if PSE is using a conservative curve as a procurement hedge. If so, the unhedged case should be run as a sensitivity, as Commission Staff requested. But PSE replied: “No, PSE is not planning to run alternative resource cost sensitivities. ...we anticipate that other elements play a larger role in influencing the resource selection.” Rather than asking us to trust PSE’s instincts, the model should test this hypothesis.

The difference column in the table above shows PSE diverging from ATB costs, both higher and lower, with little explanation. PSE’s decision to use ATB’s conservative curve for every utility-scale technology might sound like equitable caution, but in practice it is a significant departure from historical trends. For example, the conservative curve projects a relatively meager cost decline for utility-scale four-hour batteries by 2035. However, NREL’s own base-year cost fell from \$482/kWh to \$334/kWh between its 2023 storage update, on which the 2024 ATB relies, and its June 2025 update. That is a 31% decline in two years, much larger than the 18% decline over 13 years (2022–2035) projected by the conservative curve.

For gas, it’s a different story. The conservative gas curve assumes only “minor reductions in capital costs through 2050,” yet gas costs rose 18–39% as published in the past two years (see Question 3).

The conservative curve is therefore too pessimistic for storage and too optimistic for gas, and all sensitivities will produce erroneous results if these curves remain uncorrected in the Reference Case.

Request: Justify the conservative curve technology by technology against observed 2022–2026 costs, rather than as a blanket setting. Run the moderate curve as a sensitivity and report the portfolio delta, as Commission Staff requested. Explain the utility-scale / DER asymmetry.

PSE used the conservative cost curve for utility-scale resources because recent market conditions have shown that project costs can be higher than national benchmark estimates once regional factors are considered. These regional factors can include supply-chain constraints, interconnection

costs, transmission availability, labor costs, financing costs, permitting timelines and project-specific development risks. The conservative curve is not intended to favor gas resources or disadvantage clean resources; it is intended to avoid understating costs in a long-term planning model where many projects would not be built for several years.

Because published cost sources can use different dollar years, scopes, regions and included cost categories, PSE does not rely on a single benchmark comparison to revise assumptions. Instead, PSE applies a consistent framework across resource types and tests selected cost changes through sensitivities where they are most likely to affect portfolio results.

The distributed energy resource assumptions are developed separately because customer-sited solar and storage have different cost drivers than utility-scale resources, including customer adoption, retail incentives, program delivery costs, installation practices and customer economics. For that reason, the DER cost pathway is not directly comparable to the utility-scale cost curve. PSE will continue to review updated public benchmarks, RFP market information and feedback from interested parties as cost assumptions are refined for the ISP and future planning cycles.

5. How are ELCC values calculated?

Slide 18 publishes ELCC by technology across three penetration tranches. This is helpful, but tranche boundaries are not defined in MW, so a reader cannot tell which value applies to a given build. The note states winter values; summer values are not shown. The table does not say whether values are marginal or average. RFP Table 3 gives 4-hour storage 16% in winter, matching slide 18's Tranche 2. Does that reconcile the 54% marginal ELCC cited for PSE's existing 437 MW fleet in the September 30, 2025 study?

On May 28, 2026, Renewable Northwest noted E3's regional study found average ELCCs of 63–77% for 100-hour iron-air; slide 18 now shows 85%, 85% and 13% across tranches. How do these relate to the E3 figures?

Request: Define the slide 18 tranche boundaries in MW, publish the summer values, state whether the values are marginal or average, and confirm whether RFP Table 3's 16% is the Tranche 2 figure.

The September 30, 2025 RPAG presentation includes the tranche boundaries in MW and the summer ELCC values. The values shown on slide 18 of the August 2026 presentation are marginal ELCC values by resource type and tranche, meaning they represent the capacity contribution of the next block of resource additions within each tranche rather than the average value across all existing and new resources. The 16% winter value for 4-hour storage in RFP Table 3 aligns with the Tranche 2 winter value shown in the August materials.

As additional storage is added, the incremental capacity value of the next storage block declines because storage resources increasingly serve the same peak and reliability hours. That is why the tranche values decline as saturation of similar energy limited resources increases. The resource

adequacy study is a PSE-specific study and is not a direct one-for-one comparison to regional average ELCC values from other studies or utilities, which includes different systems, weather years, saturation levels, reliability needs, and modeling assumptions.

6. What is included in the May 2026 capital costs?

May 2025 slide 48 states that interconnection costs and lease fees are excluded and “will be added later.” May 2026 slide 31 states portfolio costs include “electric generation, interconnection and upgrade costs, associated BPA transmission costs.” In the May 28, 2026 feedback report PSE stated: “We are in line with Lazard’s EPC costs; the added costs are coming from transmission and integration costs.” However, Lazard v19 puts utility-scale solar capital cost at \$1,250–1,850/kW, while May 2026 slide 81 prices solar at \$1,938/kW. That exceeds Lazard’s range as printed, before any dollar-year adjustment.

Request: Publish a cost bridge slide showing EPC, owner’s costs, interconnection, transmission and integration as separate line items for each technology, in a normalized dollar year.

Answering slide 32: we ask for corrected tax credits in the Reference Case and all sensitivities. Additional sensitivities should study a current-cost case for lithium-ion storage, and a more realistic moderate-curve case for technologies that have demonstrated faster cost reductions in recent years. Separately, slides 27–29 give the reference case NPV as \$59.5B while slide 30 refers to \$55.0B; please confirm which is the comparison point. We hope PSE will provide updated costs, fairer comparisons, improved transparency, and a portfolio we can fully understand.

PSE is sharing information in draft form as it becomes available. Additional details will be included in the filed ISP as required by Commission rule and in support of the state defined ISP review and approval process.

Don Marsh on behalf of the Washington Clean Energy Coalition, August 25, 2026 via isp@pse.com

Since our June 21 memo, PSE has published two sets of draft results that provide more information: the July 28 RPAG presentation (the Electrification Potential Assessment and draft scenario demand forecasts) and the August 25 RPAG presentation (draft sensitivity results, including published capacity credits and a lower-cost geothermal case). This addendum updates our memo where figures have changed and notes what remains untested. Otherwise, our June memo is unchanged.

1. PSE’s new results support geothermal and LDES

- **Multi-day storage is a good solution.** Allowing long-duration storage into PSE’s “no emerging technology” case cut its cost from \$104.0 billion to \$94.7 billion and displaced 33,650 MW of four-hour batteries (Aug. 25, slides 26–30). This confirms our criticism of Reference A: its failure was a design problem, not evidence against clean portfolios.

- **Cheaper geothermal saves money.** When enhanced geothermal is priced at \$6,500/kW instead of \$10,525/kW, portfolio cost is reduced by \$2.1 billion, roughly 4% below the reference case (slides 23 and 29–30). Our memo priced geothermal at PSE’s original \$11,893/kW and still reached cost parity. At PSE’s sensitivity price, it becomes clear the clean portfolio is cheaper than Reference B.

- **The lower geothermal price is approximately current tax law.** The 2025 federal budget law repealed clean-energy credits for wind and solar, but the technology-neutral credits survive for storage, geothermal, and nuclear: 100% for projects beginning construction by 2033, then 75% (2034), 50% (2035), and zero after. PSE’s \$6,500/kW sensitivity is close to its \$10,525 base cost net of the statutory 30% investment tax credit plus one 10% bonus. The \$2.1 billion saving is not industry optimism; it is roughly what current law delivers, provided construction begins by 2033.

- **Halving the peakers costs almost nothing.** Replacing half the flex-fuel peakers (2,500 MW) with enhanced geothermal (slide 29) costs less than 2% of the total cost of Reference B.

- **Geothermal is firmer than we assumed.** PSE’s published winter capacity credits (slide 18) rate enhanced geothermal at 96%, above the conservative 90% our tables use. It is equivalent to a nuclear SMR at 97%. Our memo’s preference for geothermal over SMR is justified on cost, schedule, and effective capacity (not to mention safety and environmental risks).

2. Revised figures in our memo to track PSE’s updates

- **Restated PSE figures.** PSE’s August results restate the reference case at \$55.0 billion in revenue requirement (\$59.5 billion with the social cost of greenhouse gases, vs. \$55.4 billion in May) and reference gas supply at \$23.4 billion (vs. \$29.2 billion, after excluding CCA consigned allowances). Relative comparisons in the memo are unaffected; we will rebuild its combined-cost table when PSE publishes combined gas-and-electric scenario costs in September.

- **Line losses.** PSE corrected its electric line-loss factor from 7.58% to 5%, lowering loads and peaks 2.7% in every year (July 28, slide 51). That alone closes roughly a third of the memo’s ~300 MW gap at 2035, the only year our planning case fell below 100% of the no-gas need.

- **Iron-air capacity credit.** PSE credits iron-air at 85% for the first two tranches (13% thereafter), below the 95% winter availability our tables assume. At 85%, our 2035 iron-air capacity is roughly 300 MW rather than 335 MW — a difference well within the 800 MW contingency reserve. PSE’s tranche sizes remain undisclosed (memo Request 3).

- **Tax credits.** Our memo described the portfolio as priced “without expired subsidies.” That is correct for wind and solar but understates our case for storage and geothermal, whose credits survive. A 30% credit on the tranches our portfolio builds before the phase-down — roughly 350 MW of iron-air, 600 MW of substation storage, and 100 MW of geothermal — is worth about \$0.9–1.2 billion, with domestic-content and energy-community bonuses that could raise it further. Reference B’s peakers qualify for nothing, and its 2040 SMR falls into the phase-down years. The net effect favors the clean portfolio by roughly \$0.5–1

billion beyond the parity shown in the memo. To save ratepayers money, it is important to get in the queue for iron-air batteries and geothermal plants soon: data centers and other utilities are competing for the same production capacity, and the full credit requires construction to begin by 2033.

3. PSE has begun the analysis the memo requested

- **High-electrification demand is now modeled.** Scenario S2 (building electrification only) roughly doubles the 2050 winter peak (10,748 MW vs. 5,615 MW) and takes residential and commercial gas customers to near zero by 2041–42. PSE’s assessment models 4–5 kW of added winter peak per residential customer at 23°F — matching our high case. Our lower mid case reduces demand through weatherization and load flexibility, which PSE’s forecast does not fully credit.

- **Our gas-side economics improve.** Under S2/S4, gas supply costs fall from \$23 billion to \$9 billion and gas-system emissions approach zero by 2050. PSE notes these results “do not reflect the costs and benefits associated with retirement of the gas system.” Our memo requests exactly this analysis (Requests 6 and 9), which we hope to see in the September RPAG meeting.

4. A caution on PSE’s “no-peaker” sensitivities

PSE’s runs that exclude flex-fuel peakers cost \$88.6–92.5 billion. However, those runs exclude nearly every resource in our portfolio — no vehicle-to-grid, no expanded demand response, no behind-the-meter or substation storage, no winter-weighted Montana wind. As a result, storage credits saturate quickly, and the model overbuilds the few resources it is allowed to see. The sensitivities test a stripped-down portfolio no one is proposing. The correct test remains memo Request 1: optimize the full, diversified portfolio as a reference-quality case.

[Thank you for your feedback. Please see our response to your request on page 12 of the July 28, 2026 RPAG meeting feedback report.](#)

Don Marsh on behalf of the Washington Clean Energy Coalition, August 25, 2026 via public comment opportunity

I'm Don Marsh, chair of the Washington Clean Energy Coalition. I have two objections today. First, slide 24 calls reference case B our starting point for further analysis. That is precisely our concern. Every sensitivity PSE runs is a variation on a gas-heavy portfolio. Change one assumption at a time, and you learn how that portfolio responds. You do not discover a different one. It is like designing an electric car by starting with a gas car and swapping one part at a time. You would conclude an EV is too awkward and expensive to build, and you would be wrong. Your own results today make this point. Slide 26 shows that when peakers are limited, long duration storage gets selected and total builds go down. Your geothermal sensitivity, reduced portfolio NPV by \$2.1 billion. But no sensitivity shows what these technologies might do in tandem with other clean solutions and high electrification. Slide 31 asks whether you are missing a combination critical to a preferred portfolio. Yes, the missing case is a clean sheet portfolio built around iron air storage,

geothermal virtual power plants and full electrification of the gas system. We want that portfolio to be evaluated on its own terms, not as a deviation from reference case B.

On June 19, the coalition submitted a 20-page analysis indicating such a portfolio may be achievable at costs similar to our below PSE's reference case. We asked explicitly that it be included in the feedback report. So that brings me to the second problem. PSE told us our analysis would be valuable for ISP modeling. It then appeared nowhere in the feedback report for over two months. When we asked why, PSE said it would be premature to comment on our document's accuracy, validity, or reasonableness. We never asked PSE to endorse our analysis. We asked that it be recorded. If substantive feedback can be left out of the record until PSE is ready to evaluate it, the feedback process is broken. Members of our coalition have served on PSE advisory groups. For more than 10 years, we are not raising this casually. So three requests. First, acknowledge our June 19th analysis in the feedback report and address the nine questions we posed on pages 16 and 17.

PSE's responses to Mr. Marsh's feedback are in the [July 28, 2026 RPAG feedback report](#).

Second, state whether PSE will model at least one clean sheet portfolio rather than only sensitivities on reference case B. Third, yesterday we submitted a detailed set of questions on cost, capacity, and availability assumptions. Publish these questions and your responses in the feedback report for this meeting. If necessary, we will raise our questions in the Commission's review of the ISP, but we would much rather resolve them here. Thank you very much.

Mark R, August 25, 2026 via public comment opportunity

A concern I'm representing myself, not a not an agency or group. It looks like for the gas peakers and the draft scenarios, I'm wondering if it's possible to identify the health and environmental cost of those resources rather than just their direct and capital costs. And I wonder if you could somehow identify an actual cost per dollar or cost per megawatt in terms of social and the added cost for gas peakers and the draft scenarios. I'm also concerned that it looks like it takes you at least 9 years for a new technology to become available, it looks like you're walking into the future, looking backward, and you're looking backward a long ways, and aren't able to utilize things that we need now.

Thank you for your comments. The social cost of greenhouse gases is included in the total portfolio cost and the evaluation of new resources.