Resource Planning Advisory Group feedback report Meeting details

- Tuesday, June 24, 2025, 10:00 a.m. 1:00 p.m.
- Virtual webinar hosted by PSE and facilitated by Triangle Associates
- Links to:
 - Presentation
 - 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 Integrated System Plan website. PSE responses are shown in teal italics.

Note: PSE aims to provide clarity in responses but subsequent follow-up may be required at times. Please direct any follow-up clarifications to isp@pse.com.

RPAG member feedback

1. JP Caravallo on behalf of Lawrence Berkeley National Laboratory, June 18, 2025 via isp@pse.com

Electric modeling assumptions:

How are you ensuring that resources assigned to a transmission region are the most cost-effective version of that resource in the service territory?

PSE will use one cost for each resource type (e.g., wind, solar); the transmission zones costs will vary based on interconnection and wheeling costs for those specific areas.

PSE is utilizing a combination of costs for resources including the NREL ATB, Black & Veatch Technology Assessment, and information from PSE's most recent procurement processes. The various resources and their cost sources are identified in the <u>materials</u> from the <u>May</u> 15, 2025 RPAG meeting.

In terms of emerging resources, I think the key question is how different is the system built out in 2050 when those resources become available in 2030-40? In particular, how would transmission – arguably the slowest and most capital intensive resource – be built differently if those technologies became available? I think this will show how able PSE will be to just switch out certain traditional resources for these new resources when/if they become commercially available, as their uncertainty makes it ineffective to "plan" for them. I would recommend a scenario based approach rather than trying to come up with a cost adder for the emerging resource. Given the values, you could run a scenario with the B&V values and the NREL values and check how the resource choices change by 2035-2040.

The reference case will be set up with commercially available resources. The sensitivities will evaluate the impact of various emerging resources compared to the reference case to see how the portfolio builds might change if the resources become available.

The volume of scenarios given the magnitude of the modeling required for an ISP can become infeasible rather quickly. To alleviate this, if we are looking at emerging resources that may come online by 2037, we may need to consider sensitivities around specific emerging resources. If we are looking at resources after that timeframe, it is outside of the long-haul transmission horizon and therefore will not have an impact on our near-term actions. The analysis of those emerging resources can be reevaluated in the next ISP.

An idea that we used in the past to represent "uncertain" resources was to use a higher capital cost to reflect how private investors would assess a riskier asset. It's not trivial to define that cost, but there may be some evidence in financing rates for early solar and wind projects from a couple of decades ago, normalized by economic activity, prevailing interest rate, etc.

Recommend against using adders for tariffs, given how uncertain they are.

I do not believe short and mid-duration storage requires any uncertainty adder, there are GWs of the technology deployed already. LD storage should be simulated carefully because it induces substantial changes in the system outcomes. I would recommend limiting the deployment levels rather than letting the capacity expansion models choose whatever amount it wants to deploy from a certain year.

Thank you for your feedback.

On the thermal resource capital costs, are there recent acquisitions by neighboring utilities that can be used as a benchmark, or are those typically confidential?

Acquisition costs are confidential.

What would justify uncertainty adders to mature renewable resources such as wind and solar? In particular, what explains the higher cost used for utility scale solar in PSE's ISP compared to the ATB?

An uncertainty adder for a mature resource can represent a construction contingency for costs or the risks that resources are higher cost than expected.

PSE is utilizing a combination of costs for resources including the NREL ATB, Black & Veatch Technology Assessment, and information from PSE's most recent procurement processes. The various resources and their cost sources are identified in the <u>materials</u> from the <u>May</u> 15, 2025 RPAG meeting.

NREL ATB reflects a national average; in the Pacific Northwest we find that we are on the higher end of those estimates (e.g., higher permitting and labor costs). It is important to include as many up-to-date assumptions as possible. Leveraging information from the most recent acquisition processes ensures that PSE is incorporating the most accurate information on the current market.

For base case assumptions, I'd recommend not including the ITC/PTC, but reviewing impacts in the ISP coming September/October once their continuation becomes more clear. The emerging technology should not be available in the base case, given that they are entirely undeveloped and they only affect results from 2035-2040 on. I'm not a big fan of the uncertainty adders unless you find a credible way to establish the values, which I don't believe it's possible. As mentioned, parameterizing the adders as a higher financing cost is something that could be explored more rigorously.

Thank you for the suggestion, PSE agrees and currently plans to run the analysis with and without the ITC/PTC.

Gas energy supply:

Will there be an attempt to make the delivered natural gas price resulting from the gas IRP inform the cost of natural gas to run turbines and combined cycles in the electric IRP?

Natural gas prices are an input into the electric price model. PSE uses the same natural gas prices for both parts of the analysis for consistency. These are commonly referenced as low, mid, and high prices.

In slide 40, the information provided in the table is not enough to understand the implications of each decision making model. Could you add a column that explains what decisions may be made differently due to the considerations of ISP vs IRP?

The table is not meant to show the decision-making process; the table is intended to highlight the level of information that will be incorporated in the ISP to support the development of the preferred portfolio.

In slide 41, I suggest a checkpoint in case the programmatic spend is above a certain threshold of the overall ISP capital expenditure. This is because the programmatic spending seems to be determined administratively outside of the IRP/ISP process, and if its total contribution is too high, then the whole point of the optimization in IRP/ISP is lost.

The gas utility system is required under federal law to ensure safety and reliability, limiting the spend arbitrarily would not be feasible. Furthermore, PSE is required to evaluate all planned capital additions for NPAs as part of the rate case. These programmatic spends are shorter term and targeted.

Into what extent should the baseline investments be compared against electrification costs, rather than assumed as a given?

We do have planned sensitivities regarding new environmental policies that would articulate the cost implications between the baseline investments and the building electrification costs. The forecasted baseline investments are for the reference case - the starting point for the scenario analysis, all of which will lead to the development of the preferred portfolio. The analysis you reference is part of the overall process.

How integrated is the production-pipeline-DSP planning process for gas? It appears very fragmented from the way it's presented, but I don't know much about gas planning. Does it suffer the same issues as IRP and DSP in electricity?

It is not integrated, as the gas portfolio is focused on supplying natural gas to PSE's gas delivery system. The gas delivery system analysis for this ISP is focused on identifying the costs to serve existing customers and identifying areas for NPAs, including targeted electrification. The DSP portfolio addresses specific system needs to provide safe and reliable natural gas and comply with state and federal regulations. The near-term investments are driven by known needs, location specifics are considered when known. The longer-term investments are trended based on historical performance. This will provide a more accurate representation of how the various scenarios could alter the gas

system investments and corresponding equity impacts. It does have similar challenges with the electric DSP and IRP in that specific location and actions matter and that the issues are on a shorter time horizon.

On the question in slide 49, could you create a supply curve of NPAs and feed into PLEXOS? This is the best practice for demand side resources in electric utility IRP, like the NWPCC does.

The gas system investments are location specific for safety and reliability purposes. Optimizing gas system investments in software such as PLEXOS would not yield reasonable results, as it is not an engineering model. The PLEXOS model does not need to go down to the premise level as this detailed analysis is occurring through the gas delivery system engineering models that focus on delivery of natural gas that is safe and reliable. The PLEXOS model can, however, optimize for demand side resources; for the ISP we have moved the demand side resources to the beginning of the process, removing them from the demand forecast to ensure consistent scenario analysis across the ISP. That said, we do plan to run a traditional sensitivity looking at DSR optimized, which is a very similar approach to NWPCC as you referenced.

2. Outstanding RPAG member questions, in-meeting, June 24, 2025

Will the actual process that happens down the road include that the company will procure the resource that is available at the time, so that we can make these forecasts, but essentially, at this point, why wouldn't we be resource agnostic, and be forecasting the price at different dates (which is modeled from the predictions of the individual resources)?

The ISP will identify an overall resource need and preferred portfolio. Actual utility-scale projects and contracts will be selected through the resource acquisition processes which occur outside the ISP.

The numbers presented at the meeting represent first year costs for each resource. We will use the NREL ATB resource cost curves to project out the capital cost for every year in the modeling horizon.

As a follow-up question – does the Long Duration Energy Storage project need to be large-scale to be effective? Could a smaller project, such as 50 MW or even 10 MW, still provide meaningful impact?

Yes, if the resource is cost-effective. Utility-scale resources are generally more cost-effective than distributed resources. However, we will also be modeling distributed storage as an option. We use 100 MW as a generic sizing for the models but recognize that these resources can be sized to match needs.

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Public feedback

3. Tom Kraemer on behalf of Third Act Washington, June 24, 2025, public comment opportunity.

Mr. Kraemer submitted a written transcript of his public comment, which is shown below in #4 along with PSE's response.

4. Tom Kraemer on behalf of Third Act Washington, June 24, 2025 via isp@pse.com

Thank you for the thorough presentation today. It was very helpful.

With regard to slide 14 outlining the makeup of the ISP scenarios, I have been glad to see that the scenarios include two that would bring the emissions of both utilities below the Climate Commitment Act combined no-cost allowance line. However, the wording of HB 1589, under RCW 80.86.020 (4) and (11), requires that the ISP include scenarios that will "achieve emissions reductions for both gas and electric operations equal to at least their proportional share of emissions reductions required under RCW 70A.45.020." That RCW section requires emissions reductions according to a schedule similar to those of the CCA no-cost allowance line, but the required reductions are not quite the same as the no-cost allowances. The scenario should be based on meeting the RCW 70A.45.020 requirements in HB 1589. The CCA no-cost allowances are adjusted according to factors the state applies to meet the state's overall emissions requirements. HB 1589, the Decarbonization Act for Large Combination Utilities, adds requirements specific to the utility.

Also, my understanding of the language in RCW 80.86.020, is that the requirement to achieve emissions reductions proportional to those required under RCW 70A.45.020 applies to each utility separately, not combined. Each utility must reduce its own emissions by the required percentages.

Thank you for your comments.

PSE is modeling two scenarios that will "achieve emissions reduction for both gas and electric operations equal to at least their proportional share of emissions reductions required under RCW 70A.45.020", these are Scenarios 2 (High) & 3 (High +). Please refer to slide 14 of the presentation for more information.

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5. James Adcock, June 24, 2025, public comment opportunity

James Adcock, electrical engineer, MIT. There's no way I can comment on everything in 3 minutes, especially because in general there continues to be technical failures in the presentation technology that excludes public participation. Further, Triangle has changed implementation so we cannot even contact them when there are problems. For example, Ray's survey doesn't even work. I agree with Fred that there is no real public participation in all of the various processes Puget is currently implementing. Even written input is discarded by Puget. On page 41, I think customers will convert whole houses at once, based on conversations with my friends. Page 32, blending green hydrogen is a crazy waste of electricity. Using that electricity directly in heat pumps is about 10 times more efficient. Page 22, please consider hydro as a storage capability. Modulating hydro flow to implement storage and smoothing. It is a legal requirement of BPA. For example, a product called hydro storage. Page 21, the cost of these speculative project failures is much higher than Puget is currently predicting. The modeling group should have the technical ability to correctly model the entire cost of failure of speculative projects, including the social cost of carbon. I continue to express concerns that the chosen members are sending secret, non-public messages via chat that's excluding the public even on an observational basis.

Thank you for your comments. PSE continues to work on improvements to the webinar experience within the limits of the Zoom webinar platform. [Mr. Adcock was contacted after the meeting to resolve the survey issue, and his responses were received.]



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