

Attachment A
Utilities and Transportation Commission Comments on
Puget Sound Energy's 2013 Integrated Resource Plan
Dockets UE-120767 & UG-120768

I. Introduction

As an electric and natural gas utility operating in Washington, Puget Sound Energy (PSE or Company) has a fundamental responsibility to manage the risks and opportunities associated with acquiring and delivering electricity and natural gas on behalf of its customers. Technological advances have lowered the cost and increased the availability of natural gas supplies, renewable resources, and distributed resources. At the same time, the environmental impacts of energy production are receiving greater state and federal attention. The planning requirements in WAC 480-100-238 and WAC 480-90-238 are intended to help each utility develop a strategic approach to meet future resource needs against this backdrop of shifting regulatory, technological and market conditions. PSE's 2013 Integrated Resource Plan (IRP or Plan) represents such a strategic approach, and complies with the rules set forth by the Washington Utilities and Transportation Commission (Commission). However, in certain areas PSE's IRP fails, to meet the Commission's expectations of clarity, transparency and thoroughness. The Commission recognizes the significant efforts that PSE performed in the modeling and analyses in this IRP, as well as engaging with Staff and other stakeholders. In the following, we provide specific comments and requests for improvement in the next round of IRPs. The Commission's comments relating to the analysis of the Colstrip generating facilities are stated separately in Attachment B.

II. General Comments

PSE's analysis of resource needs over a 20-year planning horizon is expansive and based on sound modeling approaches. The Commission recognizes PSE's introduction of two new types of analysis into this IRP. A typical IRP assumes the continued operation of existing resources until the end of the resource life. At the direction of the Commission, PSE modeled the costs of continued operation of the Colstrip power plant under different environmental regulatory scenarios. PSE developed a comprehensive modeling approach to integrate the Colstrip analysis with the rest of the Plan. This IRP also included an "operational flexibility" analysis, which evaluated the adequacy of PSE's system to meet hourly and intra-hourly fluctuations of variable renewable resources. This is a promising start and the Commission encourages the company to continue to refine and integrate new types of analysis into the IRP.

Although the overall modeling approach was well developed and executed, certain assumptions and conclusions require further explanation from the Company. For example, PSE’s electric analysis relies on an assumption that “sufficient interruptible natural gas pipeline capacity” will be available for peakers (generating plants intended to serve peak load) with oil back-up, but PSE made no attempt to quantify what qualifies as sufficient. Similarly, the Company’s analysis of the availability of gas-for-power lacks interaction with the operational flexibility analysis and a clear connection to the gas storage resources selected in the Plan. PSE presented the conclusions of its Colstrip analysis were presented on an aggregate level for all four units, while the results differed significantly between Units 1 and 2 and Units 3 and 4. These instances are representative of several logical gaps throughout the IRP, and as a result, the IRP is not as useful a tool as it could be to help the Company guide its decisions on least cost resource selection.

III. Electric Resources

Load Forecasts

Over the 20-year planning horizon of the IRP, absent the acquisition of demand-side resources, PSE expects peak demand to increase by 1.9 percent per year, from 4,837 MW in 2012 to 7,113 MW in 2033.¹ Accelerated acquisition of demand-side resources keeps demand relatively flat in the early years. PSE anticipates that a system-wide peak capacity deficit of 12 MW will occur in 2017 in the Base Scenario, growing to 100 MW in 2020 and 2,194 MW in 2033.²

More specifically, from 2017 on, PSE projects annual load growth of 2.2 percent before accounting for the effects of conservation.³ The load growth projections from 2017 and beyond are mostly driven by the inputs to the econometric model and are themselves projections of the level of economic growth. For instance, job creation in 2017 is expected to be 0.6 percent higher than employment growth from 1997-2011.⁴ Commission also finds little in the way of explanation for how and which underlying inputs change in 2017 to create a higher rate of load growth beyond 2017.

¹ PSE 2013 IRP, page H-20. PSE includes 2012 in its load forecasts because the forecasts were developed in 2012.

² PSE 2013 IRP, page 1-5.

³ PSE 2013 IRP, pages H-19 and H-21, see also bottom of page H-1.

⁴ PSE 2013 IRP, page H-16. The difference between the projected 1.4 percent employment growth and the 0.8 percent employment growth over the last 15 years.

The IRP does not show a need for PSE to acquire additional renewable resources to meet the Renewable Portfolio Standard until 2023, due to PSE's early acquisition of renewable resources and expected banking of Renewable Energy Credits for use in future years. By 2033, the IRP shows a need for 300 MW of renewable energy, probably wind.

Currently, distributed generation (DG) on or interconnected with PSE's distribution system has a cumulative capacity of approximately 39 MW,⁵ and the net metering cap will increase by another 11.2 MW starting January 1, 2014. As mentioned above, PSE's IRP identifies a capacity deficit of 12 MW in 2017, growing to 100 MW by 2020, and yet PSE did not explicitly include potential impacts from distributed generation in its load forecasts. Existing DG capacity, let alone expected DG growth, could significantly affect the timing of resource acquisition in the first half of the planning horizon. Similar to modeling DG, PSE should also include in its load forecasts the capacity available from customers on interruptible schedules.

- PSE should provide greater explanation and support of its load growth assumptions in the next IRP.
- The Commission expects PSE to model distributed generation's growth and contribution to meeting peak and energy demand in the next IRP and prior to its next Request For Proposals (RFP).
- PSE should account for interruptible capacity connected to its system when it develops the load forecasts in the next IRP.

During the IRP development process, the Industrial Customers of Northwest Utilities (ICNU) requested information related to the cost impacts of different planning reserve margins. ICNU has reviewed similar information from other utilities and planned to conduct independent analysis and make specific recommendations regarding appropriate margins. PSE agreed to provide that information, but failed to do so. The Commission believes that the type of public participation offered by ICNU is essential to the development of a robust and effective plan. Limiting such participation by failing to respond to reasonable requests for information is unacceptable.

- PSE should improve the transparency of its planning margin analysis. In the 2015 IRP, the Company should develop a process to allow stakeholders to better understand the assumptions, the analysis, and the results of the company's planning margin.

⁵ Docket UE-131883, Puget Sound Energy Comments filed November 6, 2013.

Supply and Demand-Side Resources

To meet projected loads, PSE modeled the following prospective resources:

- Renewal of transmission contracts that give PSE access to market purchases from Mid-Columbia⁶;
- Combined-cycle combustion turbines (CCCTs);
- Single-cycle combustion turbines (peakers)⁷;
- Southeast Washington wind; and
- Demand-side resources.

The plan describes several other resources that PSE did not model because the assumed resource costs were too high to be practical or their contribution to meeting load was insufficient to displace the need for the resources listed above. These resources include biomass, battery storage, fuel cells, pumped storage hydro, solar, geothermal, tidal and wave power, long-haul wind, and unbundled RECs.

After modeling a wide variety of economic scenarios, PSE selected the following resources for its “selected resource plan”:

Table 1.
Electric Resource Plan, Cumulative Nameplate Capacity of Resource Additions⁸

	2017	2023	2027	2033
Demand-Side Resources (MW)	327	800	887	1007
Wind (MW)	0	300	500	600
Peakers (CT in MW)	221	442	1,327	2,212
Transmission Renewals (MW)	1,141	1,407	1,407	1,657
Gas Storage (MDth/day Gas)	100	100	100	150

⁶ In meeting its peak load needs, PSE includes transmission capacity to Mid-Columbia generation resources in its supply-side resources even though the transmission capacity does not have a specific generator committed to supply power.

⁷ Although PSE evaluated the capital and operating costs of multiple peaker sizes, as well as peakers on both the west side and east side of the Cascades, PSE only modeled westside 221 MW Frame peakers with oil backup in the scenarios.

⁸ PSE 2013 Integrated Resource Plan, page 1-8.

The selected resource plan calls for the acquisition of nine peakers in 10 years starting in 2023. This heavy reliance on peakers is grounded in the assumption that sufficient interruptible gas capacity will be available to operate the peakers. If sufficient capacity is not available, CCCTs become more cost-effective. However, without any analysis to determine what capacity would be considered “sufficient,” PSE’s conclusion that peakers are the least cost natural gas resource is questionable. This conclusion is even more concerning given that PSE acknowledged during the IRP presentation that none of the peakers are needed to balance variable renewable resources. We also are concerned, as pointed out by other stakeholders, that the Company’s supply-side analysis overall relies too heavily on one particular type of technology, namely single-cycle gas peakers. While these units potentially offer the benefits of quick ramping, lower capital costs, and reliance on interruptible pipeline capacity, we would note that they may be more expensive to operate in a stand-by mode and may be less efficient in meeting peak demand when running at less than full capacity. We therefore expect the Company to provide more detailed analysis on a broader range of alternatives to peakers in the next IRP.

PSE did not provide sufficient analysis to show that its peak load will become more extreme over time. During its presentation of the IRP, PSE acknowledged that none of the peakers were needed to balance variable renewable resources. The Commission questions whether peakers are needed to meet increasing peak load or to meet slowly-increasing base load. If the latter, a steady build-out of peakers may not be the least-cost option to meet PSE’s system needs. The Commission identified its concern regarding peaker assumptions in its acknowledgment letter for PSE’s 2011 IRP,⁹ and PSE has not sufficiently improved its modeling approach. The Commission also is concerned about the assumption that “a certain amount of gas storage is available to the CCCTs plants modeled.”¹⁰ The company should attempt to quantify to some extent this “certain amount” of gas storage.

- In every IRP, PSE should attempt to quantify and validate assumptions regarding each resource’s operational and performance characteristics. For example, PSE should quantify the amount of interruptible gas capacity used by peakers in the model, and provide the details for assuming that this capacity will be available when needed.
- Explain how changes in the load ratio (peak to base) affect the relative economics of different types of generation resources.

⁹ Dockets UE-100961 and UG-100960, IRP Acknowledgment Letter Attachment, page 7.

¹⁰ Dockets UE-120767 and UG-120768, PSE 2013 Integrated Resource Plan, page 5-24.

- Provide more detailed justification for any assumptions or inputs into the load forecasting model.

In its 2011 IRP Acknowledgment letter, the Commission requested that the Company include “a discussion of the technologies of electric storage, their cost-effectiveness, commercial availability, and proper classification compared to other forms of generation.”¹¹ Although PSE added discussion of energy storage technologies to the 2013 IRP, we find the level of evaluation to be insufficient. The primary source of cost and performance data was from a study conducted in 2010. Energy storage is rapidly developing, and the Commission questions whether the use of 2010 data for the 2013 IRP gave energy storage a fair opportunity to compete with other resource options. PSE received multiple storage bids in a recent RFP solicitation process, which PSE could have used to update cost and operational assumptions for those storage technologies. Further, PSE does not explain its method for quantifying energy storage costs and benefits.

- In its next IRP, PSE should update its energy storage analysis with recent market data, clarify its assumptions regarding expected operational conditions for storage systems, and include ancillary services in the energy storage analysis. The Commission encourages PSE to rely on a wide variety of national and state data, especially those available on the California storage market as providers respond to the recent decision by the California PUC in an Order implementing AB 2514. The first solicitation of bids is scheduled for December 2014, and new market data should be generated through this RFP.
- PSE should specify the operating and performance characteristics it prioritizes for energy storage technologies prior to issuing its next RFP.

The Commission considers the conservation potential assessment in Appendix N to be adequate for the purposes of the IRP, and the Commission addressed the results of the assessment through the biennial conservation target setting process. However, we note that PSE can improve the usefulness of its conservation potential assessment by modeling demand response as a resource separate from energy efficiency. The assessment, conducted by The Cadmus Group, identifies the cost-effective demand response potential available in PSE’s service territory, in addition to traditional energy efficiency measures. Demand response programs typically have very different peak reduction characteristics than energy efficiency measures, but PSE combined these resources into the same cost bundles for modeling least-cost resource portfolios. The effect is that the IRP does not take into account the flexible peak reduction benefits provided by demand response. The

¹¹ Dockets UE-100961 and UG-100960, IRP Acknowledgment Letter Attachment, page 9.

Commission is concerned that the IRP fails to provide useful guidance on how much demand response the Company should pursue, and on what timeline.

- In the next IRP, PSE should model demand response as a resource separate from energy efficiency in the portfolio screening model.

CO₂ Costs

Building from the Company's 2011 IRP, PSE included four CO₂ price or cost forecasts in the 2013 IRP. PSE assigned relative probabilities to the forecasts to conduct stochastic analysis and develop a weighted average cost of CO₂. The forecasts were used in a variety of scenarios to determine the impact of various CO₂ prices on the optimal resource portfolio. However, PSE assumed in its Base Scenario that there would be a zero cost of CO₂. The Commission finds this inappropriate for a number of reasons. Although PSE is not currently paying for CO₂ emissions, there is growing evidence that society and PSE ratepayers are bearing the costs of those emissions, and that those costs are not zero. PSE already acknowledges a cost of carbon in its rate design. Since PSE's 2009 general rate case, PSE has included a CO₂ emissions cost forecast drawn from the IRPs in its peak credit allocation methodology. The Company provided the following justification for this change in its 2009 testimony:

While there continues to be uncertainty surrounding the ultimate way in which greenhouse gases will be regulated, since the Company's last general rate case, there has been a greater recognition that some form of regulation will apply in the future. . . . With the heightened state of interest in controlling greenhouse gas emissions at the state and federal levels, and consistent with the recognition of future emissions costs in its resource planning, the Company believes the time is right to introduce these costs into the peak credit methodology.¹²

PSE has maintained this approach for including emissions in its peak credit methodology through subsequent rate cases. The Commission finds it inconsistent for PSE to include a cost of CO₂ in its cost of service but omit a similar "recognition of future emissions costs" in the Base Scenario of its IRP. PSE's own judgment of risk resulted in a weighted average cost of CO₂ that is quite similar to the forecast embedded in the Company's peak credit methodology.

- PSE's next IRP must include in the Base Scenario a non-zero cost of CO₂ emissions. This issue is discussed more fully in Attachment B.

¹² Docket UE-090704, Exhibit No. JAP-1T, 6:10-7:12.

Transmission and Distribution

New resources typically require additional transmission and distribution facilities to connect to a utility's system. However, PSE only modeled new resources located west of the Cascades, and assumed that the output of these resources could be delivered to PSE's load (and to market) without new transmission or distribution facilities. In contrast to the 2011 IRP, this IRP did not include any evaluation of new potential transmission projects even though the Plan calls for nearly a dozen new peakers. Chapter 7 of the IRP describes PSE's current distribution infrastructure plan. However, this plan is developed outside of the IRP by a different group within the Company, and there is very little connection between it and the resources modeled in the rest of the IRP. Should the Company pursue resources that are not adjacent to its service territory, the Commission fully expects PSE to consider the costs of transmission for those resources.

- In the next IRP, PSE should model the transmission constraints present in its system and the impact those constraints have on resource selection.
- The Company should explicitly describe the relationship between the infrastructure and IRP planning processes.

Process

The process for developing the 2013 IRP saw a marked increase in public participation from recent IRP processes. This is in no small part due to the increased salience of issues related to PSE's coal resources, which are the subject of litigation by some organizations participating in the IRP process. After a few Advisory Group meetings, Commission Staff (Staff) encouraged PSE to hire a facilitator to help keep the meetings respectful, focused, and productive. PSE did so, and this significantly improved the tone of the meetings, and resulted in more structured meetings and more transparent communication. PSE has committed to working with an outside facilitator to restructure and facilitate its 2015 IRP stakeholder engagement process.

Despite the improvement, Advisory Group members expressed continued frustration with the way PSE responded to questions or requests for data. Incomplete access to confidential information hindered Advisory Group participation and trust. Certain data were not provided to the full Advisory Group or presented in the filed IRP due to concerns about confidentiality. Yet, PSE did not take advantage of standard Commission practice for the handling confidential information. These omissions inhibited Staff review of the IRP, which the Commission finds unacceptable.

- The Commission encourages PSE to continue using an outside facilitator to manage the Advisory Group meetings. Additionally, the Commission expects the Company to provide written responses to all Advisory Group questions submitted to the Company in writing, and to provide minutes for each Advisory Group meeting. The Commission requests the Company include these practices in its workplan for the next IRP.
- PSE should work with stakeholders to develop a reasonable set of input assumptions and reasonable set of results in a format that will be useful for stakeholders.
- If necessary, PSE should make full use of existing provisions to manage confidential information.

IV. Natural Gas Resources

PSE expects that annual natural gas load will increase at an average annual rate of 1.4 percent per year, growing from approximately 1.1 billion therms in 2012 to almost 1.5 billion therms in 2033. PSE also expects peak loads to increase at an average rate of 1.8 percent per year, from 8.9 million therms in 2012 to 13.5 million therms in 2033. Many of the same economic and regional inputs and assumptions are used for developing its natural gas load forecasts as for the electric load forecasts.

The Commission considers PSE's approach to natural gas modeling and the reasoning applied to model results to be sound. The Company evaluated an alternative extreme weather peak design and concluded that further analysis of that design is required. The Commission appreciates PSE's commitment to using appropriate methodology as well as its caution in considering a methodological change. The Commission also recognizes PSE's efforts to evaluate the impact of the gas sales and gas-for-power portfolios on its resource mix. We encourage PSE to continue to refine both of these analyses in the next IRP.

To meet projected loads, PSE modeled the following resource options:

- Expansion of the Westcoast Pipeline and associated expansion of Northwest Pipeline (NWP);
- The proposed Kingsvale-Oliver Reinforcement Project (KORP) and associated expansion of NWP;
- Two options for the prospective Palomar/Blue Bridge pipeline, or what is now termed the Northwest Market Area Expansion (N-MAX) project;
- The proposed PSE LNG peak-shaving facility;
- Upgrades to the existing Swarr propane-air injection facility;

- Expansion of Northwest Natural’s Mist storage facility; and
- Demand-side resources.

After modeling a wide variety of economic scenarios, PSE selected the following resources for its Plan:

**Table 2.
Gas Resource Plan, Cumulative Additions in MDth/Day of Capacity¹³**

	2018-2019	2022-2023	2027-2028	2032-2033
Demand-Side Resources	15	28	33	37
PSE LNG	50	50	50	50
Swarr Upgrade	30	30	30	30
Mist Storage Expansion	50	50	50	50
Westcoast/NWP Expansion	0	54	150	150
KORP/NWP Expansion	0	0	0	78

PSE has a policy of acquiring natural gas resources roughly four years ahead of need, due to the long lead time for constructing new supply resources and the need to acquire large blocks of pipeline capacity at a given time. The Commission acknowledges the reasonableness of this approach, but is concerned that PSE’s modeling does not fully reflect this lead-time constraint. PSE’s model selects 17 MDth per day of Mist Storage in the 2018-2019 heating season, which increases to 50 MDth per day by 2022-2023. However, PSE’s Plan calls for acquisition of the full 50 MDth per day by 2018-2019 to secure the capacity needed in later years. Early acquisition of 50 MDth per day of Mist Storage, combined with demand-side resources, would appear to meet PSE’s resource need until the 2020-2021 heating season. The company should analyze the relative additional necessity of additional Mist storage in conjunction with the LNG and Swarr resources.

- In the next IRP, PSE should conduct a second run of its model once the appropriate blocks of pipeline capacity are selected, to assess whether early acquisition of pipeline blocks impacts the timing of the selection of other resources.

¹³ PSE 2013 Integrated Resource Plan, page 1-14.

V. **Conclusion**

The Commission acknowledges that Puget Sound Energy's 2013 Electric and Natural Gas Integrated Resource Plan complies with WAC 480-100-238 and WAC 480-90-238. However, in several areas, PSE's Electric IRP fails to meet the Commission's expectations of clarity, transparency and thoroughness. The Commission expects PSE to follow the recommendations outlined in this letter as it develops its next IRP.