



STATE OF WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

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May 9, 2016

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

**Re: Puget Sound Energy's 2015 Electric and Natural Gas Integrated Resource Plan
UG-141169 & Docket UE-141170**

Dear Mr. Johnson:

The Washington Utilities and Transportation Commission (Commission) has carefully reviewed the 2015 Electric Integrated Resource Plan (IRP) filed by Puget Sound Energy (PSE) on November 25, 2015, and finds that it meets the requirements of Revised Code of Washington 19.280.030 and Washington Administrative Code (WAC) 480-100-238 and 480-90-238.

Please be advised that this finding does not signal pre-approval for ratemaking for any course of action identified in the IRP. At the time of the Commission's review of a future PSE request to include costs of resources into rates, the Commission will give due weight to the information, analyses and strategies contained in the most recent IRP along with other relevant evidence when determining the prudence of the company's actions.

Because an IRP cannot pinpoint precisely the future actions that will minimize a utility's cost and risks, we expect that the company will update regularly the assumptions that underlie the IRP, pursue additional information, and adjust its operational strategies accordingly.

Attached are specific comments from the Commission regarding the 2015 Plan. Commission Staff will provide additional detailed comments as PSE develops its next IRP. PSE should file its next IRP work plan on or before July 15, 2016, and its next IRP on or before July 15, 2017.

Sincerely,



STEVEN V. KING
Executive Director and Secretary

Attachment - UTC Comments on Puget Sound Energy's 2015 IRP

Attachment
Utilities and Transportation Commission Comments on
Puget Sound Energy's 2015 Integrated Resource Plan
Dockets UG-141169 and UE-141170

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 ensure each utility develops a strategic approach to meet future resource needs against this backdrop of shifting regulatory, technological and market conditions. PSE's 2015 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 the 2015 IRP, as well as engaging with Staff and other stakeholders. In the following sections, we provide specific comments and requests for improvement in certain areas in the next IRP.

II. General Comments

PSE was granted two extensions to file its 2015 IRP while the Company incorporated foundational changes to its planning process, including a new load forecasting model and the development of a new planning standard. This new standard would incorporate a value of reliability, a market risk assessment, and a new means of determining the capacity value of resources. Using this new approach, PSE concludes that the cost of an additional power plant is justified to reduce both the probability and magnitude of potential curtailment events.

Part III of this attachment discusses the IRP's overall conclusions regarding the timing and specific type of future electric resource additions, then focuses on the proposed new planning standard. Part III continues with a discussion of assumptions regarding demand-side resources, supply-side resources, and reserve requirements. Part IV discusses modeling improvements requested by the Commission, and part V addresses procedural issues. Finally, part VI examines the natural gas plan.

III. Electric Resources

Load Forecasts

PSE projects that annual electric system demand will increase from 2,629 average megawatts (aMW) in 2016 to 3,598 aMW by 2035, an average annual growth rate of 1.7 percent over the 20-year planning period. Peak demand is projected to grow at a rate of 1.6 percent per year over the same period, from 4,929 MW in 2016 to 6,649 MW in 2035.

While the growth rates have been revised downward from the 2013 IRP, PSE emphasizes that growth is uneven in its service territory. A significant portion of the IRP is devoted to documenting the rapid growth in its King County service territory.

In the 2015 IRP, the Company uses a new, econometric load forecasting model.¹ In previous IRPs, PSE used a simplified use per customer model, in which the Company estimated how much gas or electricity the average customer used and multiplied that number by the expected number of customers each year. The Commission is more comfortable with the ability of an econometric model to respond to the increasingly granular nature of load drivers. As the results of the new model do not widely differ from the load forecast in the 2013 IRP derived from the simplified model, going forward PSE should continue to use an econometric approach to demand forecasting.

Resource Plan

PSE's resource plan describes the portfolio it sees as most likely to meet future needs at this point in time. It continues to rely heavily on energy efficiency and market purchases throughout the planning period. The Company plans to continue to rely on its 1,666 MW of available transmission to the Mid-Columbia market hub to make market purchases for energy and capacity, while its energy efficiency acquisitions for the 20-year planning period total 906 MW.

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

¹ Econometric models (also called regression models) are statistical models that analyze the relationship among a wide range of inputs (such as weather, economic conditions, employment rates, etc.) and how they interact to affect a given output (such as electricity or gas consumption).

Table 1
Electric Resource Plan, Cumulative Nameplate Capacity of Resource Additions²

	2021	2023	2027	2033
Conservation (MW)	411	669	770	906
Demand Response (MW)	121	130	138	148
Wind (MW)	-	206	337	337
Peakers (CT in MW)	277	403	609	609
Combined Cycle Gas (MW)	-	577	577	805

PSE's Proposed New Planning Standard

In previous IRPs, PSE has planned its system to meet a 5 percent loss-of-load probability (LOLP) metric.³ This means that the Company plans its system to have sufficient resources to ensure that across the broad range (hundreds) of system conditions under which the Company models, only 5 percent of those would result in an outage caused by insufficient supply.

In the 2015 IRP, PSE proposes to use a new planning standard that consists of three components:

- a cost-benefit approach to establishing the planning margin that would set it at the point where the cost of additional resources matches the benefit of the increased reliability that they provide,
- a new method of determining the capacity value of existing and prospective resource alternatives, and
- a risk metric for market purchases.

Together, these three changes swing the Company's capacity position in 2021 from a projected surplus of 150 MW to a projected deficit of 234 MW, thereby creating the projected need for a gas plant in 2021.⁴ It is important to note that this projected resource need is *solely* the result of the changes to the Company's planning standard – it is not driven by higher load forecasts, accelerated resource retirements, or any other factor. PSE

² PSE 2015 Integrated Resource Plan, page 1-17, figure 1-7.

³ This is the same metric used by the Northwest Power and Conservation Council in its annual regional resource adequacy evaluation.

⁴ PSE 2015 IRP, page 2-3 (Figure 2-1) shows that under the previous planning standard, PSE would be 150 MW long on capacity in 2021. *Id.*, page 1-14 (Figure 1-4) shows the Company needing 275 MW in 2021.

states it is looking for feedback from the Commission regarding this new planning standard, as it dramatically impacts the Company's near term capacity need.⁵

The section below provides the Commission's analysis of the three components of PSE's proposed planning standard.

Cost-Benefit Approach to Reliability

The central piece of PSE's proposed new planning standard is a cost-benefit approach to establishing reserve margins, which proposes to add generation to improve reliability until the marginal cost of the new resources equals the marginal benefit of the additional reliability they provide.

While this analysis is interesting from the perspective of economic theory, it appears to be a solution in search of a problem. The Company does not identify any deficiencies in the current 5 percent LOLP standard or identify the last curtailment event driven by insufficient generation on PSE's system, stating only that it was more than 20 years ago.⁶ PSE criticizes the 5 percent LOLP standard for being arbitrary, and while that may be true, it has nevertheless yielded reliable service for PSE's customers. Moreover, the LOLP approach is reasonable, has become a standard in the electric power industry, and has been used for many years by the Northwest Power and Conservation Council (NPCC).

The impact of the cost-benefit approach to reliability is immediate and substantial – 277 MW of additional generation by 2021, at a cost of hundreds of millions of dollars. The Company carries a substantial burden to justify a change in the historical planning standard, especially when the change results in significant ratepayer impacts. As the Company has not met this burden, we reject the planning standard proposed by PSE.

The Commission also has significant concerns regarding the means by which PSE calculated the value of reliability to its customers. Placing a value on reliability is a highly subjective exercise, and PSE's choice of data for this exercise further exacerbated the challenge. PSE calculated its values using a tool provided by the U.S. Department of Energy, but the underlying values in that tool are based on data from 2007 that was compiled nationally and then averaged by state. A statewide average would hardly be representative of PSE's service territory, even if the averaged data used was not nearly a decade old.

⁵ PSE 2015 IRP, page 2-2.

⁶ In contrast, the Company experiences many outages each year due to distribution system impacts.

- The Commission rejects PSE's cost-benefit of reliability analysis, primarily because PSE did not identify a deficiency in its current planning standard.

Resource capacity values

PSE has adopted a new means of determining, for planning purposes, the capacity value of existing and prospective resources. This new method, called the Incremental Capacity Equivalent (ICE), rates a resource by the equivalent nameplate capacity of a natural-gas fired peaking plant that the system would need to add to achieve the same value for expected unserved energy (EUE).⁷

For example, future Washington wind resources received an ICE value of 8 percent, meaning that it would take approximately 12.5 MW of new wind to provide the same amount of capacity as 1 MW of natural gas peaking capacity.

PSE states that the ICE method is similar to the Effective Load Carrying Capability (ELCC) that has been used or adapted by other utilities in recent years, including Pacific Power. However, it is unclear to the Commission how the ICE method approximates the ELCC, as PSE's results with ICE are directionally different from those obtained by Pacific Power's adaptation of the ELCC. Pacific Power's approximation of the ELCC significantly increased the capacity value of variable renewable resources and reduced the Company's overall capacity need. PSE's use of ICE left the capacity value of new wind resources unchanged, but reduced the capacity value of existing wind resources by about 25 percent,⁸ and increased the Company's overall capacity need. While the Commission supports the use of an approximation of the ELCC as a way to set a capacity value for renewable resources, PSE's IRP does not justify adequately the use of the ICE method.

- In the next IRP cycle, PSE should consider other methods of approximating ELCC, including methods used by other planners in the region, and discuss this topic with the advisory group.⁹

⁷ *Id.*, pages 6-12 and 6-13.

⁸ *Id.*, page 6-13, figure 6-6.

⁹ *See, i.e.*, Madaeni, S. H., et al, Comparison of Capacity Value Methods for Photovoltaics in the Western United States, Nat'l Renewable Energy Lab, available at <http://www.nrel.gov/docs/fy12osti/54704.pdf> (2012); Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning, N. Am. Elec. Reliability Corp., available at <http://www.nerc.com/files/ivgtf1-2.pdf> (March 2011).

Market risk

In the market risk assessment, PSE endeavored to determine how potential regional capacity shortfalls could affect the Company. The process generally followed these steps:

- Identify the amount of regional capacity shortfall during the region's winter peak in a particular scenario of the regional resource adequacy model;
- Identify how much capacity regional utilities are relying on the market to provide in their individual IRPs;
- Allocate the energy shortfall among the utilities that would be purchasing winter peak capacity.

This is the first time in recent memory that a utility presents the Commission with a quantification of the risk of relying on the market for a portion of its capacity need. It is clear that PSE devoted substantial resources to develop this analysis and the Commission commends the Company for this effort. This market risk model appears fundamentally sound and represents a reasonable means of modeling a difficult challenge. The Commission encourages the Company to continue to model market risk in future IRPs.

- As this is a relatively novel effort, PSE should discuss with the advisory group whether other market risk models are available for use in the 2017 IRP.
- If PSE continues to use the model it developed in the 2015 IRP, it should continue to refine the model. The Company should review with the advisory group every modification to the assumptions used in the Pacific Northwest Power Supply Adequacy Assessment.¹⁰

Summary

The proposed planning standard includes multiple elements that have an end-result of increasing PSE's resource need in the near term. The cost-benefit of the reliability component creates a need for additional resources, while the market risk and ICE components simultaneously discount the capacity value of many of the resources used to meet that need. This type of fundamental shift requires significant justification and PSE has failed to provide that justification.

¹⁰ For instance, PSE could capture more accurately each utility's projected market need, model more accurately when gas plants without firm pipeline capacity can operate, and include all plants acknowledged to operate by the Pacific Northwest Power Supply Adequacy Assessment.

Utilities use a wide variety of metrics including LOLP, EUE, Loss of Load Hours, and planning margins, to evaluate resource adequacy. In the 2015 IRP, PSE inappropriately focused on a “shift” from using one metric (LOLP) to another (EUE). Instead of choosing one metric to focus on and devaluing the others, PSE should present multiple metrics in the 2017 IRP and focus on minimizing total risk to customers by evaluating all the data available.

Further, with the exception of the market risk assessment, PSE instituted all of these changes very late in the IRP cycle. Every stakeholder comment the Commission received on the new planning standard opposed the change. Stakeholder opposition and the late disclosure of this change is particularly concerning considering the Commission’s direction two years ago that PSE “improve the transparency of its planning margin analysis” and “develop a process to allow stakeholders to better understand the assumptions, the analysis, and the results of the Company’s planning margin.”¹¹

- The 2015 IRP does not demonstrate that the cost-benefit approach or the ICE method are appropriate ways to set PSE’s planning margin. PSE should not rely on these methods as justification for procuring a new resource at this time.
- PSE should present various resource adequacy metrics in each IRP.

Demand-side Resources

The 2015 IRP selects 906 MW of electric energy efficiency by 2035.¹² The plan calls for the Company to acquire nearly half of that, 411 MW, by 2021. The plan also selects 69 MDth/day in natural gas efficiency programs by 2035, including 12 MDth/day by 2018. The Commission has already reviewed and approved PSE’s 10-year conservation potential and biennial conservation targets for the 2016-2017 biennium in dockets UE-152058 (electric) and UE-152075 (natural gas).

Under its 2013 Planning Standard, PSE identified a need for 131 MW of Demand Response by 2021,¹³ but notes that the Company does not currently have programs in place to achieve that resource. The action plan commits PSE to issue a request for proposals (RFP) to acquire Demand Response.¹⁴ Given the IRP’s aggressive selection of Demand Response resources (118 MW by 2020) and PSE’s relative inexperience in acquiring Demand Response resources, the Commission supports PSE’s decision to move quickly.

¹¹ UE-120767, Attachment A to PSE 2013 IRP Acknowledgment Letter, at 3 (Feb. 6, 2014).

¹² PSE 2015 IRP, page 2-7.

¹³ PSE 2015 IRP, Page 6-38.

¹⁴ PSE 2015 IRP, Page 1-10.

- PSE should continue to model demand response as a resource separate from energy efficiency in the portfolio screening model.

Supply-side Resources

PSE makes several significant changes to the way gas-fired generation plants are treated in the 2015 IRP.

In previous IRPs, a peaking plant would require either firm pipeline capacity to run on natural gas, or interruptible pipeline capacity supplemented by oil stored in tanks for use when pipeline capacity is not available. In the 2015 IRP, peaking plants with oil tanks also require firm pipeline capacity 12 hours a day, increasing a peaking plant's cost relative to other resources.¹⁵ We believe the IRP's claims need more support and analysis.

First, the IRP states PSE will face constraints on its "ability to construct a backup fuel tank and obtain adequate air permits."¹⁶ Yet PSE also acknowledges there "are no specific rules/regulations (that PSE is aware of) prohibiting the construction of oil backup facilities."¹⁷ Second, PSE expresses concern that emission limits may become increasingly tighter, resulting in an inability to run peaking plants on oil for extended periods.¹⁸

- In the 2017 IRP, PSE should model peaking plants operating on a full oil backup, or provide documentation to support an assumption that environmental or permitting restrictions would prohibit such operation.

PSE's 2015 IRP also changes the way that major maintenance at peaking plants is modeled. In earlier IRPs, major maintenance was treated as a fixed cost, while in the 2015 IRP major maintenance is included in the plant's variable costs.¹⁹ This change was not described in the IRP. As a result of this increase in variable costs, the 2015 IRP's base case includes no output (zero MWh) from peaking plants over the 20-year planning horizon. The Commission does not believe this result is reasonable.

¹⁵ PSE 2015 IRP, page 2-15. PSE uses the shorthand "50% Firm Pipeline" to mean 12 hours a day.

¹⁶ PSE 2015 IRP, page 2-15.

¹⁷ PSE's response to WUTC Staff Informal Data Request No. 5, at 1.

¹⁸ PSE 2015 IRP, page 2-15; PSE's response to WUTC Staff Informal Data Request No. 5, at 1. Additionally, the IRP notes that "there is no dispatch" of the peaking plants across all deterministic scenarios, except for Low, where there is a very small dispatch. PSE 2015 IRP, page 6-43.

¹⁹ PSE's response to WUTC Staff Informal Data Request No. 8, at 1-2. This increased a peaking plant's variable operations and maintenance from \$0.44/MWh to \$2.69/MWh. *Id* at 2.

- In the next IRP cycle, PSE must revisit this assumption with its technical advisory group. In the 2017 IRP, PSE should provide a narrative discussion of the treatment of major maintenance costs at thermal plants.
- The 2015 IRP's failure to disclose a change with such a significant impact on the dispatch of its thermal fleet raises questions about the transparency and clarity of the presentation of the IRP.²⁰ In every IRP, PSE must provide a narrative discussion of any changes that result in a significant impact on the dispatch of its thermal fleet.

Finally, PSE analyzes the tradeoffs associated with placing future gas plants in its service territory or in eastern Washington. The analysis concludes that while eastern Washington plants would give the Company access to lower-cost fuel, they would also come with higher transmission costs to move the power across BPA's transmission system. The Company states that this tradeoff was essentially a wash, and that it decided to locate the plants in its service territory to avoid the risks of future, potentially disadvantageous changes in BPA's transmission policy.²¹

A generating plant may be physically located in one area, and virtually placed in another Balancing Area Authority (BAA) using transmission service referred to as dynamic transfer. Under this arrangement, the BAA that virtually receives the generating plant's output is responsible for responding to variations in the plant's output. PSE has dynamic transfer arrangements for several of its generation plants. Unfortunately, the 2015 IRP does not consider the use of dynamic transfer in the placement of future gas plants, or in its consideration of wind resources in eastern Montana.

- In the 2017 IRP, PSE should quantify the costs and benefits of siting gas plants in eastern or western Washington. This analysis should include the use of dynamic transfer into PSE's BAA, and a discussion of the potential risks associated with BPA transmission policies.
- In the 2017 IRP, PSE should again revisit its assumptions regarding eastern Montana wind with the advisory group. Additionally, PSE should model Montana wind's use of transmission made available by the retirement of some units at Colstrip, and consider a sensitivity where Montana wind qualifies for the Washington RPS using a dynamic transfer or other technology.

²⁰ In addition, Public Counsel noted that statements from PSE regarding its level of apprehension about the misinterpretation of the Colstrip analysis was concerning, as PSE should not be limiting the useful, consistent and transparent information it provides stakeholders through the IRP process. The Commission agrees that PSE has an obligation to provide useful and transparent information to the advisory group at every stage of the IRP process.

²¹ PSE 2015 IRP, page 6-61.

Renewable Resources

Though the IRP analyzes various resource options for complying with the Renewable Portfolio Standard (RPS), it does not analyze the potential for complying with future RPS obligations by purchasing unbundled renewable energy credits (RECs).²² Pacific Power, in its last two IRPs, has determined that unbundled REC purchases are a lower-cost means of RPS compliance by a significant margin.

- In its next IRP, PSE should compare the marginal cost of generating a REC from a company-built resource with the costs of purchasing an unbundled REC on the open market.

In comments, Renewable Northwest (RN) and Sierra Club emphasize the importance of ensuring that PSE keeps its renewable resource assumptions up to date because the costs of renewable technologies can fall significantly during a planning cycle. RN, Northwest Energy Coalition, and Sierra Club cite specifically lower prices for utility-scale wind and solar than found in the IRP.

- At the start of the next IRP cycle, PSE should solicit feedback from the advisory group regarding the timing of cost and performance assumptions for renewable resources and energy storage. When presenting these cost and performance assumptions to the advisory group, PSE should clearly identify any “learning curves” used to discount future costs or improve performance of those technologies.

Similarly, the 2015 IRP does not have a sensitivity analysis to consider the impact of renewed federal production tax credits for wind energy. As Congress renewed such credits in December 2015, it may be cost effective for PSE to build the wind resource scheduled for service in 2023 at an earlier date to take advantage of the tax credit.

Reserve requirements

The Northwest Power Plan recommends IRPs include an estimate of the utility’s operating reserve requirement, including which plants should be assigned in power system models to provide these reserves.²³

²² An unbundled REC represents the environmental attributes of renewable energy generation; it is traded independently of the underlying electricity generation.

²³ 7th Northwest Power Plan, page 4-7 (action item REG-4).

- The Commission requests that PSE work with regional stakeholders, including the Northwest Power and Conservation Council Staff, to publish information about PSE's reserve requirements needs in the next IRP.

IV. Modeling Improvements

Thermal plant capital investments

In contrast with the planning of Avista and Pacific Power, PSE's IRP modeling historically has not incorporated the cost of future capital investments in thermal plants. For that reason, consideration of Colstrip retirement in the 2013 IRP was considered a one-off analysis. Electric utilities must consider the realistic possibility that the retirement of thermal plants facing costly retrofits may be the most cost-effective way to serve customers. PSE's IRP models do not account for this possibility, yet PSE owns six combined-cycle gas plants and four peaking plants in addition to Colstrip.²⁴

- PSE must develop a model that economically optimizes the timing of thermal plant retirements, capital investments, and replacement power for use in all future IRPs.

Distribution and transmission system evaluation

PSE's IRP modeling historically has not included distribution system evaluations. PSE's IRP states that "the planning process for addressing local distribution and transmission needs . . . is appropriately separate from the IRP's high-level generic resource and system-wide viewpoint."²⁵ Contradicting this statement, the IRP includes an estimation of the maximum potential of distributed solar generation in PSE's service territory, and the impact of that build-out on its distribution system.²⁶ The statement inappropriately forecloses on the consideration of distribution and transmission system evaluation in the IRP.

WAC 480-100-238(3)(d)-(e) requires the IRP to include "[a]n assessment of transmission system capability and reliability, to the extent such information can be provided consistent with applicable laws," and "[a] comparative evaluation of energy supply resources (including transmission and distribution) and improvements in conservation." PSE did not fully respond to the Commission's direction in its 2013 IRP Acknowledgement Letter to "model the transmission constraints present in its system and

²⁴ PSE 2015 IRP, pages D-5 and D-6.

²⁵ PSE 2015 IRP, page 1-9.

²⁶ PSE 2015 IRP, page 6-81 and Appendix M. This study on distributed solar was done by the Cadmus Group.

the impact those constraints have on resource selection,” and “explicitly describe the relationship between the [distribution and transmission] infrastructure and IRP planning processes.”²⁷ The Commission is concerned that the IRP’s statement regarding distribution and transmission system evaluation contradicts WAC 480-100-238.

- The Commission applauds PSE’s inclusion of an estimation of the maximum potential of distributed solar generation in PSE’s service territory, and the impact of that build-out on its distribution system. In future IRPs, PSE should continue to evaluate the impact of distributed generation on the Company’s generation, transmission, and distribution needs.

Energy Storage and Flexibility

In its 2013 IRP acknowledgment letter, the Commission found that PSE’s evaluation of energy storage technologies was insufficient and inappropriately relied on outdated cost and performance data. In response to the Commission’s 2013 IRP acknowledgment letter directing the Company to improve its modeling of energy storage, PSE began its 2015 IRP with the intention of enhancing its intra-hour flexibility analysis. Despite multiple time extensions, PSE was unable to improve this analysis, and instead filed as Appendix H the same flexibility study it used in its 2013 IRP. In the 2017 IRP cycle, PSE commits to develop further its intra-hour flexibility analysis, including the benefit provided by different types of resources, including battery storage, reciprocating engines and hydro.²⁸

- In the 2017 IRP, PSE should value ancillary services and model the sub-hourly dispatch of its generating resources to the fullest extent possible.
- PSE should specify the operating and performance characteristics it prioritizes for energy storage technologies prior to issuing its next RFP.
- At the start of the next IRP cycle, PSE should solicit feedback from the advisory group regarding the timing of cost and performance assumptions for renewable resources and energy storage. When presenting these cost and performance assumptions to the advisory group, PSE should clearly identify any “learning curves” used to discount future costs or improve performance of those technologies.

²⁷ UE-120767, Attachment A to PSE 2013 IRP Acknowledgment Letter, at 5 (Feb. 6, 2014).

²⁸ PSE 2015 IRP, page 1-11.

V. Process and Public Involvement

The process for developing the 2015 IRP again saw a high level of public participation. This is in no small part due to the salience of issues related to PSE's coal resources, and its Energize Eastside project.

- The Commission encourages PSE to continue using an outside facilitator to manage the Advisory Group meetings.
- Additionally, the Commission continues to expect 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.

The Commission received more than 6,700 individual written comments in response to PSE's IRP. The vast majority of them oppose PSE's continued use of Colstrip. For example, King County Executive Dow Constantine, joined by the Mayors of Mercer Island, Issaquah, Snoqualmie, Redmond, and Tukwila, and Climate Solutions requested greater specificity regarding plans for closure of the Colstrip facility, and a commitment from PSE to replace the facility's power with renewable resources. Climate Solutions and Sierra Club recommend the Commission use PSE's upcoming rate case to address the financial risk to ratepayers, retirement dates, and replacement power.

On March 4, 2015, the Commission held an all-day meeting to hear comments on PSE's IRP. The Commission heard from scores of individuals, including many environmental advocates from Washington and Montana, elected officials from the cities of Olympia, Kirkland, Woodinville, and Bellingham, and citizens concerned about the Energize Eastside project.

The Commission recently addressed the issues raised regarding the Colstrip plant in a different docket. On March 9, 2016, PSE, Commission Regulatory Staff, Public Counsel, Industrial Customers of Northwest Utilities, Northwest Industrial Gas Users, The Energy Project, NW Energy Coalition, Federal Executive Agencies and the Sierra Club filed a "Joint Petition to Modify Order 07" in Dockets UE-121697 and UG-121705. After a hearing on March 17, 2016, the Commission granted the parties' petition, directing PSE to file a general rate case by January 17, 2017. In that rate case, PSE commits to address the future of Colstrip including:

- a depreciation schedule for all four units that aligns with the plants' useful life;
- an analysis of Units 1 and 2 that includes known major maintenance obligations and their projected costs;
- a narrow window of dates for the planned retirement of Units 1 and 2;
- detailed information regarding planned decommissioning and remediation activities for Units 1 and 2, including costs associated therewith; and
- a basic framework for how power replacement decisions will be made if the planned retirement of Units 1 and 2 is out of sync with the development of the 2017 Integrated Resource Plan.²⁹

VI. Natural Gas Resources

The Commission considers PSE's approach to natural gas modeling and the reasoning applied to model results to be sound. The IRP identifies a gas shortfall of 25 MDth/day beginning in the winter of 2016-2017 and increasing to 415 MDth/day by the winter of 2034-2035. As a point of reference, PSE's current gas system capacity is just under 1,000 MDth/day.

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

- demand-side resources;
- the proposed PSE LNG peak-shaving facility, located at the Port of Tacoma to serve the needs of PSE and as marine fuel;
- expansion of the Westcoast Pipeline and associated expansion of Northwest Pipeline (NWP);
- expansion of Northwest Natural's Mist storage facility;
- upgrades to the existing Swarr propane-air injection peaking facility;
- proposed cross cascades pipeline expansions; and
- the proposed Kingsvale-Oliver reinforcement project.

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

²⁹ Dockets UE-121697 and UG-121705, Joint Petition to Modify Order 07 ¶ 8 (March 9, 2016).

Table 2
Gas Resource Plan, Cumulative Additions in MDth/Day of Capacity³⁰

	2018-2019	2022-2023	2026-2027	2034-2035
Demand-Side Resources	12	29	46	69
PSE LNG	69	85	85	85
Swarr Upgrade	30	30	30	30
Westcoast/NWP Expansion	0	34	49	102
Mist Storage Expansion	0	0	50	50
Cross Cascades to AECO Expansion	0	0	10	10
Cross Cascades to Malin Expansion	0	0	0	99

Historically, the Sumas hub at the Canadian border has been a liquid market with excess pipeline capacity from the production fields to the north, so PSE acquires firm pipeline capacity on the Westcoast pipeline to meet half of its need at Sumas.³¹ In the 2015 IRP, PSE claims that it “cannot rely on spot market supplies at Sumas to meet our peak loads.”³² There is no analysis in the IRP to support this conclusion, though PSE’s presentations show that that Westcoast has limited winter capacity available.

- PSE’s 2015 IRP does not contain sufficient information to allow the Commission evaluate the availability of pipeline capacity on Westcoast. In the next IRP cycle, PSE should revisit the availability of pipeline capacity and utilization with the advisory group. In every IRP, PSE must include documentation and analysis to support any significant changes to its plan.

VII. Conclusion

The Commission acknowledges that Puget Sound Energy’s 2015 Electric and Natural Gas Integrated Resource Plan complies with WAC 480-100-238 and WAC 480-90-238. PSE should not rely on its proposed planning margin as justification for procuring a new resource at this time. Further, the Commission recommends that PSE employ models for use in all future IRPs that fully account for capital investments in thermal plants and system flexibility. The Commission expects PSE to follow the recommendations outlined in this letter as it develops future IRPs.

³⁰ PSE 2013 Integrated Resource Plan, page 1-24, figure 1-12.

³¹ September 25, 2014 PSE IRPAG Presentation, at 55.

³² PSE 2015 IRP, page 7-3.