**STATE OF WASHINGTON**
UTILITIES AND TRANSPORTATION COMMISSION
*1300 S. Evergreen Park Dr. S.W., P.O. Box 47250 ● Olympia, Washington 98504-7250*
*(360) 664-1160 ● www.utc.wa.gov*

May 07, 2018

Mr. John Piliaris
Director of State Regulatory Affairs
Puget Sound Energy
10608 Northeast 4th Street
Bellevue, Washington 98009-9734

**Re: Puget Sound Energy's 2017 Electric and Natural Gas Integrated Resource Plan Docket UE-160918 & UG-160919**

Dear Mr. Piliaris:

The Washington Utilities and Transportation Commission (Commission) has reviewed the 2017 Electric and Natural Gas Integrated Resource Plan (IRP) filed by Puget Sound Energy (PSE or Company) on November 14, 2017, and finds that it meets the requirements of Revised Code of Washington (RCW) 19.280.030 and Washington Administrative Code (WAC) 480-100-238.

By acknowledging compliance with statute and rule, the Commission does not signal pre-approval for ratemaking purposes of any course of action identified in the IRP. The Commission will review the prudence of the Company's actions at the time of any future request to recover costs of resources in customer rates. The Commission will reach a prudence determination after giving due weight to the information, analyses, and strategies contained in the Company's IRP along with other relevant evidence.

Because an IRP cannot pinpoint precisely the future actions that will minimize a utility's costs and risks, we expect that the Company will regularly update the assumptions that underlie the analysis within the IRP and adjust its investment strategies accordingly.

The attached document provides specific comments regarding the 2017 IRP and expectations for the 2019 IRP. Please note that with regard to Section III (g), Commissioner Balasbas does not agree with the Commission majority and has written a separate statement.

Sincerely,

MARK L. JOHNSON
Executive Director and Secretary

Attachment - UTC Comments on Puget Sound Energy's 2017 IRP

**Acknowledgment Letter Attachment**
**Puget Sound Energy's 2017 Electric and Natural Gas Integrated Resource Plan**
**Dockets UE-160918 and UG-160919**

## I. Introduction

RCW 19.280.030, WAC 480-100-238, and WAC 480-90-238 direct investor-owned electric and natural gas companies (IOUs) to develop an integrated resource plan (IRP or the Plan) every two years. The IRP must identify "the mix of energy supply resources and conservation that will meet current and future needs at the lowest reasonable cost to the utilities and its ratepayers."[1] The IRP touches every aspect of a company's operations and provides essential public participation opportunities for stakeholders to assist in the development of an effective plan. In preparing an IRP, utilities are required to consider changes and trends in energy markets, resource costs, cost of risks associated with greenhouse gas emissions, state and federal regulatory requirements, and other shifts in the policy and market landscape.[2] The statute and the Washington Utilities and Transportation Commission's (Commission) rules require that IOUs conduct a comprehensive analysis of the costs, benefits, and risks of various approaches to meeting future resource needs using commercially available information. The intent is for each regulated utility to develop a strategic approach that fits its unique situation, while minimizing risks and costs for the company and its ratepayers.

The development of Puget Sound Energy's (PSE or the Company) IRP and involvement of stakeholders and Commission staff (Staff) has been the most extensive such effort in memory. Over the course of the IRP, PSE held 16 meetings with stakeholders and the public. The Company also improved its stakeholder process by hiring an employee to manage its external communications with the advisory group. The Commission acknowledges and appreciates PSE's efforts in this IRP. We also acknowledge the stakeholders and members of the public who participated in the IRP meetings, submitted verbal and written comments, and attended the Commission's recessed open meeting. Their involvement improved the Company's final IRP and the Commission's process.

The Commission determines that Puget Sound Energy's 2017 Electric and Natural Gas IRP complies with the statute and rules governing IRPs and recommends the Company address several areas for improvement in developing its next IRP. In the following sections, we provide comments on the 2017 IRP and identify specific areas for improvement for the 2019 IRP.

## II. Summary of 2017 Electric and Gas Integrated Resource Plan

### *a. Electric Portfolio Summary and Action Plan*

---

[1] RCW 19.280.(9).
[2] RCW 19.280.020(11); WAC 480-100-238(2)(b).

As with the last several of its IRPs, PSE's 20-year load projections in its 2017 IRP are lower than the preceding IRP. After PSE applies demand-side resources, annual average energy demand is expected to increase at 0.4 percent annually, and peak growth at 0.6 percent per year to 5,664 MW in 2037.[3]

***Figure 1: PSE 20-year electric load growth projection 2018-2037***

| | Annual Energy Growth | Annual Peak Growth |
|---|---|---|
| **Before DSR** | 1.7% | 1.6% |
| **After DSR** | 0.4% | 0.6% |

Annual average energy growth is negative (-0.3 percent) for the first 10 years of the IRP, but increases to 1.1 percent per year from 2027 to 2037. Peak demand growth is also flat for the first 10 years, but ticks up to 1.1 percent in the second half of the plan.[4] As will be discussed later, the substantial increase in the latter half of the Plan is due to PSE's assumption that there is no cost-effective retrofit conservation of existing buildings beyond 10 years.

The rate of change of residential electric use per customer is negative after the application of demand-side resources (DSR), therefore, growth is expected to be driven by the increased number of customers.[5] Consistent with economic and population growth trends in the state, the Plan emphasizes that its electric growth is unevenly distributed, with nearly all of the customer growth occurring in its King County service territory.[6]

***Figure 1: PSE 20-year electric load growth projection 2018-2037***

| | Annual Energy Growth | Annual Peak Growth |
|---|---|---|
| **Before DSR** | 1.7% | 1.6% |
| **After DSR** | 0.4% | 0.6% |

PSE's Integrated Resource Planning Solution – its lowest-reasonable-cost portfolio – continues to rely heavily on energy efficiency and market purchases throughout the planning period.[7] Although load growth is slowing, PSE expects significant capacity needs during the 20-year period due, in part, to coal plant retirements and expiring long-term purchase power agreements (PPAs).[8]

[3] Page 5-7 of PSE's 2017 IRP.
[4] Page 5-7 of PSE's 2017 IRP.
[5] Page 5-3 of PSE's 2017 IRP.
[6] Page 5-31 of PSE's 2017 IRP.
[7] The Company does not build an 'Expected Case' or 'Preferred Portfolio' as does Avista and Pacific Power. The Company determines an 'Integrated Resource Planning Solution' as the Company's lowest reasonable cost portfolio from which it builds its Action Plan.
[8] Page 1-12 of PSE's 2017 IRP. The following are identified to be removed from the resource stack: 300 MW from Colstrip Units 1&2 in 2022, 380 MW from Centralia in 2025, 481 MW from Chelan PUD in 2031, and 370 MW from Colstrip Units 3&4 in 2035.

To meet its capacity need over the 20-year horizon, PSE plans to increase its reliance on the Mid-Columbia market hub (Mid-C) for market purchases, by redirecting another 188 MW of available transmission from its wind facilities in southeast Washington to the Mid-C.[9] With this improvement in its ability to use its existing cross-Cascade transmission capacity, the Company will have over 1600 MW of transmission available on which to schedule Mid-C market purchases for meeting peak energy needs.

The Base scenario forecasts that the Company will need 215 MW of additional peaking capacity by 2023.[10] To meet the requirements of the state Energy Independence Act, PSE expects it will need approximately 720,000 qualifying renewable energy credits by 2023, the equivalent of a 227 MW wind project or 266 MW of eastern Washington solar.[11] The Company also intends to acquire 741 MW of conservation over the 20-year period, 148 MW of demand response, and 75 MW of energy storage.

PSE's 2017 Electric Action Plan comprises the following:[12]

- Acquire 374 MW of energy efficiency by 2023.
- Issue a new demand response request for proposal (RFP) based on recent work on the prudence criteria and cost recovery mechanism.
- Install a small-scale flow battery to gain operational experience.
- Issue an all-source RFP in the first quarter of 2018 to meet its renewable and capacity need in 2022.
- Develop options to mitigate risk of relying on the market to meet energy and capacity needs.
- Continue to participate in the Energy Imbalance Market.
- Examine regional transmission needs in the 2019 IRP including re-purposing Colstrip transmission rights.

### b. *Natural Gas Portfolio Summary and Action Plan*

The IRP identifies a natural gas shortfall beginning in the winter of 2018, and then again each year beginning in the winter of 2023.[13] To meet the short-term need in 2018, the IRP states that PSE will contract for short-term firm pipeline capacity to Sumas. Beginning in 2022, the Company will expand the Swarr propane facility.

---

[9] PSE has additional transmission capacity from its wind facilities in southeast Washington because the facilities have not achieved the capacity factor PSE projected at the time the facilities were built. PSE has had to reduce its projected capacity factor twice since the facilities were placed in service.

[10] Page 1-12 of PSE's 2017 IRP.

[11] Page 1-15 of PSE's 2017 IRP. PSE could also use unbundled renewable energy credits to meet some or all of its compliance obligations.

[12] Pages 1-7 – 1-10 of PSE's 2017 IRP.

[13] PSE expects the Tacoma Liquified Natural Gas (LNG) project to be completed by the 2019/2020 heating season providing capacity relief until 2023/2024.

To solve for the gas capacity shortfall, PSE modeled energy efficiency and various supply-side resources. PSE intends to acquire 14 million dekatherms per day (MDth/day) by winter of 2021 and 65 MDth/day by 2033. The IRP finds less conservation than the 2015 IRP due to lower demand forecasts, updated measure savings, and lower natural gas prices.[14] However, PSE increased its estimated achievability from 75 percent to 85 percent relative to the previous IRP. The Plan also finds the Swarr propane facility to be a least-cost resource in most scenarios because upgrading the facility is fully within PSE's ability to control and the Company has the flexibility to "fine-tune" the timing of this resource.[15] This expansion would add 30 MDth/day of capacity.

The Plan states that the Tacoma LNG facility is needed by 2021 in the high-growth scenarios, but under the Base Scenario, it is not needed until 2029. The project would add 16 MDth/day of capacity.

Finally, the Plan assumes the expansion of the Westcoast Pipeline from the Station 2 hub in Canada to the Sumas hub and the Northwest Pipeline from Sumas to PSE's service territory by 2029. The project would initially provide 61 MDth/day of capacity, increasing to 140 MDth/day by winter 2037.[16] PSE notes that this project does not require participation from any other party, unlike other pipeline alternatives.[17]

PSE's 2017 Natural Gas Action Plan includes:[18]

- Acquire 14 MDth per day of energy efficiency by 2022.
- Complete the PSE LNG peaking project by the 2019/2020 heating season.
- Maintain the ability to upgrade the Swarr propane-air injection system for the 2024/2025 heating season.

## III. Comments and Modeling Improvements

PSE's electric and natural gas analysis of its resource needs over the 20-year planning horizon is generally comprehensive, and the Commission is satisfied with the scope of analysis and overall presentation.

An IRP is an iterative process in which the Company regularly updates its assumptions and responds to the external environment. The key inputs in an IRP such as load growth rate forecasts, natural gas prices, and environmental regulation risks, change from year to year. As such, out of each IRP the Commission asks the Company to consider new modeling scenarios

[14] Page 7-37 of PSE's 2017 IRP.
[15] Page 2-26 of PSE's 2017 IRP. Swarr is an extreme peaking facility that mixes propane and air in a ratio that approximates the heat content of pipeline gas.
[16] This option only evaluated an expansion of Northwest Pipeline from Sumas to PSE's service territory; it did not model an expansion on Northwest Pipeline's east-west route through the Columbia Gorge.
[17] Page 7-37 of PSE's 2017 IRP.
[18] Page 1-11 of PSE's 2017 IRP.

and sensitivities, or other improvements in its next Plan. The following section explains the topics and issues on which the Commission would like further analysis.

*a. Continued Reliance on Market Purchases to Meet Peak Needs*

PSE relies on nearly 1,600 MW of wholesale market purchases to meet its energy and peak capacity needs, and expects to increase that reliance in the 20-year plan.[19] Describing the risk of relying on wholesale market purchases, PSE writes that,

> While uncertainties remain, there are also reasons for increased confidence. So, while there is still some level of risk to PSE in relying on wholesale market purchases in order to meet resource need, this risk appears to be significantly reduced from the level presented in the 2015 IRP…[20]

PSE based its assessment on the updated long-term regional resource adequacy (RA) studies performed by the Northwest Power and Conservation Council (Council), the Pacific Northwest Utilities Conference Committee, and the Bonneville Power Administration conducted since the completion of the 2015 IRP. PSE is also more comfortable with its RA position than it was in the 2015 IRP because it shifted back to a 5 percent loss of load probability (LOLP) metric for capacity planning, as opposed to the Value of Lost Load approach in the previous plan.[21]

However, we are concerned that the Company's view of the reduction in risk of relying on the market for capacity at its current level may be unrealistic as part of a utility's preferred portfolio. Beginning after 2000, independent power producers added considerable generation capacity in the Northwest region that went unsubscribed and subsequently became surplus in the region. This provided utilities a temporary opportunity to pursue a least-cost strategy of reliance on the market to complete their capacity needs. The market capacity surplus is now dwindling and it does not appear that independent developers are stepping forward again to build without firm contracts. Both PSE and the Council are increasingly uncertain that there is sufficient RA in the next five years, and therefore a capacity-short position is an increasing possibility.

In demonstrating prudent utility action, PSE is responsible for considering market-volatility risks as a result of not acquiring fixed-cost generation assets or demand-side resources for meeting customer demand. PSE's 20-year resource plan does not necessarily need to show a path to closing out PSE's reliance on the market for its capacity resource needs.[22] As explained in the next section, the Company's continued improvements in its RA analysis is impressive. However, in all three of the RA studies described in the IRP, the direction of RA beyond 2021 is clear: capacity markets are likely to fall short of meeting the RA standards. Unfortunately, the

[19] Appendix G of PSE's 2017 IRP.
[20] Appendix G, p. G-4 of PSE's 2017 IRP.
[21] Page G-4 of PSE's 2017 IRP. Five percent LOLP is the planning standard used by the Northwest Power and Conservation Council.
[22] Pages 6-12, 1-9, and 2-6 of PSE's 2017 IRP.

IRP does not expressly model or address market prices that can result from a tight capacity market.[23]

Such analysis is arguably very difficult to perform in an IRP setting, but both theory and historical experience suggest that demand will be inelastic, leading to very high costs for purchasing capacity from a tight market. Without a firm analysis that can establish a reliable boundary for those potential costs, the absence of a plan for eliminating reliance on market purchases over the 20-year plan carries excessive risk. Therefore, PSE should pursue and model IRP alternatives to its historically heavy reliance on market resources to satisfy medium-term and long-term capacity needs.

*b. Resource Adequacy (RA)*

PSE re-examined its 2015 IRP RA analysis, moving back to the Council's 5 percent LOLP. PSE also examined two other RA metrics, the Expected Unserved Energy (EUE) resource adequacy metric, which is a quantitative measure of the magnitude of load curtailments, and the Loss of Load Expectation (LOLE) metric, also called the Loss of Load Hours (LOLH), which provides information about the duration of the curtailment events.

Each of these metrics provide unique heuristic measures of the failure to serve load. The Commission agrees with PSE's pursuit of the use of EUE and LOLE along with its use of LOLP. Though PSE and others in the industry will need to address how to balance the interpretations of the three unique measurements, the Commission recognizes PSE's leading effort to employ EUE and LOLE.

*c. Colstrip Generating Station*

In its 2011 Acknowledgment Letter, the Commission requested that PSE conduct a broad examination of the cost of continuing the operation of the Colstrip Generating Station over the 20-year planning horizon, including a range of anticipated costs associated with federal Environmental Protection Agency (EPA) regulations on coal-fired generation.[24] It also asked that PSE model a scenario without Colstrip that includes results showing how PSE would choose to meet its load obligations without Colstrip in its portfolio and estimates of the impact on Net Present Value (cost) of its portfolio and rates.

In its 2013 IRP, PSE ran four cases on Colstrip's environmental compliance costs.[25] PSE identified as the most likely scenario Case 2, which assumes Units 1 & 2 must comply with EPA Best Available Retrofit Technology requirements of EPA's Regional Haze Federal Implementation Plan. Under Case 2 conditions, PSE determined that all four Colstrip units

[23] The IRP uses an expansion model that adds capacity resources to prevent capacity shortages from thwarting price formation in the model.
[24] PSE's 2011 Electric and Gas Integrated Resource Plan, Dockets UE-100961 & UG-100960, Attachment: Utilities and Transportation Commission Comments.
[25] See PSE 2013 Integrated Resource Plan, Dockets UE-120767 and UG-120768, pp. 5-41 – 5-55.

would continue to run in six of its 10 scenarios including in its expected Base Case, and Units 3 & 4 continue to run in two of the remaining four.[26] In the Commission's 2013 Acknowledgment Letter, the Commission was unable to conclude that PSE's analysis demonstrated that the continued operation of Colstrip Units 1 & 2 should or should not be a component of the Selected Resource Plan.[27] Since the 2013 IRP, PSE has committed to closing Units 1 & 2 by July, 2022.[28]

In its 2017 IRP, PSE found that the continued operation of Units 3 & 4 is highly dependent upon future environmental regulations, and that a carbon policy would add to the dispatch costs of the units could make the units uneconomical. PSE conducted three sensitivities on how different retirement dates for the four units could affect decisions on what types of resources to replace Colstrip.[29]

The Company's Colstrip sensitivities are a useful exercise to inform itself, the Commission and the public of what types of resources could replace Colstrip Units 1-4 when they close, and at what cost. However, they do not address the economics of continuing to run Units 1 & 2 until July, 2022, and Units 3 & 4 indefinitely.

PSE's IRP does not identify the costs of outstanding liabilities for remediation responsibilities associated with the closure of Colstrip Units 1-4, or how those liabilities might grow with continued operation of the units. Such open-ended liabilities should be accounted for in assessing the monetary risk of operating the units within PSE's portfolio. In its 2017 general rate case, PSE agreed to a settlement to set the depreciation schedule for Units 3 & 4 to December 31, 2027, but did not commit to closing the units at that time.[30] In that case, PSE testified that "$95 million in hydro-related Treasury Grants addresses nearly all of the estimated decommissioning and remediation costs for Colstrip Units 1 & 2," and "remaining PTCs are available to fund additional decommissioning and remediation, if needed, after the $95 million in Treasury Grants has been used."[31] The Company did not estimate decommissioning and remediation costs for Units 3 & 4.

We are deeply concerned with the direct costs of continued operation of Colstrip Units 1-4 and the magnitude of economic risk of continued investment in those units. Nowhere in this IRP does PSE explicitly express or discuss risks imposed on the utility and its ratepayers, including costs of risks associated with Colstrip's fuel source, projected capital investments, and ongoing operational expenses, much less decommissioning and remediation cost assumptions. In the 2019 IRP, the Commission expects PSE to answer the following questions pertaining to Colstrip:

1. Regarding fuel source cost and risk:
    a. How dependent is Colstrip on a single-source mine for its fuel?

---

[26] See PSE 2013 Integrated Resource Plan, Dockets UE-120767 and UG-120768, page 5-46.
[27] PSE's 2013 Electric and Gas Integrated Resource Plan, Dockets UE-120767 and UG-120768, Attachment B: Utilities and Transportation Commission Comments.
[28] Page 1-5 of PSE's 2017 IRP.
[29] Page 4-5 of PSE's 2017 IRP. Sensitivity 1 retires Units 1 & 2 in 2018, Sensitivity 2 retires Units 3 & 4 in 2025, and Sensitivity 3 retires Units 3 & 4 in 2030.
[30] Dockets UE-170033 and UG-170034, Exh. PSE-1JT at 7:6-12.
[31] Dockets UE-170033 and UG-170034, Exh. PSE-1JT at 5:13-6:3.

   b. How well understood is the supply of coal from the Colstrip mine?
      i. What are the financial risks of the type of mining used to extract the existing coal?
      ii. As the need for fuel for Colstrip declines, how does the cost per unit of coal from the Colstrip mine increase?
      iii. What are the counter-party risks of mine operation?
      iv. What risks to coal supply and coal cost does the Joint Colstrip ownership agreement impose? How will PSE manage them?
   c. How does the fuel supply risk from Colstrip compare to that of natural gas?
2. Does PSE have an assessment of the cost related to the counter-party risk of Riverstone ceasing operation of its share of Colstrip Unit 3?[32] If not, why not?
3. Does PSE have an assessment of the cost of the counter-party risk of Riverstone being financially unable or otherwise failing to pay its share of decommissioning and remediation costs for Unit 3?
4. How are the economics of Colstrip Units 1 & 2 and Units 3 & 4 affected if natural gas prices continue to remain relatively flat?
5. What are PSE's best estimates of remediation and decommissioning costs associated with Colstrip Units 3 & 4?
6. Has PSE quantified capacity replacement costs for Colstrip Units 3 & 4 that it could use as a basis of seeking replacement capacity as an alternative to any large capital investments it faces at Colstrip?
7. What is the risk of the failure of a large cost component of Colstrip Units 3 & 4 (such as: the heat exchangers, steam turbine or drive shafts) over PSE's expected 20-year life of the plant?

The economic viability of Colstrip is dependent on the outcome of numerous future events. To properly capture the expected cost of Colstrip over the 20-year horizon of an IRP, the probability of each event needs to be assessed and the cost weighted by its probability of occurrence. This comprehensive approach produces a probability distribution for the set of possible total cost outcomes of the operation of Colstrip over the planning horizon. The Commission recognizes that the approaches to this analysis may vary; however, regardless of the approach used, each utility's resource plan must comprehensively assess all categories of cost and risk, particularly for complex resources like Colstrip Units 3 & 4 that are included in the Plan and future plans. In its next IRP, PSE should assess all categories of operational costs for Colstrip Units 1-4 and explicitly identify the range of possible costs in each category over the expected life of the units. PSE should also identify whether the costs are known or if they are open-ended. If costs are not known and measurable, the risk that such unknowns add to the utility portfolio should be identified by modeling a range of possible costs or other suitable means. As appropriate, the probability needs to be assessed and the cost weighted by its probability of occurrence. The Company's 2019 Plan should clearly and transparently identify cost data and discuss in detail the relationship between the range of these input assumptions, portfolio modeling logic, and the output of the modeling, as well as how the Company used such analysis to choose its Integrated Resource Planning Solution.

[32] Riverstone purchased the assets of Talen Energy.

*d. Resource Cost Assumptions*

The Company's assumptions on the cost and values of new generation resources was a major point of debate throughout the IRP process. PSE contracted Black and Veatch to provide price estimates for generic thermal resources, which showed frame peaking plants dropping 30 percent in price from the 2015 IRP.[33] PSE's own cost analysis for renewable energy generation found relatively modest price decreases. After some members of the advisory group put forth their own cost estimates using non-PSE data, and significant debate within the advisory group, PSE contracted for additional analysis for the cost of generic renewable resources from the consulting firm DNV-GL.[34] PSE took the right step in seeking additional, third-party analysis. However, some stakeholders continued to disagree with PSE's resource assumptions.

Writing on behalf of Sierra Club, Synapse Energy argued that PSE continues to overstate the costs associated with renewable resources and unnecessarily constrains the cumulative development of renewable resources in its portfolio over the planning horizon.[35] Renewable Northwest argued that PSE's assumption that utility scale solar has a capacity contribution of zero percent ignores its contribution to resource adequacy.[36] Multiple stakeholders raised concerns that PSE does not clearly define either the cost or capacity contribution estimates, or continue to express concerns over what they consider to be a lack of transparency about which cost components are included in the construction of the cost of each resource type.[37]

We recognize the Company and the stakeholders for working through this issue to the betterment of the IRP. Although not all members of the stakeholder group are satisfied with the Company's assumptions in the Plan, this type of Advisory Group discussion is necessary. Especially in IRPs that occur long after the Company has received actual cost bids in an all-source RFP, it is important for the Company to ensure it is using the best, commercially available resource costs. Fortunately, PSE will have the all-in cost estimates for many types of generators as a result of its 2018 all-sources RFP. However, if the Company relies on third-parties to provide the latest commercially available information, it is important for the Company to accurately assign generic costs, such as owners cost, to the specific technology as applicable. We also require that the Company present resource costs in a consistent reporting format, and continue to reassess its assumptions for each type of generation resource, including projected costs and year-round and peak capacity valuations.

---

[33] Page 4-32 of PSE's 2017 IRP. Frame peaker NG-only 1x0 capital cost is $639/kW. In the 2015 IRP a frame peaker with oil was $879/kW.
[34] DNV-GL also provided Portland General Electric with its generic renewable resource costs in its latest IRP.
[35] Synapse Energy Economics Inc. Comments on Puget Sound Energy's 2017 Integrated Resource Plan, pp. 1-2, 6-11.
[36] Comments of Renewable Northwest, p. 5.
[37] Comments of Orion Renewable Energy Group LLC, Comments from Invenergy LLC, Comments of Renewable Northwest, Comments from the Northwest Energy Coalition, Comments from Synapse Energy Economics Inc. prepared for Sierra Club, and Comments from Climate Solutions.

### *e. Energize Eastside*

At the request of stakeholders, PSE provided studies in support of the reliability need it identified and potential alternative solutions to the Energize Eastside Project.[38] However, we heard from Staff and some stakeholders that PSE would not discuss these studies in the advisory group, and therefore left unresolved some basic questions about the studies' assumptions, methodologies, and conclusions. For example, the Plan does not include a narrative regarding:

- The effect of the power flows due to entitlement returns on the need for the Energize Eastside Project.[39]
- The reason for, and effect on the need for the Energize Eastside Project, of modeling zero output from five of PSE's Westside thermal generation facilities.
- PSE's choice not to provide modeling data to stakeholders with Critical Energy Infrastructure Information clearance from FERC.
- Resolution of the effect of lower load assumptions on the need for Energize Eastside Project.

The IRP process is specifically structured to allow public discussion and inquiry, including a thorough examination of the analysis supporting a conclusion of need. This is an area in which we would like to see more engagement from the Company.

In describing the status of the Energize Eastside Project with respect to its 2017 IRP, PSE states, "the needs assessment and solution identification phases of this project have been completed. Currently, the project is in the route selection and permitting phases."[40] WAC 480-100-238(3)(d) requires an integrated resource plan to include "[a]n assessment of transmission system capability and reliability, to the extent such information can be provided consistent with applicable laws." The Company has an obligation to bring major transmission investments into the IRP for examination. The Company complied with the letter of the law in Chapter 8 where it provided a history of its Needs Assessment Reports. However, the Plan did not answer many questions that are needed for determining if the Company's conclusions are justified. For instance, it is still not clear if a joint utility analysis of all available transmission and potential interconnections in the Puget Sound region might solve the Energize Eastside reliability issues. Whether PSE has engaged in such analysis or discussions remains unclear and would have been better answered in the IRP.

### *f. Load Growth and the Effects of Conservation*

PSE's forecasted increase in its annual energy and peak load growth over its 20-year planning horizon are due entirely to growth forecasted in the second half of the 20-year plan. As Staff

---

[38] Page 8-34 of PSE's 2017 IRP.

[39] Entitlement returns refers to the obligation of the United States to return a certain amount of power back to Canada as part of the Columbia River Treaty.

[40] Page 8-30 of PSE's 2017 IRP.

notes in its comments, historically, PSE's load forecasts have been overly optimistic. This was highlighted in a study by the Lawrence Berkeley National Laboratory of utility average annual growth rate of energy (AAGR).[41]

***Figure 2: PSE's projected and actual average annual growth rate of electric energy***

| Period | PSE Projected AAGR | PSE Actual AAGR |
|---|---|---|
| **2006-2014** | 1.75% | -0.19% |
| **2012-2014** | 1.90% | -1.19% |

The 2017 IRP projects flat to negative annual growth rates for the first 10 years of the Plan when there is projected aggressive energy conservation.[42] PSE models the first 10 years of conservation by applying 20 years of retrofit conservation measures from the conservation potential assessment (CPA) into the first 10 years of the IRP.[43] This and prior IRPs have shown the advantages of this compressed conservation schedule as it provides both a more cost-effective conservation portfolio and a reduction in PSE's revenue requirement. The acceleration of conservation is not unreasonable because the CPA relies on average regional conservation uptake rates that are normally exceeded by PSE's conservation performance. Furthermore, PSE has a history of aggressive conservation and the ability to achieve its targets has been demonstrated in every biennial conservation target to date.

However, the only conservation remaining in PSE's IRP model in years 11 through 20 are measures that are replaced on "burn-out" or new construction, with zero contributions from retrofit conservation measures. This lack of any retrofit conservation in the later years significantly affects the energy demand and therefore the projected need for new resources beyond year 10. PSE makes the same assumption for its natural gas demand forecasts and retrofit conservation. We agree with Staff's comments that PSE should assume in years 11 through 20 that a reasonable level of emerging retrofit conservation measures will become available in the market at cost-effective rates even though they cannot be accurately identified or predicted now.[44] This has been the experience in the region for more than three decades.

*g. Greenhouse Gas Regulation and Carbon Price*

Both State statute and Commission rule require an electric utility's expected case to represent the lowest reasonable cost, which includes "public policies regarding resource preference adopted by Washington state or the federal government, and the cost of risks associated with environmental effects including emissions of carbon dioxide."[45] That is, the Company must consider both known regulatory costs and the risk of future costs.

---

[41] Laurence Berkeley National Lab, "Load Forecasting in Electric Utility Integrated Resource Planning," October 2016, p. 25. https://emp.lbl.gov/publications/load-forecasting-electric-utility
[42] Page 5-8 of PSE's 2017 IRP.
[43] Appendix J of the IRP, Conservation Potential Assessment, pp. 16 and 45.
[44] Dockets UE-160918 and UG-160919 Staff Comments on PSE's 2017 Electric and Natural Gas IRP, pp. 9-10.
[45] WAC 480-100-238(2)(b).

Since the 2015 IRP, there have been significant changes to greenhouse gas emissions regulations, including increases to the renewable portfolio standards in California and Oregon, possible repeal and replacement of the Clean Power Plan (CPP), the implementation of Washington's Clean Air Rule (CAR), and now the rule's legal ambiguity. Despite the uncertainty surrounding the CPP and the CAR, there continues to be considerable legislative and regulatory risk associated with greenhouse gas emissions. In the last two years at the Washington State legislature, more than a dozen bills were introduced that would impose a cost on greenhouse gas emissions, or place limits on emissions.[46] Voters rejected a carbon tax at the ballot in 2016,[47] but another initiative has been filed, which may appear on the ballot in November 2018.[48] Additionally, Washington state and the federal government are in litigation by parties seeking regulation of the impacts of fossil fuels.[49] Local governments throughout PSE's service territory have established public policies to address climate change through aggressive greenhouse gas reduction goals.[50] Dozens of citizens testified concerning PSE's IRP at the Commission's public hearing arguing that their local public policies should be more fully recognized in PSE's next IRP.

Public policy is driving continued uncertainties in carbon policy, which exemplify the shifting regulatory terrain challenging the Company's planning efforts. In this environment, it is imperative that utility planners recognize the risks and uncertainties associated with greenhouse gas emissions and identify a reasonable, cost-effective approach to addressing them.

In its Base Scenario, PSE models the CAR regulations applying to both electric and gas utilities, the CPP across the Western Interconnection, and in-state resources transitioning from CAR to the CPP in 2022.[51] Both the CAR and CPP only applied to combined-cycle combustion turbines (CCCTs) and not to natural gas peaking plants. PSE concludes that the implied cost of carbon regulation is $27/metric ton. PSE runs seven Base Case Scenarios with different carbon regulations in its IRP, described as Scenarios 1, 9-14.[52]

The IRP is not clear on which set of carbon regulations is informing the Company's electric

---

[46] *See,* e.g. HB 1144, HB 1155, HB 1646, HB 2230, HB 2839, SHB 2995, SB 5127, SB 5385, SB 5509, SB 5930, SB 6096, SB 6203, SB 6335, and SB 6629.

[47] Washington Carbon Emission Tax and Sales Tax Reduction, Initiative 732.

[48] Seattle Times, "New Washington initiative would put fee on carbon emissions", March 2, 2018. https://www.seattletimes.com/seattle-news/environment/new-washington-initiative-would-put-fee-on-carbon-emissions/.

[49] Associated Press, "Activists Sue Washington State for Tougher Climate Policy", February 16, 2018. https://www.usnews.com/news/best-states/washington/articles/2018-02-16/activists-sue-washington-state-for-tougher-climate-policym. , and Bloomberg, "Teenagers Defeat Trump's Move to Kill Climate Change Lawsuit", March 7, 2018. https://www.bloomberg.com/news/articles/2018-03-07/youths-defeat-trump-s-move-to-kill-climate-change-lawsuit.

[50] *See* Whatcom County, http://www.whatcomcounty.us/documentcenter/view/31641; Pierce County, http://www.co.pierce.wa.us/5558/Climate-Change-Resilience; King County, https://www.kingcounty.gov/services/environment/climate/strategies/strategic-climate-action-plan.aspx; and Thurston County, http://www.co.thurston.wa.us/planning/climate/climate_program.htm

[51] Page 4-3 of PSE's 2017 IRP.

[52] Page 4-3 of PSE's 2017 IRP.

resource action plan. Although for most of the Action Plan PSE appears to be using the carbon regulation in Base Case 1, which applies a carbon price to CCCTs and not peakers, it also states that it intends to acquire demand response using results from the comparison between Scenarios 9 and 14, which apply no carbon price and a carbon price to all thermal plants.[53] We are concerned with the lack of clarity in the Plan regarding how PSE used the Scenarios to decide its Integrated Resource Planning Solution.

RCW 19.280.030(f) requires utilities to prepare a long term plan that identifies the near term and future needs at the lowest reasonable cost and risk to the utility and its ratepayers. The term lowest reasonable cost means the utility must consider "the risks imposed on the utility and its ratepayers, public policies regarding resource preference adopted by Washington state or the federal government, and the cost of risks associated with environmental effects including emissions of carbon dioxide."[54]

By only modelling existing state regulation in its preferred portfolio, the Company's price of carbon does not consider the complete risk of additional regulation and, as such, risks not meeting statutory requirements. In future IRPs, PSE should incorporate the cost of risk of future greenhouse gas regulation in addition to known regulations when it develops its Integrated Resource Planning Solution. This cost estimate should come from a comprehensive, peer-reviewed estimate of the monetary cost of climate change damages, produced by a reputable organization. We suggest using the Interagency Working Group on Social Cost of Greenhouse Gases estimate with a three percent discount rate.[55] PSE should also continue to model other higher and lower cost estimates to understand how the resource portfolio changes based on these costs.[56]

*h. Modelling Greenhouse Gas Abatement Costs*

As a condition of extending the Company's IRP submittal due date, the Commission approved PSE's proposal to model the cost of available greenhouse gas abatement options.[57] Through the adoption of the Clean Air Rule, and numerous policy level proposals at the legislature, it is likely that utilities will be required to lower emissions from utility operation. A marginal abatement cost curve (MACC) is a tool that helps identify the lowest-cost options for reducing greenhouse gases.

---

[53] Scenario 9 has no carbon price on any resource. Scenario 14 applies a carbon price to all resources.
[54] RCW 19.280.020(11).
[55] *See* Technical Support Document:-Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis – Under Executive Order 12866- Interagency Working Group on Social Cost of Greenhouse Gases, United States Government. August, 2016. https://www.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf.
[56] For example, for complying with Washington state Executive Order 14-04, the Washington State Energy Office recommends state agencies use the Interagency Working Group on Social Cost of Greenhouse Gases estimate with a 2.5 percent discount rate.
[57] Dockets UE-160918 & UG-160919, Order 01, ¶5.

We applaud PSE for being the first investor-owned utility in Washington to develop and publish a MACC in its IRP. It is important for policymakers to have this type of information available as they continue to consider policy options to lower greenhouse gas emissions. As Commission Staff states in its comments, there are ways for PSE to improve upon its MACC.[58] At this time, the MACC is best at ranking resource choices that best reduce emissions rather than as a source for the actual dollar impact. We expect that this type of information will be highly sought after by policymakers, and we urge PSE to continue working with Commission Staff, stakeholders, and academic experts to refine its MACC.

i. *Conservation*

In all 14 scenarios in PSE's IRP, the Company expects to purchase the same quantity of conservation regardless of the other inputs, such as low or high natural gas prices, or the application of a carbon tax.[59] PSE's analysis in Chapter 6 also shows that a lower discount rate for residential conservation does not have a material impact on the amount of conservation purchased. Both of these outcomes seem implausible.

In its comments, Staff recommends that PSE create smaller electric conservation bundles particularly around anticipated cost-effectiveness price points for smaller groups of individual measures. Alternatively, Staff recommends that PSE model individual measures separately to determine more accurately the amount of cost-effective conservation available. Finally, Staff recommends that PSE examine the effect of a lower discount rate for residential conservation in the 2019 IRP.[60]

The Company should work with Staff, its Conservation Resources Advisory Group, and the Council to refine its conservation bundling. The Company should also use a lower discount rate for residential conservation in the Base Case as it is a more accurate representation of the opportunity cost of capital and the risk of the investment for the customers who are choosing to purchase energy efficiency.

*j. Gas Peak Day Load Forecast*

PSE design peak day used in this plan is a 52 heating degree-day, which equates to 13 degrees Fahrenheit average temperature for the day.[61] PSE adopted this standard in its 2005 Least Cost

[58] Dockets UE-160918 and UG-160919 Staff Comments on PSE's 2017 Electric and Natural Gas IRP, pp. 13-14.
[59] Page 2-7, figure 2-4 of PSE's 2017 IRP.
[60] Docket UG-121207, Policy Statement on the Evaluation of the Cost-Effectiveness of Natural Gas Conservation Programs, "For residential participants, the upfront costs are often small enough so as not to require long-term financing. Accordingly, residential programs evaluated under the TRC should use a discount rate reflective of minimal financing needs and low risk. We determine that the interest rate of U.S. Treasury notes is a reasonable indicator of low-risk investments."
[61] IRP Appendix E, E-12.

Plan, which was the forerunner to the IRP. Staff recommends that PSE consider revisiting its peak gas day standard in the next IRP to see if it needs to be updated.[62]

*k. Tacoma LNG facility*

PSE's second natural gas Action Plan Item is to complete the Tacoma LNG facility. PSE assumes that the Tacoma LNG facility will be completed and in operation prior to the 2019 winter season and may be needed to provide gas to meet core customer peak needs as soon as the 2021 winter season. However, even at this later stage in the project's development, the project has ongoing and potentially significant permitting issues.[63] Given that the plant is not completed or fully permitted, we agree with Staff that the Company's assumption that a not-yet-operational resource will be available comes with some significant risk to the Company's gas supply for core customers. PSE's next IRP must address what the Company will do in the event the LNG plant or pipeline upgrades are significantly delayed or cancelled.

*l. Stakeholder process*

As this commission has noticed, PSE's IRP meetings and presentations have increasingly attracted scrutiny from the public, environmental advocacy groups, and vendors. This has put additional stakeholder engagement pressure on PSE's IRP team. While we are aware of stakeholder complaints around the discussions of major transmission and distribution planning, we believe the Company adeptly managed its stakeholder process overall. In addition to hiring a facilitator to moderate advisory group meetings, midway through this IRP process PSE hired an internal process manager to facilitate the interaction between the Company and the stakeholders. We heard from our Staff and the stakeholders that the additional hire greatly improved the process. We applaud PSE for recognizing an issue and moving to remediate it mid-cycle.

## IV. Conclusion

The Commission acknowledges that Puget Sound Energy's 2017 Electric and Natural Gas Integrated Resource Plan complies with RCW 19.280.030, WAC 480-100-238, and WAC 480-90-238. The Commission expects PSE to follow the recommendations outlined in this letter as it develops future IRPs.

## V. Separate Statement of Commissioner Balasbas on Part III g.

I agree with my colleagues that in future IRPs, PSE should incorporate the cost of risk of future greenhouse gas regulation in addition to known regulations in its Integrated Resource Planning Solution (i.e. lowest reasonable cost portfolio). However, for the reasons outlined below, I

[62] Dockets UE-160918 and UG-160919 Staff Comments on PSE's 2017 Electric and Natural Gas IRP, p. 18.
[63] Puget Sound Clean Air Agency, "Current Projects: Puget Sound Energy - LNG Facility Tacoma." http://www.pscleanair.org/460/Current-Permitting-Projects.

respectfully disagree with my colleague's expectation that PSE use in its lowest reasonable cost portfolio the social cost of carbon as the proxy for future greenhouse gas regulation.

The 2018 legislature considered, but did not take final action on, House Bill No. 2839 and Senate Bill No. 6424. These bills, among other provisions, amended Commission statutes to require use of a "greenhouse gas planning adder" when evaluating integrated resource plans as well as intermediate-term and long-term resource options selected by electrical and gas companies under Commission jurisdiction.[64] The greenhouse gas planning adder can also be referred to as the social cost of carbon. The legislature's mere consideration of this provision indicates there is not clear authorization in current statute for the Commission to require use of the social cost of carbon in IRPs.

The expectation for PSE to use the social cost of carbon in its preferred portfolio is a clear statement that the 2018 legislation was irrelevant. I strongly disagree and would instead defer to the legislature's judgment of the Commission's statutory authority.

When commenting on IRPs, it is appropriate for the Commission to request scenarios using specific assumptions. However, I do not believe the Commission should mandate use of specific assumptions in the ***utility's*** preferred portfolio. My preference would have been to ask PSE to model a separate scenario in its 2019 IRP that uses the social cost of carbon. Then PSE can decide whether that model outcome should be used in its lowest reasonable cost portfolio.

Finally, I disagree with my colleagues mandating the use of the social cost of carbon to represent the "lowest reasonable cost" portfolio. As the Federal Energy Regulatory Commission recently stated in an order, "Without complete information, an analysis using the Social Cost of Carbon calculations would necessarily be based on multiple assumptions, producing misleading results."[65] While IRPs are by necessity assumption driven, I am concerned that requiring use of a speculative tool to choose a preferred portfolio could lead to higher than necessary rates for utility customers.

---

[64] ESHB 2839, Section 3

[65] FERC Docket Nos. CP14-554-002, CP15-16-003, CP15-17-002 Order on Remand Reinstating Certificate and Abandonment Authorization, ¶ 41 (Issued March 14, 2018)