# PSE IRP Feedback Report
# Webinar 11: Flexibility analysis & Portfolio draft results
# December 15, 2020

*01/11/2021*

The following stakeholder input was gathered through the online Feedback Form, from December 8 through December 28, 2020. PSE's response to the feedback can be found in the far-right column. To understand how PSE incorporated this feedback into the 2021 IRP, read the Consultation Update, which will be released on January 19, 2021, one day later than reported during the December 15 webinar due to a statutory holiday (Martin Luther King Day).

Many of PSE responses reference PSE's draft 2021 IRP which is now available online.

| Feedback Form Date | Stakeholder | Comment | PSE Response |
|---|---|---|---|
| 12/9/2020 | James Adcock | Page 13 Question: I don't understand the statement "Levelized cost for low income customers used a lower benefit cost ratio adjustment"<br>What does that mean, and why do low income customers have a "lower benefit cost ratio adjustment" ? | Please note this comment references a slide that was included in the draft slide deck distributed prior to the webinar, but was not included in the final slide deck.<br>The lower benefit cost ratio means that low-income customers have a less stringent threshold to qualify a conservation measure. Even when a conservation measure is not cost effective with the standard benefit cost ratio, since the cost is higher than the benefit, it may still qualify under the lower benefit cost ratio for low-income customers. This resulted in shifting the measures to lower cost bundles in the supply curve and slightly more measures being included in the conservation supply curves overall. The result is the lower benefit cost ratio adjustment includes more measures that could be cost effective. |
| 12/9/2020 | James Adcock | Clarify the statement "Levelized cost for low income customers used a lower benefit cost ratio adjustment" and what it means, and show that it is not introducing an economic disparity in the treatment of PSE customers. | Please see response provided directly above. |
| 12/9/2020 | James Adcock | Page 22. Question: Is Page 22. Question: Is the winter peak "baseline system peak" a Morning Peak or an Afternoon Peak. What is the assumed winter "one-hour" temperature that corresponds to that Morning or Afternoon Peak? Please answer both for 2027 and for 2031. | The one-hour peak is a forecasted peak and can happen any time in the morning or evening. The temperature that corresponds to that peak is 23 degrees F. |
| 12/9/2020 | James Adcock | Please clarify whether the winter peak "baseline system peak" is a Morning Peak or an Afternoon Peak. And what is the assumed winter "one-hour" temperature that corresponds to that Morning or Afternoon Peak. Please answer both for 2027 and for 2031. | The one-hour peak is a forecasted peak and can happen any time in the morning or evening. The temperature that corresponds to that peak is 23 degrees F. |
| 12/9/2020 | James Adcock | Page 21. Question: What is meant by the three blue highlighted boxes? As opposed to the new acqusition which are not inside the three blue highlighted boxes? | The three blue highlighted boxes are intended to be a visual cue for the presentation. They highlight the resource additions related to the retirements of Colstrip and Centralia as well as the additional peaking capacity and storage resources discussed on slide 30. |
| 12/9/2020 | James Adcock | Please clarify what is meant by the three blue highlighted boxes? As opposed to the new acqusition which are not inside the three blue highlighted boxes? | Please see response provided directly above. |
| 12/9/2020 | James Adcock | Page 32. Question: When will the new Peakers that are being acquired planned to be retired? Do they continue to exist after 2045, or will they be retired prior to 2045? If they continue to exist after 2045 how will you use them? Will you just use them and then "pay the penalty" -- pay the "alternative compliance fee" ? Or how will you continue to use them after 2045? | The generic peaking capacity modeled in the AURORA model has an expected life of 30 years. The modeling horizon of the AURORA model does not extend past 2045. Any carbon-emitting thermal plants that are still in use after 2045 would be subject to CETA penalties, and the economic viability of those resources would be re-evaluated under those new conditions. The model currently uses peaking capacity only when necessary to meet peak demand.<br>PSE is doing further analysis through sensitivities to understand the need for peaking capacity and evaluating the use of alternative fuels. |
| 12/9/2020 | James Adcock | Please answer these questions clearly and unambiguously. We ratepayers worry about paying for something just to see it be prematurely retired. | Please see response provided directly above. |
| 12/9/2020 | James Adcock | Page 34. Question: If, by implication, WA wind, in comparison to WY and MT wind, are not well-matched to PSE's load profile, then how do you actually "use" them under CETA requirements to serve PSE customers? | WA wind still provides energy and meets PSE's loads in different seasons and times of day. |

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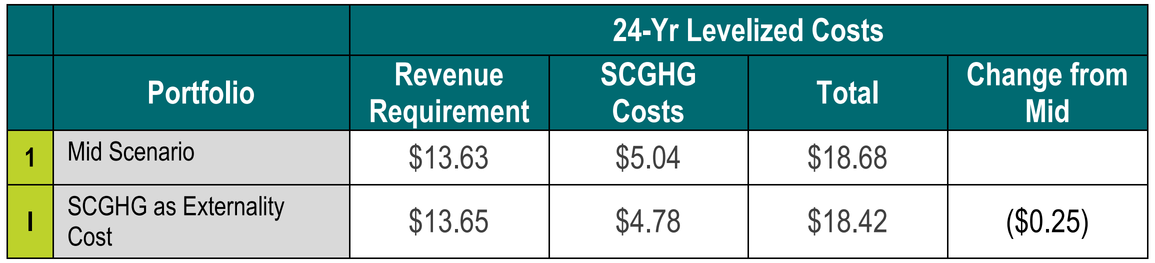
| 12/9/2020 | James Adcock | Please clearly and unambiguously answer the question. | Please see response provided directly above. |
| 12/9/2020 | James Adcock | Page 34. Question: What is the actual value of the big red "X" on this page? | Please note this comment references a slide that was included in the draft slide deck, which was later updated. We apologize any confusion this may have caused. |
| 12/9/2020 | James Adcock | Please specify what the actual value is of the big red "X" on this page. | Please see response provided directly above. |
| 12/9/2020 | James Adcock | Page 38. Question: So when you say "By 2045, emissions are coming from market purchases and remaining peaker plants" is PSE saying that they are plannning to "pay the penalty" for these emissions -- i.e. PSE plans to pay the CETA "Alternative Compliance" costs? | PSE has factored the alternative compliance costs into the total portfolio costs. It starts at meeting 80% of the forecast in 2030 and reduces to zero by 2045 because all load is met with renewables. PSE is conducting additional sensitivities around retiring peakers before 2045 and moving to an alternative fuel for CETA compliance. |
| 12/9/2020 | James Adcock | Please clarify that when you say "By 2045, emissions are coming from market purchases and remaining peaker plants" whether or not PSE is saying that they are plannning to "pay the penalty" for these emissions -- i.e. that PSE plans to pay the CETA "Alternative Compliance" cost of $84 per megawatt hour. | Please see response provided directly above. |
| 12/9/2020 | James Adcock | Page 39. Question: I really don't understand this page. I am asking that can you spend additional time explaining it so that I and other can actually understand it? And/or plan to have time so that people can ask questions to understand it? | Please note that this response and the figures below are excerpts from Chapter 8 of PSE's 2021 IRP Draft, dated January 2021.<br>Sensitivity I looks at adding the SCGHG as a variable dispatch cost instead of a fixed planning adder. The changes brought on by changing SCGHG to an externality cost are minor. The model optimizes dispatch of existing gas plants to minimize cost, while newly acquired peaking capacity is largely unused. The sensitivity resulted in more peaking capacity being built than the Mid Scenario, but the average capacity factors of the newly built plants averages to 0.3 percent by 2045.<br>The costs of the portfolio remain similar throughout the time horizon. Sensitivity I reached a higher annual cost in 2045 as a result of increased biomass builds starting in 2036. Overall, the cost differences between these portfolios are minor, with Sensitivity I purchasing slightly more expensive resources in the later years. |

*Figure 8-35: 24-year Levelized Costs – Mid and Sensitivity I portfolios*



| | | 24-Yr Levelized Costs | | | |
|---|---|---|---|---|---|
| | Portfolio | Revenue Requirement | SCGHG Costs | Total | Change from Mid |
| 1 | Mid Scenario | $13.63 | $5.04 | $18.68 | |
| I | SCGHG as Externality Cost | $13.65 | $4.78 | $18.42 | ($0.25) |

*Figure 8-36: Annual Portfolio Costs – Mid Scenario and Sensitivity I*

| Feedback Form Date | Stakeholder | Comment | PSE Response |
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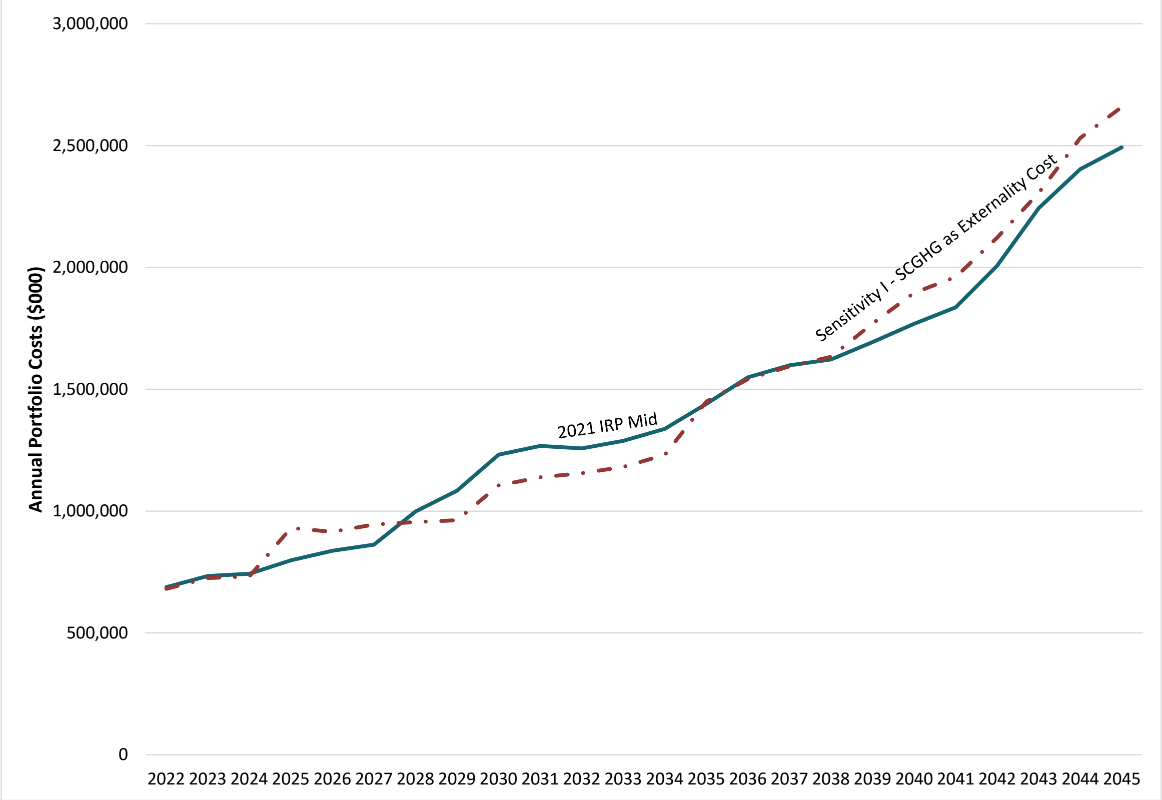

The model in Sensitivity I builds a large amount of Washington wind capacity in 2025 as Colstrip and Centralia are retired. However, the total Washington wind resources added to the Sensitivity I is lower by 300 MW nameplate capacity compared to the Mid Scenario. This can be seen as the costs increase in 2025. However, the sensitivity adds less conservation than the mid portfolio and slightly more peaking capacity.

| | Portfolio | DSR | DER Resources | Demand Response | Biomass | Solar | Wind | Storage | Peaking Capacity | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Mid Scenario | 1,497 | 118 | 121 | 15 | 1,393 | 3,750 | 600 | 948 | 8,442 |
| I | Social Cost of Greenhouse Gases as an Externality Cost in the Portfolio Model | 1,372 | 118 | 141 | 120 | 1,394 | 3,450 | 600 | 966 | 8,161 |

The reduced usage of new peaking capacity leads to an overall decrease in the emissions from resources in both portfolios. Sensitivity I has a lower emissions in the earlier years because of the additions of more renewable resources in years 2025 and 2026, but both portfolios converge back together by 2030 with the 80% renewable resources requirement. Figure 8-39 shows the emissions of the Sensitivity I portfolio, where PSE is producing below two million short tons of emissions in the year 2045. The portfolio does begin to lean more on market purchases, which have a CETA-specified emission rate of 0.437 metric tons of $CO_2$ per MWh.

*Figure 8-39: Sensitivity I – Portfolio Emissions – Mid Scenario and Sensitivity I (includes calculated emissions on market purchases)*

| Feedback Form Date | Stakeholder | Comment | PSE Response |
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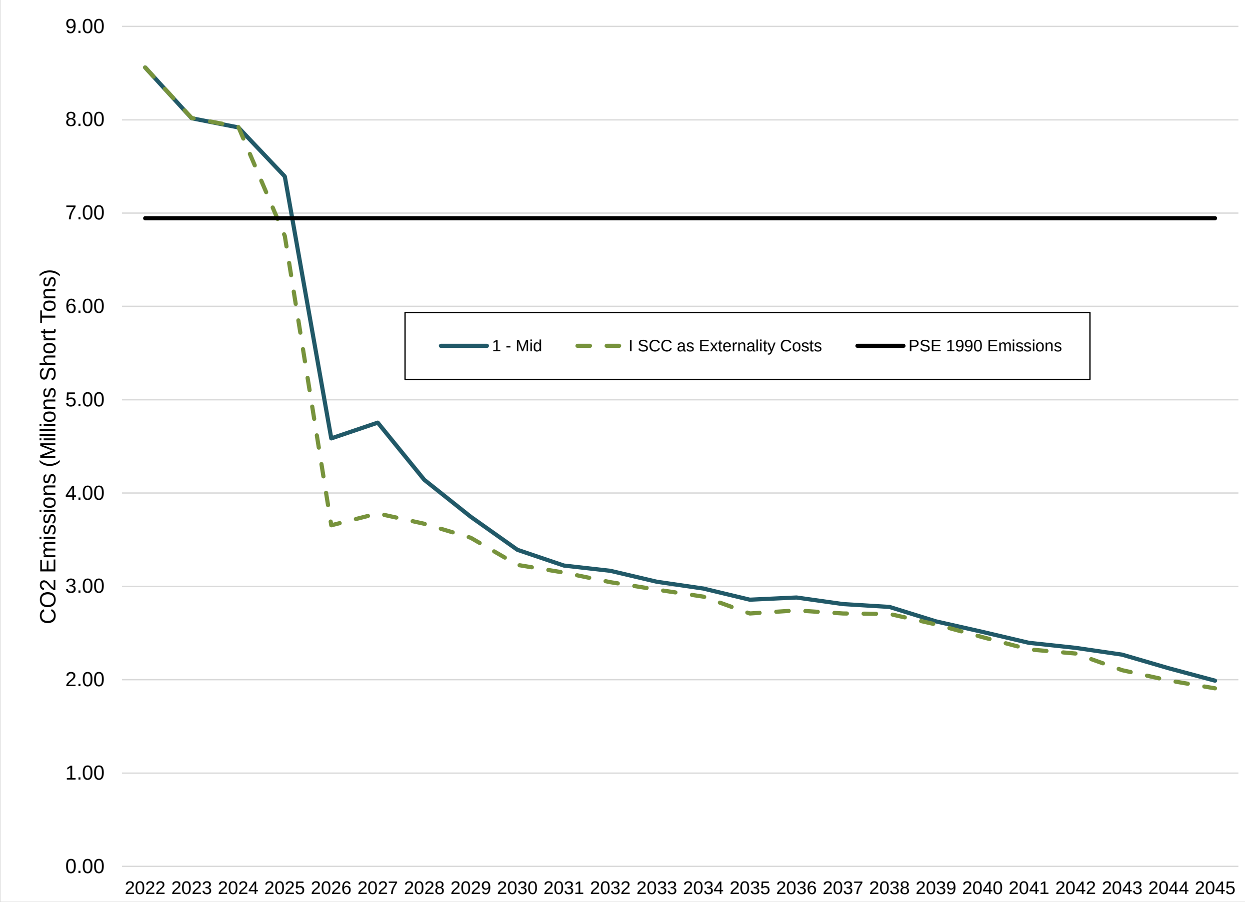
| | | |  |
| 12/9/2020 | James Adcock | Please can you spend additional time explaining it so that I and other can actually understand it? And/or plan to have time so that people can ask questions to understand it? | Please see response provided directly above. |
| 12/9/2020 | James Adcock | Page 40. Question: I'm trying to understand this page. What it seems to be saying is that it costs less to have PSE comply with the lower emissions requirements of CETA than when PSE had greater freedom to pollute just about as much as they wanted. Is that correct? | See reply above |
| 12/9/2020 | James Adcock | Please clarify whether or not it costs less to have PSE comply with the lower emissions requirements of CETA than when PSE had greater freedom to pollute just about as much as they wanted. | See reply above. |

| Feedback Form Date | Stakeholder | Comment | PSE Response |
|---|---|---|---|
| 12/9/2020 | James Adcock | Page 41. Question: I'm trying to understand this page. When I read the CETA law (section 9) it seems to state clearly that the alternative compliance costs (for Peakers) is $84 per megawatt hour. Why are you using a different calculation here that somehow relates to California, and not the $84 per megawatt hour required under Washington State Law? | PSE first discussed the alternative compliance costs and consulted with stakeholders at the September 1 webinar. PSE requested feedback from stakeholders regarding prioritization of the options for the 20% alternative compliance to reach carbon neutral target by 2030 in the 2021 IRP.<br>PSE received one suggestion regarding this through the feedback forms.<br>Feedback from Joni Bosch, NWEC:<br>In response to the question posed on prioritizing options for the 20% alternative compliance actions that might be addressed in the 2021 IRP, NWEC would urge PSE to model an aggressive amount of conservation and demand response. Beyond the required conservation and demand response required in sections .040 and .050 of CETA, additional innovative conservation, efficiency, storage and demand response should be considered for Energy Transformation Projects. Exploring those has the double impact of further reducing/managing load and achieving additional GHG reductions.<br>PSE created a portfolio that increased demand response, storage and distributed resources as Sensitivity V and W.<br>For the baseline assumption and comparison, PSE wanted to use a price forecast for the alternative compliance costs. PSE feels that the California carbon price is a reasonable assumption, however we are open for discussion and can also evaluate other price forecasts to get a range of the alternative compliance costs.<br>PSE also ran a sensitivity where the portfolio reaches 100% renewable resources in 2030 instead of relying on alternative compliance. |
| 12/9/2020 | James Adcock | Please clarify why are you using a different calculation here that somehow relates to California, and not the $84 per megawatt hour required under Washington State Law? | For the baseline assumption and comparison, PSE wanted to use a price forecast for the alternative compliance costs. PSE feels that the California carbon price is a reasonable assumption, however we are open for discussion and can also run another cost to get a range of the alternative compliance costs. |
| 12/9/2020 | James Adcock | Page 42. Question: I'm trying to understand this page. You state that CC Plants capacity factors are below 5%, but your Peaker capacity factors (at least in recent years) are also below 5%, so why wouldn't you just retain the CC Plants as "emergency use only" to run proactively when the local weather predictions are for unusually hot or cold weather? Are you stating that maintaining old CC Plants is more expensive than buying new Peaker Plants -- when the new Peaker Plants need to be retired in 15 years anyway? | Your statement to "just retain the CC Plants as "emergency use only" to run proactively when the local weather predictions are for unusually hot or cold weather" is correct. To keep the old CCCT plants to run for "emergency use only" is lower cost than buying new resources. |
| 12/9/2020 | James Adcock | Please clarify given that CC Plants capacity factors are below 5%, and your Peaker capacity factors (at least in recent years) are also below 5%, so why wouldn't you just retain the CC Plants as "emergency use only" to run proactively when the local weather predictions are for unusually hot or cold weather? | Please see response provided directly above. |
| 12/9/2020 | James Adcock | Page 54 Question: I don't understand the statement "Levelized cost for low income customers used a lower benefit cost ratio adjustment"<br>What does that mean, and why do low income customers have a "lower benefit cost ratio adjustment" ? | Please note this comment references a slide that was included in the draft slide deck distributed prior to the webinar, but was not included in the final deck.<br>The lower benefit cost ratio means that low-income customers have a less stringent threshold to qualify a conservation measure, so even when a measure is not cost effective with the standard benefit cost ratio since the cost is higher than the benefit, it may still qualify under the lower benefit cost ratio for low-income customers. This resulted in shifting the measures to lower cost bundles in the supply curve and slightly more measures being included in the conservation supply curves overall. The result is the lower benefit cost ratio adjustment includes more measures that could be cost effective. |
| 12/9/2020 | James Adock | Please clarify statement "Levelized cost for low income customers used a lower benefit cost ratio adjustment" and explain what does that mean, and why do low income customers have a "lower benefit cost ratio adjustment" ?<br>Verify to participants that this does not mean that low income customers will receive less services in this area from PSE than for not-low-income customers. | Please see response provided directly above. See above. |

| Feedback Form Date | Stakeholder | Comment | PSE Response |
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| 12/17/2020 | Christine Bunch, Seattle Office of Sustainability and Environment | PSE said on the call that the gas analysis is to support identifying the right amount of resources and to avoid overbuilding. It was noted that DSR would meet the needs except in the high demand case. To that end, I asked a question about how local and state regulation (ie. electrification) was factored into the analysis. The response from PSE was that it was feedback received earlier but that it was "not factored in at this point, but looking into it at a future date."<br>No specifics were provided on the future date and whether it will be for sure included in the final IRP. | The gas to electricity conversion sensitivity will be included in the final IRP on April 1, 2021. |
| 12/17/2020 | Christine Bunch, Seattle Office of Sustainability and Environment | Please provide specific dates of when gas regulatory factors will be included in a sensitivity analysis and that it will be included in this round of the IRP. | The gas to electricity conversion sensitivity will be included in the final IRP on April 1, 2021. |
| 12/21/2020 | Katie Ware, Renewable Northwest | Please see Attachment 01. 2020-12-21 RNW Feedback re PSE Flexibility Analysis and Portfolio Draft Results.pdf for the complete submittal from Renewable Northwest. Key questions/suggestions have been paraphrased below by PSE for brevity. | Thank you for your thoughtful questions and comments. |
| 12/21/2020 | Katie Ware, Renewable Northwest | Flexibility Analysis: [paraphrased by PSE, see attachment for original submittal] Renewable Northwest encourages PSE to incorporate four dimensions of flexibility (absolute power output capacity, speed of power output change, duration of energy levels and carbon intensity) into PSE's flexibility analysis. | Thank you for breaking down the key components of flexibility. PSE will keep these parameters in mind as we continue to refine our analysis. |
| 12/21/2020 | Katie Ware, Renewable Northwest | Flexibility Analysis: [paraphrased by PSE, see attachment for original submittal] Renewable Northwest encourages PSE to examine specific dispatch characteristics of the sub-hourly PLEXOS model to pin point inconsistencies with previous flexibility assessments, particularly the flexibility benefit of reciprocating peaker plants of $417.25/kW-yr. | PSE has revised the nameplate capacity of the reciprocating peaker plant to 216 MW, which in turn reduced the calculated flexibility benefit to $35/kW-yr. Please note this revised flexibility value also incorporates some subtle revisions to the flexibility analysis methodology. PSE is continuing to refine its methodology and this value remains draft. |
| 12/21/2020 | Katie Ware, Renewable Northwest | Flexibility Analysis: [paraphrased by PSE, see attachment for original submittal] Renewable Northwest encourages PSE to consider the value to 'controllable' solar and wind power plants. | PSE is aware of the growing interest and perceived value of controllable solar and wind resources. PSE will require time to understand how to best incorporate controllable solar and wind resources into its existing modelling frameworks and aims to include these resources in future IRP cycles. |
| 12/21/2020 | Katie Ware, Renewable Northwest | Flexibility Analysis: [paraphrased by PSE, see attachment for original submittal] Renewable Northwest encourages PSE to consider incorporating a 6hr Li-Ion battery into the IRP. | Given the effort required to incorporate a new generic resource into the modeling environment, PSE is not able to incorporate a 6hr Li-Ion battery into the 2021 IRP. However, such a resource may be included in future IRP cycles. |

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<tr><th>Feedback Form Date</th><th>Stakeholder</th><th>Comment</th><th>PSE Response</th></tr>
<tr><td>12/21/ 2020</td><td>Katie Ware, Renewable Northwest</td><td>Flexibility Analysis: [paraphrased by PSE, see attachment for original submittal] Renewable Northwest encourages PSE to provide a flexibility value of the ‘diversity savings’ from participation in the Energy Imbalance Market.</td><td>The EIM market is incorporated into the real time, fifteen-minute dispatch. The flexibility benefit then takes the change in dispatch from the day ahead and hourly dispatch to the real time dispatch and therefore the EIM benefits are incorporated into the flexibility benefit.</td></tr>
<tr><td>12/21/ 2020</td><td>Katie Ware, Renewable Northwest</td><td>Portfolio Draft Results: [paraphrased by PSE, see attachment for original submittal] Renewable Northwest suggests that ELCC values for storage resources should be higher than described in the presentation, particularly pumped hydro storage.</td><td>Thank you for you feedback and concern for the ELCC analysis. In the draft 2021 IRP, Chapter 7, Resource Adequacy Analysis, PSE describes the analysis around energy storage ELCC.<br><br>Below is an excerpt from Chapter 7, page 7-31:<br><br>**STORAGE CAPACITY CREDIT.** The estimated peak contribution of two types of batteries were modelled in RAM as well as pumped hydro storage. The lithium-ion and flow batteries modeled can be charged or discharged at a maximum of 100 MW per hour up to two, four or six hours duration when the battery is fully charged. For example, a four-hour duration, 100 MW battery can produce 400 MWh of energy continuously over four hours. Thus, the battery is energy limited. The battery can be charged up to its maximum charge rate per hour only when there are no system outages. The battery can be discharged up to its maximum discharge rate or just the amount of system outage (adjusted for its round-trip [RT] efficiency rating) as long as there is a system outage and the battery is not empty.<br><br>As stated previously, the LOLP is not able to distinguish the impacts of storage resources on system outages since it counts only draws with any outage event but not the magnitude, duration and frequency of events within each draw. Because of this, the capacity credit of batteries was estimated using expected unserved energy (EUE). The analysis starts from a portfolio of resources that achieves a 5 percent LOLP, then the EUE from that portfolio is calculated. Each of the storage resources is then added to the portfolio, which leads to lower EUE. The amount of perfect capacity taken out of the portfolio to achieve the EUE at 5 percent LOLP divided by the peak capacity of the storage resource added determines the peak capacity credit or ELCC of the storage resource. The estimated peak contribution of the storage resources is shown in Figure 7-19. The low peak capacity contribution for energy is because these are short duration resources. As shown in figures 7-8 and 7-12 above, loss of load events can have extended durations of 24 hours or more. Since energy storage resources have a short discharge period, they have little to contribute during extended duration events.<br><br>*Figure 7-19: Peak Capacity Credit for Battery Storage Based on EUE at 5% LOLP*
<table>
<tr><th>BATTERY STORAGE</th><th>Capacity (MW)</th><th>2021 IRP Year 2027</th><th>2021 IRP Year 2031</th></tr>
<tr><td>Lithium-ion, 2 hr, 82% RT efficiency</td><td>100</td><td>12.4%</td><td>15.8%</td></tr>
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<table>
<tr><td><b>Lithium-lin, 4 hr, 87% RT efficiency</b></td><td>100</td><td>24.8%</td><td>29.8%</td></tr>
<tr><td><b>Flow, 4 hr, 73% RT efficiency</b></td><td>100</td><td>22.2%</td><td>27.4%</td></tr>
<tr><td><b>Flow, 6 hr, 73% RT efficiency</b></td><td>100</td><td>29.8%</td><td>35.6%</td></tr>
<tr><td><b>Pumped Storage, 8 hr, 80% RT efficiency</b></td><td>100</td><td>37.2%</td><td>43.8%</td></tr>
</table>
<p>The below is an excerpt from Chapter 3, page 3-25:</p>
<p>Figure 3-14 is a 12x24 table that shows the loss of load hours prior to the addition of new resources. The plot represents a relative heat map of the number hours of lost load summed by month and hour of day. The majority of the lost load hours still occur in the winter months. From this chart, the large blocks of yellow, orange, and red in January and February illustrate long duration periods, 24 hours or more, with a loss of load event. The portfolio optimization model must meet these long duration capacity shortfall events using generic resources. Given current technologies, energy storage and demand response do not completely meet the peak capacity needs because of their short duration of availability.</p>
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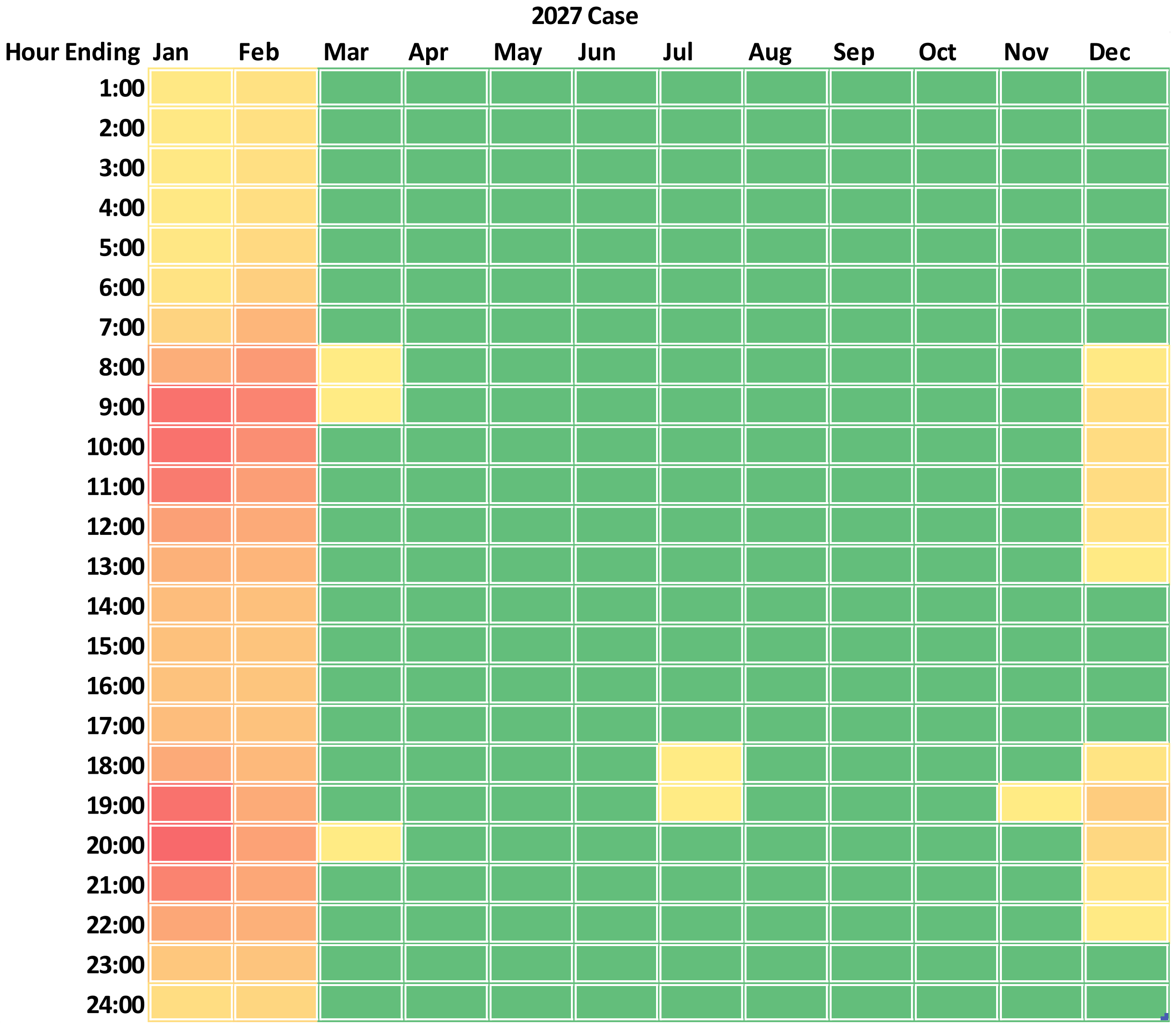
| Feedback Form Date | Stakeholder | Comment | PSE Response |
|---|---|---|---|
| | | | *Figure 3-14: Loss of Load Hours for 2027*<br> |
| 12/21/2020 | Katie Ware, Renewable Northwest | Portfolio Draft Results: [paraphrased by PSE, see attachment for original submittal] Renewable Northwest asks why additional peaking capacity resources are added to the portfolio and seemingly displacing dispatch of existing thermal resources. | New peaking capacity resources are added to the portfolio to meet peak capacity, not to provide baseload energy. Baseload energy is being replaced with renewable resources to meet CETA requirements. This is the reason why annual capacity factors of existing thermal resources decline with time. The new peaking capacity is needed to meet demand during hours when there is not enough renewable resources to meet needs. During peak events it may be necessary to dispatch all thermal resources old and new alike. |
| 12/21/2020 | Katie Ware, Renewable Northwest | Portfolio Draft Results: [paraphrased by PSE, see attachment for original submittal] Renewable Northwest request an additional sensitivity which includes 6hr Li-Ion battery and 8-10 hr pumped hydro storage resources. | Given the effort required to incorporate a new generic resource into the modeling environment, PSE is not able to incorporate 6hr Li-Ion battery as this point in the process. However, PSE is modeling 8-hour pumped storage hydro in sensitivity N and P and they are described in Chapter 8, Electric Analysis, of the draft 2021 IRP. |

| Feedback Form Date | Stakeholder | Comment | PSE Response |
|---|---|---|---|
| 12/21/2020 | Katie Ware, Renewable Northwest | Portfolio Draft Results: [paraphrased by PSE, see attachment for original submittal] Renewable Northwest asks for context around the lower-than-expected ELCC of pumped hydro storage. | Thank you for you feedback and concern for the ELCC analysis. In the draft 2021 IRP, Chapter 7, Resource Adequacy Analysis, PSE describes the analysis around energy storage ELCC. |
| 12/21/2020 | Katie Ware, Renewable Northwest | Portfolio Draft Results: [paraphrased by PSE, see attachment for original submittal] Renewable Northwest asks to know the duration of storage resources used in Sensitivity P. | Sensitivity P used a 2hr Li-Ion battery as the selected 'must-take' storage resource, given it has the lowest revenue requirement of any storage resource. A full discussion and results of Sensitivity P are located in Chapter 8, Electric Analysis, of the draft 2021 IRP.<br>PSE also ran a sensitivity P using an 8-hour pumped hydro storage resource and the results are included with sensitivity P in Chapter 8. |
| 12/21/2020 | Katie Ware, Renewable Northwest | Portfolio Draft Results: [paraphrased by PSE, see attachment for original submittal] Renewable Northwest requests that PSE model for its draft IRP a sensitivity which, independent of existing natural gas plants (i.e. unlike PSE's anticipated sensitivities N and O),<br>forces the model to select nonemitting capacity resources including batteries, pumped hydro, and renewables on an economic basis. This sensitivity would hone in on the cost and capability of nonemitting resources to provide system flexibility and peak capacity in a strategy most consistent with the state's clean energy standards. | Thank you for your feedback. PSE will follow up with renewable northwest on how this new sensitivity would be different than sensitivities N and O. |
| 12/21/2020 | Elyette Weinstein | This analysis proposes gas "peaker plants'" to meet resource adequacy needs. These plants are not necessary to meet such needs after 2026.<br>You have failed to adequately develop demand response resources to meet this need. You have presented no evidence that you persistently have made a good faith effort to meet this need by obtaining renewable power from such entities as BPA.<br>You rely on gas to meet these needs until near the deadline for 100% renewable energy so that the cost of suddenly obtaining such resources will meet the cost cap and you will be off the hook. I expected PSE to "game the system." Once again, you have met my dismal expectations. Your plan does not comply in good faith with CETA's intent. | Thank you for your concern regarding the analysis. PSE has addressed these issues in the draft 2021 IRP now available at www.pse.com/irp. You may consider reviewing Chapters 1, Executive Summary and 3, Resource Plan Decisions.<br>PSE has run several sensitivities N, O, and P where existing thermal resources have been removed from the portfolio and/or no new peaking capacity is allowed to be added to the portfolio. Results of these sensitivities are located in Chapter 8, Electric Analysis. PSE is also exploring alternatives fuels such as hydrogen and biodiesel which are CETA compliant fuels and the analysis will be included in the final IRP. |
| 12/22/2020 | Nathan Sandvig, Rye Development LLC | These comments are provided on behalf of the Swan Lake and Goldendale pumped storage projects (the "Projects"). While Puget has provided several sensitivities to its Draft IRP results, Puget has NOT provided a sensitivity where no new natural gas generation is built in the IRP timeframe. Given the political climate and environmental opposition to constructing a new gas-fired generation facility, it is virtually impossible to construct these types of new generation resources. This "no new gas" scenario is also the most likely future scenario, given Washington's enactment of the Clean Energy Transformation Act ("CETA"), which provides very limited circumstances under which Puget could construct new natural gas-fired generation (e.g., RCW 19.405.090). Thus, the Projects strongly urge Puget to conduct an additional sensitivity that prohibits future natural gas development. Furthermore, the Projects request that Puget provide a demonstration that new natural gas-fired generation would be allowable under the few and limited CETA provisions allowing construction of such resources, particularly including violation of | PSE has run two sensitivities where all gas plants are removed by 2030 and 2045. These sensitivities are located in Chapter 8 of the draft 2021 IRP.<br>PSE has added a pumped storage hydro option for sensitivity N and P in the draft 2021 IRP, and are located in chapter 8. PSE experienced some problems with sensitivity O and this will need to be fixed for the final IRP and will run with both a battery storage option and a pumped storage hydro option. |

| Feedback Form Date | Stakeholder | Comment | PSE Response |
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| | | reliability standards and, if violations are possible, whether pumped storage could help alleviate or solve those potential violations.<br>Similarly, of the sensitivities run by Puget, the Projects would like to see additional analysis for pumped storage in this IRP, particularly as part of scenarios N, O, and P. The Projects believe these scenarios represent reasonably likely future outcomes, so it is incumbent upon Puget to fully consider all types of storage resources that may be helpful in achieving these reasonably likely outcomes. Additionally, as noted above, a “no new gas” scenario should also analyze whether pumped storage could alleviate the reasons under CETA that would allow Puget to construct a new gas-fired resource. Thus far, Puget has indicated pumped storage was not fully evaluated as part of these draft results and the Projects strongly urge Puget to conduct that additional analysis.<br>Finally, the Projects are also concerned about the over-reliance on batteries in many of Puget’s future scenarios. For example, scenario P calls for nearly 3,800 MW of additional batteries in 2026. Attached to these comments is a series of 3 research papers by Navigant Consulting that highlights some of the complications, challenges, and pitfalls with relying too heavily on batteries, including the significant environmental degradation impacts and hidden costs of those projects. Of particular note, the Projects would highlight for Puget that a key issue with proposing acquisition of Li-ion batteries for raw capacity needs is their likely performance for this new application. For example, a recent presentation by Energy GPS suggests that batteries are well-suited for meeting ancillary services needs; however, they are largely unable provide significant energy or capacity to utilities, meaning they are ill-suited to meet the upcoming capacity deficit in the Pacific Northwest. See, See The Next Technology – Batteries, Energy GPS LLC, Dec. 17, 2020 at 6-11, available at: https://content.energygps.com/files/062e7ca946d147fd1212bcfe5c88a3993ba8cbe9/EGPS_Webinar_TheNextTechnology_Final.pdf.<br>Additionally, there is virtually no data on Li-ion battery performance for utility scale applications. Until battery installations of over 50 MW have run for at least 1-3 years in an operational grid/utility environment, it is impossible to credibly judge whether a four-hour discharge duration and a 10-15 year lifespan (as currently projected) are in fact accurate performance indicators. Currently planned Li-ion battery installations, especially in California, should provide such data, but it will probably not be sufficiently robust to validate (or not) currently advertised Li-ion performance metrics until the post-2025 timeframe. The need for more data is especially important since, in an operational utility environment, these large battery installations will be fully charging and discharging several times/day over a multi-month/year period. Similar to a cell phone battery, the more it is used, the quicker its capacity degrades, meaning the currently-asserted and modeled assumptions regarding charge/discharge and useful life cannot be fully vetted until more information is available.<br>In addition, longer storage durations (which Li-ion batteries currently do not provide) are especially important in the Pacific Northwest where the region is facing multi-hour/multi-day nighttime winter capacity shortages from 2020-2030 as coal plants retire and the no new gas political sentiment prevents construction of new combustion turbines to replace that retiring coal capacity. This dynamic leaves | |

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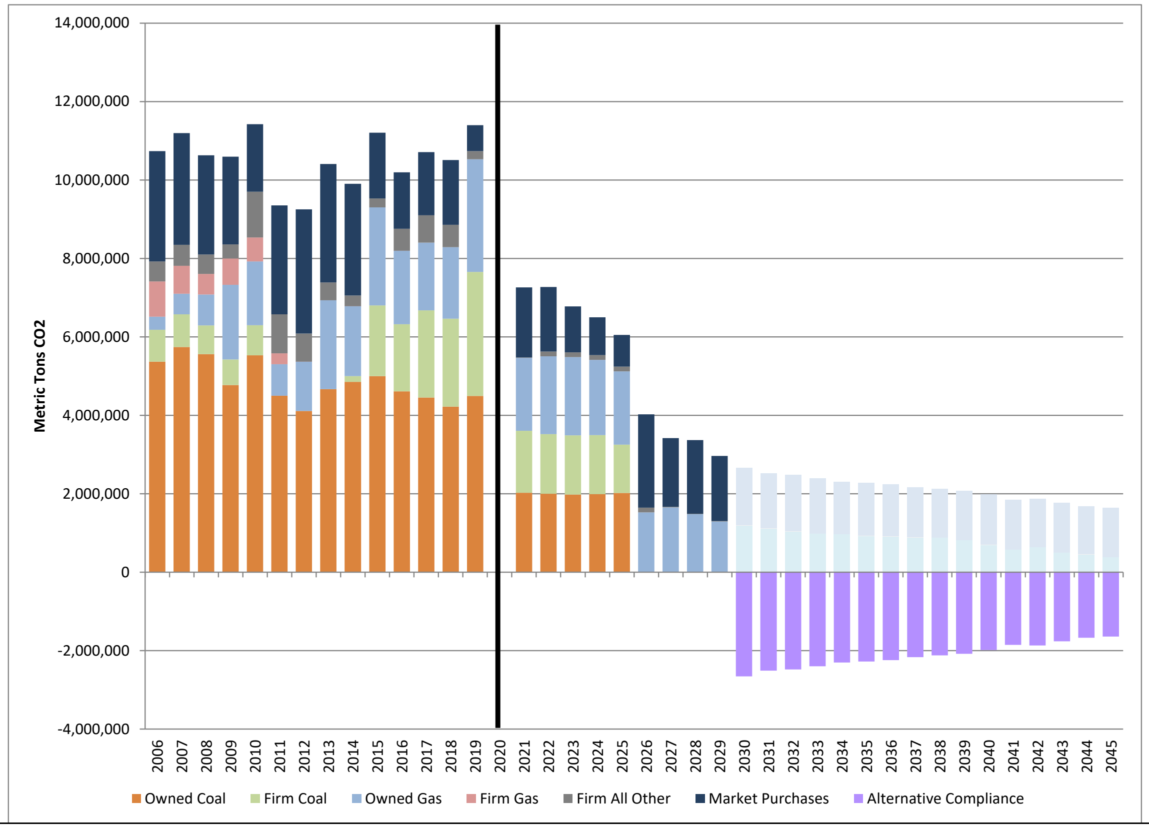
| | | pumped storage as one of the few remaining viable capacity solutions. Therefore, in light of the numerous issues associated with Li-ion batteries, the Projects request that Puget consider the attached materials in further detail and reflect them in their analysis of batteries as a potential storage solution, particularly as these resources compare to a clean, stable, grid-scale storage project like pumped storage.<br>The Projects look forward to continuing to participate in Puget's IRP process and appreciates the opportunity to provide these comments on the initial, Draft IRP Results. | |
| 12/26/2020 | Willard Westre, Union of Concerned Scientists | Slide 11 from first Webinar release (Model Assumptions) – More explanation is needed regarding Economic Retirement of gas fired turbines. Does this mean retirement when fully depreciated or does it mean retirement when operational cost of an existing turbine is higher than the combined operational cost and purchase cost of a new turbine? Or when new renewable energy resources are less costly than existing turbines? Are there current retirement plans for this equipment before 2045? If so, when? This has implications in other slides. | In the retirement decision analysis in the Aurora model, the revenue requirement of an existing resource considered (includes depreciation costs, operational costs, and revenue from energy generated) in comparison to the cost of operating and building a new resource. The model did not select any economic retirement of existing PSE thermal generation resources in the Mid Scenario portfolio.<br>Sensitivity N in the draft 2021 IRP assumes that all existing PSE thermal generation resources are retired by 2030 regardless of economic viability. |
| 12/26/2020 | Willard Westre, Union of Concerned Scientists | Slide 17 – Thank you for including this chart, but there are some unclarities:<br>1. The emissions suggested by the bars in the chart seem to indicate that the reduction achieved by 2029 is closer to 90% than 62%. The 62% seems to be the reduction by 2021. Can you clarify?<br>2. The chart shows a huge emissions reduction in the owned-gas-bar of about 2200 tons between 2019 and 2021. That reduction is larger than the gas emissions in 2026 indicating a large unused gas MW capacity at that time. This seems to contradict the need for new peakers. Can you explain why the unused existing gas capacity cannot be used instead of new peakers? | You are correct, in preparing the draft IRP, we found an error in this chart. The updated chart is provided in this report and will be included in the final IRP; the reduction from 2019 to 2029 is 75%.<br> |
| 12/26/2020 | Willard Westre, | Slide 21 – A slide in the first release of the webinar presentation (which is now not available) showed a more detailed breakdown of the wind resource additions. It | All 750 MW of available capacity from MT is assumed used by 2026 to meet peak capacity need. |

| Feedback Form Date | Stakeholder | Comment | PSE Response |
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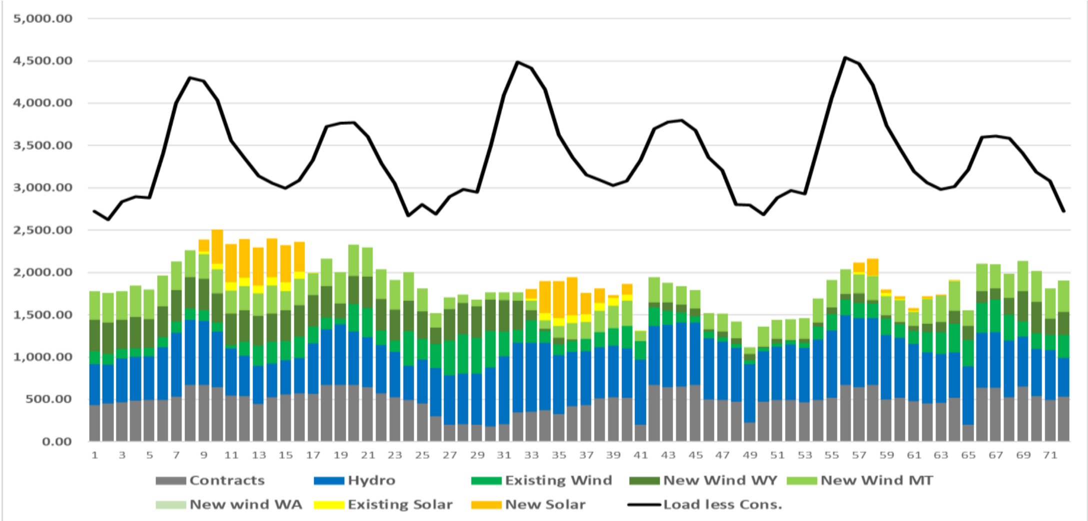
|  | Union of Concerned Scientists | showed 400 MW addition of MT wind in 2025, 400MW of WY wind in 2026, and 350MW of MT wind in 2044. The choice of MT wind first confirms this is the lowest cost resource. Why is the 350MW of MT wind not chosen next as it is also the lowest cost? It is lower cost than WY wind because WY wind requires new transmission. It is lower cost than WA wind because it has a higher capacity factor and higher resource adequacy. It is lower cost than new peakers. This delay also wastes half of the critical MT transmission resource for 20 years. There should not be a resource adequacy reason for this since the nearly 1000MW of WA wind is already mostly saturated. There seems to be an arbitrary cap on MT wind. Will PSE adhere to the lowest cost requirement and reevaluate this?<br>If the 350MW was moved up to 2026, the addition of the 2 MT (400 & 350) and 1 WY (400) wind resources (1150MW total) provides an equivalent peaking capacity as the 474MW of peakers. This amount could also be increased from 1150-1233MW if PSE agrees to my firm transmission request (noted as Slide 36). Will PSE add the 350MW MT resource and drop the addition of 474MW of peakers in 2026?<br>Also, why does it take 8 years to accelerate the introduction of Demand Response and what does it take to introduce it faster? |  |
| 12/26/2020 | Willard Westre, Union of Concerned Scientists | Slide 23 - The chart on the upper left does not seem to justify new peakers. It appears that the current CCCT turbine capacity (1293MW) and the current peaker capacity (612MW) are not used at full capacity in concert. This 1905MW of thermal resources should be adequate to handle the 1500MW peaks. Using them at capacity together would appear to eliminate the need for the new peakers at least in the pre-2030 period. Will you please rerun the analysis with full existing peaker and CCCT dispatch allowed?<br>Also, there is no Demand Response shown here. It seems obvious that several DR measures are very useful in addressing peak loads, e.g., timed water heating and car charging and emergency curtailment. The occurrence described here is rare. Will PSE consider increased use of DR to help cover these load peaks? | We apologize for the confusion regarding this chart. This chart shows the dependence on market availability. If no market was available, the largest difference at peak happens on Jan. 3 at 8 am at 4,488 MW and the total renewable resources and contracts adds up to 1,763 MW, leaving the portfolio 2,725 MW short. The existing thermal fleet adds up to 2,070 MW at peak, leaving the portfolio short 655 MW. Which can be filled by the new peaking capacity and demand response added to the portfolio.<br> <br>PSE will work at look at making the adjustment that you suggest to make this chart more understandable. |
| 12/26/2020 | Willard Westre, Union of Concerned Scientists | Slide 36 - Thermal resources operate at near 100% Capacity Factor, renewables much less. So, it takes several times as many nameplate MWs to fill a transmission line to capacity with the current 100% of generation nameplate transmission requirement. This is why the Sensitivity D (Transmission as a % of Nameplate) analysis is important. In the presentation it was stated that the majority of time that a wind turbine is operating it is at nameplate rating. Given a Capacity Factor of 40%, this means that means at nearly 60% of the time it would be producing at zero. This does not meet the “smell test”. Will PSE please supply the data that is behind this assertion? This is critical because it defines the time that increased | Thank you for your thoughtful comments. Provided below is a histogram of the hourly capacity factor for Eastern Montana Wind. You are correct, that a great deal of the time, there is no production (left most column). However, when the facility is producing power, it is most often producing rated power (right most column). Therefore, as the analysis shows, even small reductions in transmission capacity result in significant quantities of curtailed energy. |

| Feedback Form Date | Stakeholder | Comment | PSE Response |
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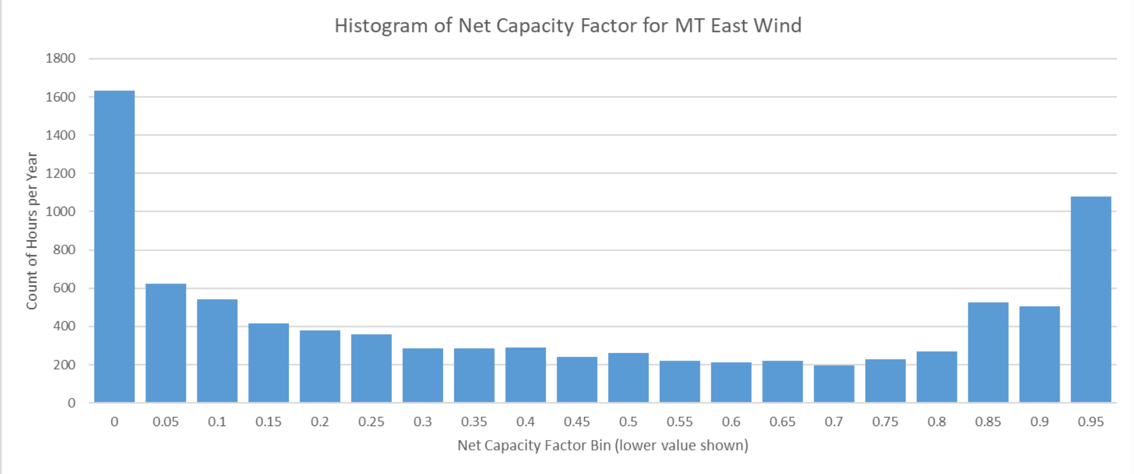
| | | energy is being produced and the time energy is curtailed. The analysis presented needs that data to be credible.<br>If the analysis does prove to be correct will PSE set its level of firm transmission required for wind and solar resources at 90% as the analysis shows? This would increase the amount of actual transmission capacity at all times other than when the generation was occurring at nameplate capacity. It would allow an increase in the nameplate capacity of renewable resources dependent on limited transmission. For example, it would permit the MT wind capacity to be increased to 750MW / 90% = 833MW of nameplate capacity.<br>It also seems like a small amount of storage equal to the overcapacity curtailed by less-than-100% firm transmission would be attractive. It would increase the amount of actual transmission in a transmission line with limited capacity. Has PSE evaluated this? |  <br>You suggest a transmission model where the transmission capacity is scaled up and down with short term, non-firm transmission to meet periods of nameplate power generation. Considering the rapid development of desirable wind locations, it is unlikely that short-term, non-firm transmission would become available in situations where the wind is generating at nameplate capacity. Other projects are likely to have fully subscribed firm transmission in these 'peak generation' events. Furthermore, flexible transmission strategies such as the one described are extremely difficult to model with existing model frameworks. More time will be required to consider how to approach modeling a flexible transmission strategy as described.<br>You also mention a hybrid wind-storage option to limit to allow for reduced transmission capacity. PSE has performed some initial assessments into shared transmission of co-located resources which suggests that there is strong potential for cost savings. Not only with wind-storage hybrids but also wind-solar hybrids. However, again, it will take time to incorporate complex transmission sharing strategies into existing IRP modeling frameworks. Please look for shared transmission of co-located resources in future IRP cycles. |
| 12/26/ 2020 | Willard Westre, Union of Concerned Scientists | Slide 37 - - I disagree that ELCC will be reduced. I believe additional resource builds will be enabled maintaining the ELCC, by more effectively using existing transmission which will allow the lower cost wind resources (with higher ELCC and previously limited by transmission capacity) to replace higher cost resources and resources with transmission build costs and result in lower overall cost. Will PSE please consider this? | As mentioned in the presentation, PSE understands that there may be specific situations where overbuilding the nameplate capacity of a resources as compared to the available transmission may be beneficial to the portfolio. PSE does not believe the IRP is the correct venue for these specific analyses to occur, instead these options should be considered during the resource acquisition process.<br>Generally speaking, a wind resource constrained by transmission capacity less than the nameplate of the facility, and therefore unable to deliver a significant quantity of energy to the grid, will have a lower ELCC than the same resource with firm transmission capacity equal to the nameplate capacity of the resource. Therefore, more resources must be constructed, which carry with them a large annual revenue requirement for the capital cost of the additional resource capacity. In most cases, this large capital revenue requirement, far outpaces the cost of firm transmission. For example, eastern Washington wind has a firm transmission cost of $33/kW-yr and an annual, capital revenue requirement of approximately $140/kW-yr.<br>Specific scenarios such as maximizing generation around a constrained transmission resource such as the Colstrip line, may have different outcomes with improved benefits for the portfolio. But again, PSE believes these benefits should be explored in the acquisition of specific resources and not applied to generic resources assumptions within the IRP modeling process. |
| 12/27/ 2020 | Virginia Lohr, Vashon Climate Action Group | PSE is not responding to what many stakeholders have been asking them to do in regard to how they use the social cost of carbon (SCC). We heard from Irena Netik in Webinar 5 on the Social Cost of Carbon that discussions between PSE and stakeholders on how to handle SCC began during the 2019 IRP process. They began in the very first meeting of the 2019 IRP (the May 30, 2018 meeting PSE unexpectedly moved to Olympia). These "discussions" continued over the course of the 2019 IRP and began again in the 2021 IRP. To hear Elizabeth Hossner in Webinar 11 characterize what stakeholders are asking for as a "miscommunication" | In the 2019 IPR process, PSE included social cost of greenhouse gases (SCGHG) in the IRP analysis and showed a comparison of the results of different methods of including SCGHG. The presentation that PSE shared with stakeholders is still available online in the Past IRPs tab, December 2019 webinar at the bottom of the page.<br>In this IRP, PSE also plans to include SCGHG and is modeling SCGHG using various methods as requested by stakeholders. PSE conducted outreach to stakeholders on the phone and through e-mail in August during the preliminary discussions of sensitivities in the 2021 IRP. During this time PSE spoke with several stakeholders about Sensitivity I where the SCGHG was treated as an "externality" cost. During this time, the stakeholders confirmed that the externality is defined as a negative cost that is not actually built into the production of a good or service, so this |

| Feedback Form Date | Stakeholder | Comment | PSE Response |
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| | | is distressing. PSE has had years to try to understand what stakeholders are asking for. Why have they failed to do so?<br>A year ago, the Governor issued Directive 19-18 on the assessment of greenhouse gas emissions, stating that "Future risks of climate change depend on decisions made today." For PSE, a year after this Directive was issued, to continue to ignore it and wait for all the rules to be finalized before acting on it is not prudent. The Directive clearly stated that current science must be used, yet PSE continues to rely on outdated numbers from the flawed assessment used for their proposed LNG facility in Tacoma. Why does PSE continue to rely on it for decisions being made today that must be made correctly if we and PSE are to have a viable future?<br>I believe that PSE actually understands what many stakeholders, including Robert Briggs, Charlie Black, Joni Bosh, Doug Howell, Tom Eckman, the Govenor, and others, want them to do. Please demonstrate that this is so by running the analyses requested. Show us that you CEO, who we were told was hired to help PSE reduce greenhouse gas emissions and eliminate fossil fuels, is actually leading the way on this. Use the SCC correctly in your analyses to help you determine the best way to reduce your greenhouse gas emissions prudently. Do this for both the electric and the gas sides of your business. It is not appropriate to think that a gas scenario that flatlines gas for decades is acceptable. All greenhouse gas emissions must stop, not just those for the electric side. For PSE to continue to pretend otherwise is also not prudent. | cost is passed to society and further defined the sensitivity where SCGHG does not apply to the operational level decisions. PSE verbally confirmed over the phone and through e-mail that the SCGHG is applied as a dispatch cost in the long term capacity expansion only where the portfolio decision is made. Once the portfolio decision is made and the SCGHG is not included the final hourly dispatch to simulate real world conditions. Sensitivity I follows the stakeholder input on how to treat SCGHG.<br>https://oohpseirp.blob.core.windows.net/media/Default/2021/meetings/August_11_webinar/Invenergy_comments_PSE%E2%80%99s_Use_of_the_Social_Cost_of_Carbon_as_presented_on_August_11_2020.pdf<br>As PSE committed earlier in the process, PSE will still model the SCGHG as a dispatch cost during the electric power price run and during the hourly dispatch and those results will be available at the February webinar. |
| 12/28/2020 | Kyle Frankiewich, Washington Utilities and Transportation Commission | Questions and comments from presentation. | Thank you for your questions. PSE inserted each item below along with PSE's responses. |
| 12/28/2020 | Kyle Frankiewich, Washington Utilities and Transportation Commission | Slide 13 – The company must demonstrate that its plan reasonably balances the feasibility of acquiring substantial resources In a short timeline (a good argument to acquire resources in advance of the requirement) with the least-reasonable-cost approach to compliance (a good argument to wait until the last year to take full advantage of resource cost trends, especially in renewables and storage). How is the CETA renewable need modeled "as a linear ramp rate"? Does that mean the 80% to 100% requirement is included as a constraint for each year between 2030 and 2045? Has (or will) PSE explored the impacts of a year-by-year constraint approach as compared to two constraints – one for the 2030 requirement and one for 2045? | The linear ramp rate has been included to ensure that the model does not wait until the very last moment to add renewable resources and rather is adding resources along the way as PSE will also be working towards meeting CETA requirements and not waiting until the last year. The linear ramp rate is modeled as an annual minimum energy requirement for each year of the time horizon. If the requirement is only constrained for the years 2030 and 2045, then the model will wait till the last year to all resources to meet the requirement. Because of the declining cost curve, resources added in later years are lower cost than resources added earlier in the time horizon. The objective of the model is to minimize cost, so it will wait to add resources in order to minimize the total portfolio cost. |
| 12/28/2020 | Kyle Frankiewich, Washing | Slides 13 & 14 – Slide 13 shows the amount of renewables PSE forecast it would need to acquire in without DERs, including EE and DR. Slide 14 shows the amount of renewables PSE estimates it would need to acquire under its medium scenario with cost-effective DERs. They do not provide the NPV or Levelized Cost of | Chapter 3 of the draft 2021 IRP addresses the decisions behind the draft preferred portfolio and includes a comparison of costs and builds to the Mid portfolio.<br>PSE will also reach out to the WUTC to clarify our understanding of the question. |

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<tr><td></td><td>ton Utilities and Transportation Commission</td><td>Resource Plan that would satisfy CETA and EIA without DERs. The “value” of DERs is the difference between the cost of the resources needed to meet the “mid” shown in slide 13 versus the resources shown on slide 14. It would be useful to know the NPV or levelized cost of the resources required to meet the mid-scenario shown on Slide 13. Moreover, as we discuss later regarding PSE’s flexibility analysis, this difference still would fully capture the value of EE.</td><td></td></tr>
<tr><td>12/28/2020</td><td>Kyle Frankiewich, Washington Utilities and Transportation Commission</td><td>Slide 18 – Staff echoes Participant Adcock’s question and concern regarding the use of a California carbon price as a reasonable cost estimate for alternative compliance mechanisms under CETA. Why is this proxy cost estimate appropriate? Is there any connection to be found between the CA carbon market and the various paths to compliance described in CETA, such as energy transformation projects? In its 2017 acknowledgement letter, the Commission encouraged the company to further develop a marginal abatement cost curve, which could help the company and stakeholders more easily compare various compliance approaches.</td><td><p>PSE first discussed the alternative compliance costs and consulted with stakeholders at the September 1 webinar. PSE requested feedback from stakeholders regarding prioritization of the options for the 20% alternative compliance to reach carbon neutral target by 2030 in the 2021 IRP.</p>
<p>PSE received one suggestion regarding this through the feedback forms.</p>
<p>Feedback from Joni Bosch, NWEC:</p>
<p>In response to the question posed on prioritizing options for the 20% alternative compliance actions that might be addressed in the 2021 IRP, NWEC would urge PSE to model an aggressive amount of conservation and demand response. Beyond the required conservation and demand response required in sections .040 and .050 of CETA, additional innovative conservation, efficiency, storage and demand response should be considered for Energy Transformation Projects. Exploring those has the double impact of further reducing/managing load and achieving additional GHG reductions.</p>
<p>PSE created a portfolio that increased demand response, storage and distributed resources as Sensitivity V and W.</p>
<p>For the baseline assumption and comparison, PSE wanted to use a price forecast for the alternative compliance costs. PSE feels that the California carbon price is a reasonable assumption, however we are open for discussion and can also run another cost forecast to get a range of the alternative compliance costs.</p></td></tr>
<tr><td>12/28/2020</td><td>Kyle Frankiewich, Washington Utilities and Transportation Commission</td><td>Slides 19, 20 & 21 – These slides compare the amount of peak capacity needed with and without EE and DR and the amount of each resource developed by year. Based on our math from the info on the slides, it looks like the model acquires 476 aMW over the first 10 years. In the first few years the model (apparently due to ramp rate constraint assumptions) is acquiring fewer aMW than PSE’s current program actuals, and below what would be required under EIA’s “pro-rata” provision (i.e., 20% of 10 year cost-effective potential each biennium). We understand that PSE intends to run a “six year” ramp in sensitivity for conservation rather the 10-year ramp currently assumed in their modeling, but it seems that this “sensitivity” assumption is more in line with PSE’s current capabilities to acquire conservation, so may be a more reasonable baseline. This six year ramp will also slightly (75-80 MW) decrease the need for additional peak capacity in 2027. It appears that for every aMW of conservation savings PSE acquires it also gets around 1.8 MW of winter peaking capacity (209 aMW of conservation by 2027 reduces peak demands from 907 MW to 527 MW or 380 MW/209 aMW = 1.81 MW/aMW).</td><td><p>The model selected bundle 10 in the mid scenario, and the distribution efficiency, both of which are used in setting the program targets. The draft results for the 2 year ramped and 2 year pro-rata share of the 2021 IRP are shown below in comparison to the 2020-21 program targets:</p>
<table>
<tr><th>Compare 2021 IRP to 2020-21 Program Targets</th><th>2 year</th><th>2 year pro-rata share</th></tr>
<tr><td>Mid Scenario Cost Effective EE, aMW</td><td>42.37</td><td>54.59</td></tr>
<tr><td>Current 2020-2021 Targets</td><td>NA</td><td>54.40</td></tr>
</table>
<p><em>NOTE: The 2-year pro-rata share savings are obtained by dividing the 10-year savings by 5.</em></p>
<p>The 6-year ramp sensitivity results will be available with the final IRP. When compared to the Mid Scenario, the 6-year ramp will likely result in a higher 2-year number but the 2-year pro-rata share number will not change, since it’s the same 10-year savings being implemented at a faster pace over 6 years. From a peak contribution perspective the 6-year ramp does provide peak savings at a faster pace as well.</p></td></tr>
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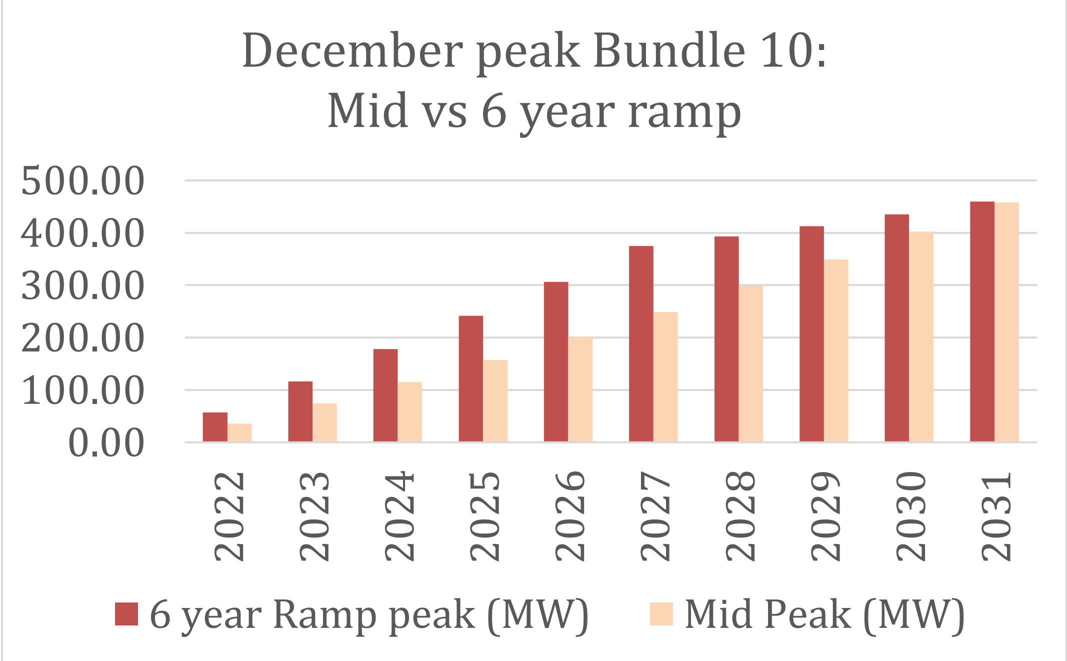
| | | |  |
| 12/28/2020 | Kyle Frankiewich, Washington Utilities and Transportation Commission | Slide 23 – While this slide gives a view into PSE's economic dispatch, rather than PSE's owned or controlled capacity available, it illustrates that PSE is exposed to significant market risk during winter peak periods (gray area in chart), and that increased adoption of DR and other DERs would likely have additional risk mitigation value. PSE will not be completing its risk analysis until after it files it draft IRP in early January. This means than any conclusions it draws regarding the value of DR, DERs or battery storage in the draft IRP should be heavily caveated. | Thank you for your feedback. PSE will complete the market risk analysis for the final IRP |
| 12/28/2020 | Kyle Frankiewich, Washington Utilities and Transportation Commission | Slide 28 – Staff have expressed concern that PSE has only one conservation supply curve that is used across all economic forecast scenarios. This has the effect of overstating conservation potential in the low case and understating potential in the high case, even accounting for differences in the "cost-effectiveness" limit for these scenarios. While PSE has stated that the difference in available conservation among the low, mid and high load forecasts is small, staff understands that the NWPCC's methodology has always included potential assessments that are internally consistent with the load forecast being used to identify resource need. Further, it seems to staff that this would not necessitate three separate CPAs or countless hours of consultant or employee time. If PSE holds separate the "lost-opportunity" conservation measures from retrofits, then scales the lost-opportunity potential to the some of the underlying inputs to the load forecast, such as population and employment growth, that should enable conservation resource options that 'match' a given load forecast. With this caveat, | Thank you for the comment. What you suggest is exactly how the supply curve would be adjusted. The impacts from the low and high load forecasts will translate to the lost opportunity measures in the CPA. In the 2021 IRP most stakeholders are inclined to think that the high load scenario is less likely, hence the results we have for the Mid Scenario have the highest likelihood of being the optimal amount. Thus while we could get higher savings in the supply curve associated with the high scenario, if we were to adjust the CPA, it would likely not impact the cost effective amount of conservation for the preferred portfolio. We agree that the results "across the range of load forecast seem reasonable." There will likely be impact on the resource mix in the high scenario, so we think it could be something to pursue in the next IRP. |

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| | | staff believes the results shared in this presentation across the range of load forecast seem reasonable. | |
| 12/28/2020 | Kyle Frankiewich, Washington Utilities and Transportation Commission | Slide 32 - It appears that through about 2030 the difference in cost between the “mid-case” and this renewables over-generation case is negligible. If so, PSE has several IRP cycles to assess whether storage technology has improved and/or costs have declined before it needs to make a decision about whether to “over-generate and store locally” or sell into the market. Staff looks forward to the market-risk analysis, which will inform the company’s understanding of the how to best balance risks related to storage costs, market costs and market availability for both oversupply events and peak demand events. Staff wonders how far storage costs would have to decline - or how volatile the spot market might become - by 2030 such that a strategy to over-generate and store locally might become cost-competitive or valuable as a risk mitigation option. | Thank you for your comments. |
| 12/28/2020 | Kyle Frankiewich, Washington Utilities and Transportation Commission | Slide 37 – Has PSE explored how this Tx-as-%-of-nameplate idea might interact with energy storage sited at a project? It may lower the maximum available energy in a given hour, but the ELCC calculation and the added dispatchability may more than offset the lowered maximum capacity value and the energy value otherwise thrown away with a curtailment. | PSE already includes several hybrid generic resources which combine a generating resource (e.g. solar or wind) with a storage resource (e.g. battery or pumped hydroelectric storage). These hybrid resources assume the storage resource may only be charged from the ‘attached’ generating resource. The model assumes firm transmission capacity for the hybrid resource is equal to the nameplate capacity of the generating resource only, given it is unlikely both the generating resource and storage resource would need to discharge at the same time. Hybrid resources do have higher ELCC values than a comparable standalone generating resource.<br>PSE has also started to explore the possibility of co-located resources, such as solar and wind located at the same site. Initial work indicates that complementary resource shapes of co-located resources may result in opportunities for reduced firm transmission capacity. PSE aims to expand this analysis in future to include co-located generating resources with independent storage resources (i.e. storage which may charge from the grid). Co-located resources present a significant modeling challenge but PSE hopes to include them in future IRP cycles. |
| 12/28/2020 | Kyle Frankiewich, Washington Utilities and Transportation Commission | Slides 38 – 40 – While staff appreciates this modeling exercise and believes the similarities in the portfolios are interesting, we note that the differences between the two portfolios’ resource additions prior to 2025 are significant. We still struggle with what the inclusion of SCGHG “as an externality” means in the context of the LTCE model, and how this differs from the other two approaches discussed – as a fixed-cost adder and as a dispatch cost. Staff looks forward to reviewing the sensitivity results for a portfolio optimized around the SCGHG as included in hourly dispatch. | SCGHG as a dispatch cost will be included in the final IRP. |
| 12/28/2020 | Kyle Frankiewich, Washington Utilities and Transportation | Slide 42 – The ELCC estimate for batteries feels quite low, though that is purely a ‘gut reaction.’ It makes sense that, if the weather events that drive PSE’s peak capacity needs are more than four hours long, an ELCC calculation for a four-hour duration resource would be low. It also makes intuitive sense that ELCC estimates decrease incrementally for each new wind and solar resource. Would the inverse be true for each incremental battery resource? That is, if PSE adds eight 100 MW bundles of battery resources sequentially, would the ELCC estimate for the ninth bundle of batteries be better, given that 800 MW of batteries has reduced the system’s peak need? | The number 12.4% was achieved from the resource adequacy model, which has more constraints. In the resource adequacy model, the ELCC of the battery could be up to 40%. In the 2021 IRP process, PSE only has the info for 100 MW capacity so far. In 2019 IRP, the ELCC of the battery went down with the increase of the capacity.<br>*Figure 7-19: Peak Capacity Credit for Battery Storage Based on EUE at 5% LOLP*<br>**BATTERY STORAGE**<br>**Capacity (MW)**<br>**2021 IRP Year 2027**<br>**2021 IRP Year 2031** |

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<tr><td></td><td>Commission</td><td></td><td>
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<tr><td><b>Lithium-ion, 2 hr, 82% RT efficiency</b></td><td>100</td><td>12.4%</td><td>15.8%</td></tr>
<tr><td><b>Lithium-lin, 4 hr, 87% RT efficiency</b></td><td>100</td><td>24.8%</td><td>29.8%</td></tr>
<tr><td><b>Flow, 4 hr, 73% RT efficiency</b></td><td>100</td><td>22.2%</td><td>27.4%</td></tr>
<tr><td><b>Flow, 6 hr, 73% RT efficiency</b></td><td>100</td><td>29.8%</td><td>35.6%</td></tr>
<tr><td><b>Pumped Storage, 8 hr, 80% RT efficiency</b></td><td>100</td><td>37.2%</td><td>43.8%</td></tr>
</table>
</td></tr>
<tr><td>12/28/2020</td><td>Kyle Frankiewich, Washington Utilities and Transportation Commission</td><td>Slide 42 – The ELCC estimate for batteries feels quite low, though that is purely a ‘gut reaction.’ It makes sense that, if the weather events that drive PSE’s peak capacity needs are more than four hours long, an ELCC calculation for a four-hour duration resource would be low. It also makes intuitive sense that ELCC estimates decrease incrementally for each new wind and solar resource. Would the inverse be true for each incremental battery resource? That is, if PSE adds eight 100 MW bundles of battery resources sequentially, would the ELCC estimate for the ninth bundle of batteries be better, given that 800 MW of batteries has reduced the system’s peak need?</td><td>Please see response provided directly above.</td></tr>
<tr><td>12/28/2020</td><td>Kyle Frankiewich, Washington Utilities and Transportation Commission</td><td>Slide 46 – This cost breakout is useful. Staff would appreciate the added context of the SCGHG coming from emissions associated with the “No CETA” portfolio. Please also provide these cost comparisons at the 4-yr (CEIP) and through-2030 timescales, as it would be useful to understand whether the cost differences are driven by resources acquisitions in the earlier or later years. The table format in slide 48 is also well-done.</td><td>Part 1: The 24-year levelized SCGHG costs from emissions associated with the “No CETA” portfolio is $9.56 billion dollars. Below is a table showing the 24-year levelized costs comparisons for the Mid Scenario, SCGHG Only No CETA, No CETA, and No CETA with SCGHG costs portfolios.
<table>
<tr><th rowspan="2">Portfolio</th><th colspan="3">24-yr Levelized Cost ($ Billions)</th></tr>
<tr><th>Revenue Requirement</th><th>SCHGH adder</th><th>Total</th></tr>
<tr><td>1. Mid</td><td>$13.60</td><td>$5.00</td><td>$18.70</td></tr>
<tr><td>S. SCGHG Only, No CETA</td><td>$10.10</td><td>$9.00</td><td>$19.10</td></tr>
<tr><td>T. No CETA</td><td>$9.40</td><td>$0.00</td><td>$9.40</td></tr>
<tr><td>T2. No CETA - with SCGHG Costs</td><td>$9.40</td><td>$9.56</td><td>$18.96</td></tr>
</table>
Part 2: The cost comparisons at the 4-yr (CEIP) and through-2030 timescales will be provided in the consultation update.</td></tr>
</table>

| Feedback Form Date | Stakeholder | Comment | PSE Response |
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| 12/28/2020 | Kyle Frankiewich, Washington Utilities and Transportation Commission | Slides 52-62 – Staff is not yet assured that PSE's analysis fully captures the benefit of EE's impact on the amount of the balancing reserves needed, therefore the cost of those reserves. As shown on slide 55, under PSE's mid forecast they estimate they need (@ 99% error) 190 MW of flex-up and 196 MW of flex-down to balance 875 MW of wind in 2025. By 2030 this increases to 695 MW of flex-up and 749 MW of flex-down to balance 2,375 MW of wind and 1400 MW of solar. PSE's analytical results translate mean that for every 100 MW renewable capacity they add between 2025 and 2030 they need to increase their balancing reserves by just over 17 MW flex-up and 19 MW flex-down. Therefore, when EE reduces the amount of renewables required to meet the 80% CETA requirement by 2030 it also offsets the need to increase balancing reserves. When PSE feels comfortable with its estimates of the cost of provide flexible/balancing reserves, staff recommends that the appropriate avoided cost should be subtracted from the cost of the EE bundles such that their "net cost" is seen in AURORA. | The balancing reserve requirement was calculated on the load less conservation. Since the 2021 was not finished at the time, PSE used the 2019 IRP process conservation. |
| 12/28/2020 | Kyle Frankiewich, Washington Utilities and Transportation Commission | Slide 57: the DR resource examined in this flexibility study is useful, but may be a poor proxy for some other flexible demand programs that are likely to be available at scale in Washington in the near future. | For final IRP, PSE will run three different types of DR programs in the flexibility analysis, 1) 40 hour/season, 4- hour duration max with dispatch in real time, 2) 40 hour/season, 4- hour duration max with dispatch in day ahead, and 3) unlimited dispatch. |
| 12/28/2020 | Kyle Frankiewich, Washington Utilities and Transportation Commission | Slide 64: Staff applauds the company's transparency with this initial effort at understanding the value of flexibility. Unfortunately, we do not have any new information to add. The only component that seems relevant that was not discussed through this presentation is the CAISO EIM. The EIM enables participants to balance across a much larger footprint with a greater diversity of variances, thereby lowering costs for all participants. CAISO's EIM has been operating long enough to use its historical pricing information as some sort of ground-truthing of PSE's results. Could PSE glean some better understanding of the value of up- and down ramps by reviewing its participation in the market or analyzing the market's available data? | The flex up and flex down ramp is mimicking the CAISO EIM market, but we can also look to see if CAISO has done any analysis.<br>PSE has also researched PGE's analysis from the 2019 IRP and has been making adjustments. |
| 12/28/2020 | Kyle Frankiewich, Washington Utilities and Transpor | Staff recommendations: | Thank you for your recommendations. PSE inserted each item below along with PSE's responses. |

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| 12/28/2020 | Kyle Frankiewich, Washington Utilities and Transportation Commission | **Proxy cost for CETA alternative compliance approaches: (slide 18)** Staff recommends developing a stronger rationale for using the California carbon market forwards and forecasts as an estimate for CETA compliance alternatives. To the extent that emissions reduction estimates and program costs related to energy transformation projects are estimable at this time, they should be included in the analysis. To the extent that they are not available, the IRP should include an explanation for why, and a timeline for when ETPs will be understood well enough for inclusion. | Thank you for your recommendation. |
| 12/28/2020 | Kyle Frankiewich, Washington Utilities and Transportation Commission | **Market reliance analysis and valuation of demand-side resources: (slide 23)** Staff appreciates that some components of the risk analysis done in an IRP must be undertaken toward the end of the IRP process. Still, PSE's modeling of its transmission rights to the Mid-C market as a firm resource that would serve 25% or more of its peak load highlights that risk. It is unfortunate that this analysis, which has been a topic of consistent interest from the commission, will not be included in the draft IRP, and hence will not benefit from the public participation process connected with the draft IRP. Staff hopes that the value of decreased market reliance risk will be fully considered for those resources that insulate PSE from the cost and reliability risks that come with the company's Mid-C-as-firm-resource modeling assumption. | The market risk analysis will be included in the final IRP |
| 12/28/2020 | Kyle Kyle Frankiewich, Washington Utilities and Transportation Commission | **GHG emissions for all studies: (slide 46-48)** Given CETA's focus on GHG emissions reduction, it would be useful if PSE provided the cumulative GHG gas emissions for each of its cases/sensitivity studies. With this information, the company and stakeholders can compare the various approaches (and cost) of lowering emissions – knowing the $/ton reduction cost may point to alternative compliance mechanisms that are lower cost than reducing GHG from the power system. | PSE included the GHG emission chart in Chapter 8, electric analysis, page 8-23.<br>*Figure 8-10: $CO_2$ Emissions by Portfolio*<br>*(does not include alternative compliance to meet carbon neutral standard in 2030 and beyond)* |

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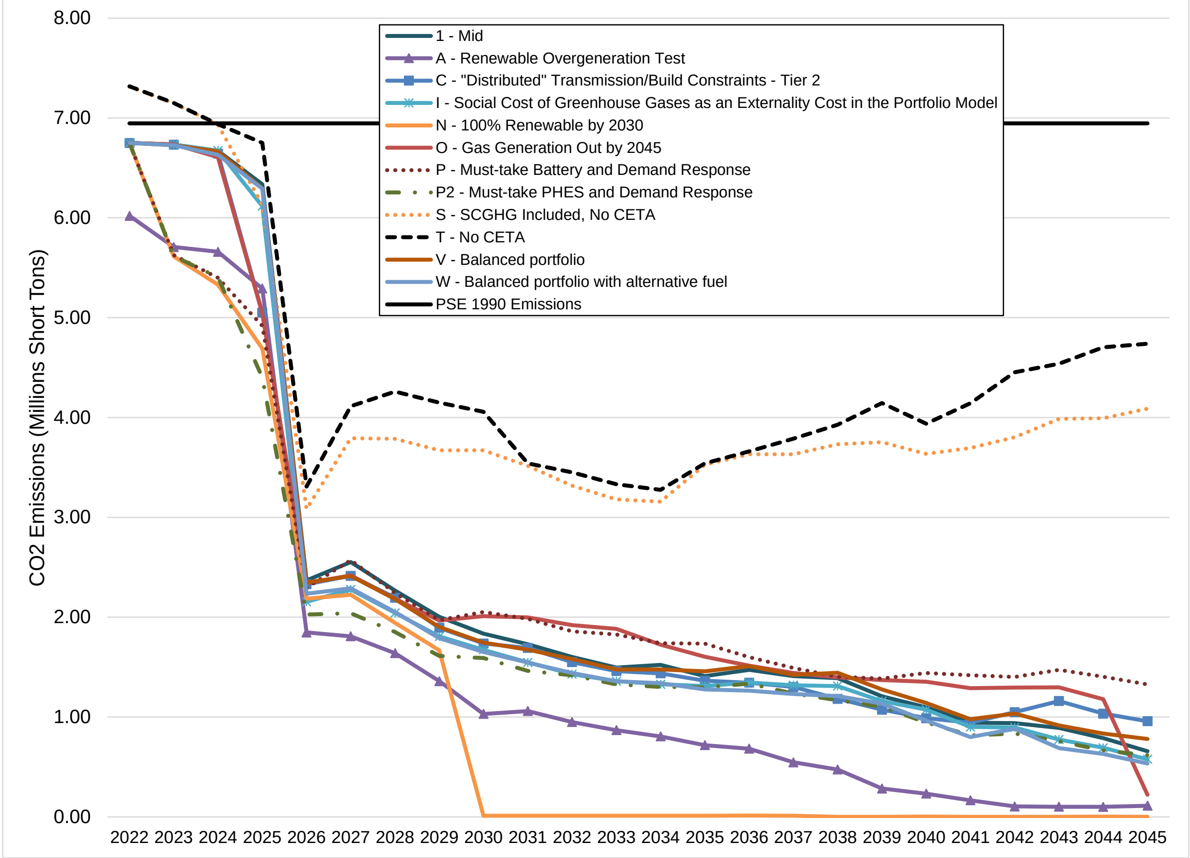
| | | |  <br>PSE will explore the idea of a $/ton reduction cost or carbon abatement curve to use as the alternative compliance cost. |
| 12/28/2020 | Court Olson, Optimum Building Consultants LLC | During the webinar I typed a question into the chat box that was not answered. It related to the chart on slide #22 about flexible peaking capacity. In the narrative next to the chart on that slide is the statement: "The resources shown are the least cost optimization results…" I asked if the social cost of carbon was used in the calculations relating to the least cost depictions there?<br>I had a follow up question in mind that I would like to ask now: What specific cost values were input into the modeling program for each of the different types of resources depicted in the chart on slide 22?<br>Finally, I'd like to hear the details behind how PSE calculated the cost value for the Demand Response resource in the slide 22 chart?<br>I look forward to having these questions answered. | Complete details of all costs for each resource is included in Appendix D of the Draft IRP.<br>Demand response assessment is included in Appendix E. |
| 12/28/2020 | Anne Newcomb | Happy to see conservation is working out so well to reduce costs!<br>On slide 63 or so I appreciate your realization that it would be helpful to bring in some additional experts or council from other utility's who have been successful in | First year of IRP is 2022, given a 2-year construction time for new resources, the first year available is 2024.<br>As a reference, the 2018 RFP was a 2-year process and the new resources have start dates ranging from 2020 – 2023, 2 – 6 years after the start of receiving the bids. |

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| | | the transition to clean energy to assist with analyzing some of the modeling and sensitivity input. Please let me know if you need any help locating someone to help. Considering PSE is behind with running the remaining sensitivities, I suggest hiring energy consultants to help.<br>Getting more renewables online between now and 2025 is important! Why are we waiting? I realize Wind Farms can take 2 years to build and in answering a question at the end of the December 11th IRP, Elizabeth stated PSE would need to wait until 2022 to get started on new wind projects. If the WUTC was to approve the building of more renewable resources like Wind and Solar prior to 2022, would PSE agree to getting started in 2021 with renewable resources from previous RFP's?<br>If we look at all of the stacked benefits of battery storage mentioned by Don Marsh they are a good resource and should be ramped up much faster.<br>No new NG Peakers please! A recent article from Inside Climate News (https://insideclimatenews.org/news/10122020/inside-clean-energy-fossil-fuel-power-plants/ ) has some interesting research showing how if the US doesn't build any new fossil fuel plants to generate electricity there will be very few stranded assets in 2035 when the US may need to generate 100% carbon free electricity under Joe Biden's climate plan. Rather than pay for offsets and stranded assets, lets reduce NG sooner!<br>Hopefully you enjoyed some good time off for the Christmas Holiday! | In October of this year, PSE will be submitting its first clean energy implementation plan (CEIP) for consideration by the Commission, which will include its proposed specific actions and targets with respect to renewable resources. Once the Commission approves the CEIP, PSE can begin acquiring those resources. In the meantime, PSE will continue to look for opportunities to bring new renewable resources online through mechanisms like power purchase agreements to meet identified resource needs.<br>PSE ran sensitivity N, O, P with no new peaking capacity and retiring existing thermal plants. Located in Chapter 8. |