Attachment

Utilities and Transportation Commission Comments on

Puget Sound Energy's 2011 Integrated Resource Plan

Dockets UE-100961 & UG-100960

As an electric and 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. This responsibility is particularly important in an era of uncertain greenhouse gas (GHG) mitigation costs, wavering load growth and the lure of low natural gas prices. The planning requirements specified in WAC 480-90-238 and WAC 480-100-238 are intended to help each utility develop a strategic approach to navigate marketplace opportunities and risks based on that utility's unique attributes. PSE's 2011 Integrated Resource Plan (the Plan) represents such a strategic approach. As such, it is consistent with the Utilities and Transportation Commission's (Commission) planning regulations. Below we discuss how the Plan addresses the requirements for integrated resource plans (IRP).

General Observations

PSE's analysis of resource needs over the 20-year time span is comprehensive, and its consideration of inputs, analytical modeling, and analysis of results is good. While the quantitative analysis and modeling are well executed, there are certain parts of the Plan that need more explanation of the Company's reasoning and how it developed its conclusions. For example, the discussion of how the Company chose its Preferred Resource Portfolio (PRP) lacks a clear connection to the Company's statements in technical advisory group meetings that market prices for power available to the Company will, in most hours, reflect the lower price that is the result of the market price being determined by the more efficient, lower heat rate of a combined-cycle combustion turbine (CCCT). The Company intends to use the expected lower market prices to shelter ratepayers from the exposure of serving load with the less efficient single-cycle combustion turbines (SCCT or peakers) that the Preferred Resource Portfolio relies on heavily to meet its capacity needs over twenty years.

The Appendices of the Plan provide useful descriptions and documentation with quantitative and qualitative detail supporting the chapters of the Plan. Yet in some areas the Company should explain better how and why it chose certain inputs and assumptions for the modeling. For example, in Appendix H concerning demand forecasts, the

Company does a good job in describing the methodology, key assumptions, and the load forecast models on the electric and gas sides. However, as is discussed later, it is not sufficiently clear how the Company's choices of inputs or forecasting methodology affect the final results of the load forecast. Since the results of the load forecasts are such critical components of the overall Plan, it is important that the Company make clear the basis of its choices and how they influence the ultimate results.

Because of this lack of explanation of the connection between the Company's choice of inputs for the model and the model's output in the development of the PRP, the Plan may not be as useful in helping the Company adapt its resource planning to external changes and the business environment as it meets its load. Since the planning environment is dynamic and constantly changing, especially in the context of public policy requirements, the inter-relationships between the Company's assumptions and the output of the models should be made as clear as possible. An IRP should act as a guide and as such should clearly identify the items that, if changed, would change the timing or resource acquisitions identified in the Plan's PRP.

Electric Resources

Electric Demand

The Company's Plan relies on its Base Case scenario that uses the F2010 Base Load Forecast (Base Load Forecast) with an average annual growth rate of 1.9 percent between 2009 and 2014 and a long term growth rate of approximately 2.1 percent. The Base Load Forecast projects an annual peak growth rate of 1.6 percent. The Plan explains that the overall peak growth is slower than the overall average-use load growth due to a higher projected growth in commercial load relative to the residential load, which is more sensitive to temperature. This relationship is driven by the commercial customer load growth of 2.5 percent. Unfortunately, the Plan does not specifically address the relationship between the load model inputs and their effect on the commercial peak load growth rate. Job creation and unemployment rates are key determinants in modeling load growth. The Plan assumes a faster rate of job creation of 1.4 percent than the 15-year historical growth rate of 1.1 percent that includes the effects of the recent economic recession. The Plan also states that commercial loads related to non-manufacturing employment are expected to grow relatively faster, while industrial loads will continue to decline. With no more discussion provided in the Plan, we conclude the commercial peak load growth may be reasonable, but has tenuous support in Plan.

Moreover, in Chapter 4, the Plan sets forth an explanation for the occasional mismatch between load forecasts in the IRP and those used in general rate cases (GRC). It states that since the load forecast is so central to the IRP analysis and due to the long lead time to finalize IRPs, it is not possible to update load forecasts in the IRP context in order to synchronize them with the load forecasts used in rate cases. The Company states that it will always use the most recent load forecast when it presents evidence in a rate case or makes a resource acquisition. We understand the lag between the IRP load forecast used to develop the IRP and updated forecasts used for the Company's operation and in its GRC. However, the load forecasts in the IRP should specify enough future scenarios to encompass possible updated forecasts.

- In its next IRP, the Company should identify the IRP load forecast most similar to its updated forecasts as part of the IRP's 2-year action plan.

- The Company should list the input assumptions to its load forecast model, especially for the expected growth in commercial loads, and explain the bases for those assumptions.

In addition to the base case, the Plan models four alternative load forecasts for both the electric annual load and the peak load: a) "cyclical" alternate low; b) "cyclical" alternate high; c) "structural" alternate low; and d) "structural" alternate high. We find these alternative scenarios useful when considering an uncertain future. Figure H-3 in Appendix H shows demand growth in the Low "Cyclical" Alternative as diverging from the Base Load Forecast primarily during the 2010-2016 period of the 20-year projection. However, long-term term growth between the two scenarios is nearly identical. Due to the prolonged recession in the current economic cycle, we find the 2010-2016 portion of the scenario plausible and urge the Company to give adequate weight to this forecast as it acquires additional resources during this period of time. However, we are skeptical of the element of the scenario's design that has "most of the recovery to the 2010 Base Case scenario complete by 2016."[1]

It is interesting to note that the high and low alternative "cyclical" load forecasts begin at the same point as the 2010 Baseline forecast but have different slopes. Although we note

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[1] PSE 2011 IRP Appendix, H-7.

that the current economic recovery is quite sluggish, we nevertheless encourage the Company to continue to model both high and low alternative load forecasts based on economic cycles. We find both analyses useful as they describe the upper and lower limits of load growth forecasts in an uncertain economic period. We find the low alternative load forecast a useful sensitivity and give it a significant weighting in our consideration of PSE's load growth.

Appendix H also models two "structural" alternatives for forecasting loads, high and low, based on a more fundamentals-type approach focusing on population growth, job creation, and other non-economic cycle components of economic growth. We find this analysis relevant and useful as well. In the Structural Alternate Low Forecast, the slope of the average demand is much lower than the slope in the 2010 Baseline forecast through 2019, which is primarily due to lower long-term population growth. While the load projection in the Structural Alternative Low Forecast may be well below what PSE considers the expected range, we find this to be a useful perspective on the potential for lower-than-expected growth. We encourage the Company to keep this more structural perspective in mind as it considers additional resource acquisitions.

We also note two unexplained results regarding peak and average loads in the Low Cyclical and Low Structural Alternative forecasts that appear to be counterintuitive and are illustrated in Figure H-3 and H-4. While the Low Cyclical Alternative shows distinctly lower average load growth through 2015, the Plan does not show a corresponding lower growth in the Low Cyclical Alternative in the peak demand for the same period. Second, the Low Cyclical Alternative shows a higher peak demand for that same period than the Low Structural Alternative in the 2010 to 2015 period, while the situation illustrated on the graph reverses for the 2016-2019 period. These two discrepancies are not explained along with how the economic factors, including the interplay of cyclical and structural components of economic growth, would lead to this result.

- Future IRPs should provide explanations for the results of models including any seemingly apparent discrepancies between the scenarios, such as the low structural and cyclical forecasts.

Demand Side Resources

The Plan identifies Demand Side Resources (DSR) as the only resource that both lowers costs and risk. We agree with this assessment and note that a more rapid ramp rate improves the cost-effectiveness of these measures.

PSE hired the Cadmus group to examine demand side resources, including the development of two ramp rates for DSR.[2] One ramp rate is based on the Northwest Power and Conservation Council's ramp rate in its 6th Power Plan and another rate, dubbed the PSE 10-year ramp rate, is more aggressive. The Plan concludes that the PSE 10-year ramp rate did not result in more DSR being adopted over the 20-year horizon but does result in DSR being adopted much earlier resulting in a greater MWh savings. The Plan states that PSE's 10-year ramp rate also lowers the 20-year expected increase in revenue requirement and that by using it the cost effectiveness of the DSR measures are improved. We agree with these benefits of the higher PSE 10-year ramp rate.

The Plan analyzes DSR measures in groups called bundles that span a price range. For its PRP, the Plan chooses Bundle E. Only in one scenario of PSE's scenarios, the "Green World" scenario does the Plan select a DSR bundle higher than Bundle E. Though the Plan does not include a discussion of the slope of the DSR supply curve, from the PowerPoint slides provided in the August 11, 2011, open meeting we are aware of the inclining cost curve for the DSR bundles. We also recognize that PSE's Plan has considered all the measures included in the Northwest Power and Conservation Council's methodology.

We concur with the Northwest Energy Coalition's observations that the Plan demonstrates that DSR significantly reduces the need for renewables over the 20-year Plan. This is well illustrated in the graph shown in Figure 5-3 setting forth the Company's RPS compliance needs over the 20-year period under the acquisition strategy of the preferred Bundle E of DSR measures. Figure 5-3 shows that the Base Case without DSR requires 300 more MW of wind and 25 more MW of biomass over the 20-year planning horizon.

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[2] A DSR Ramp rate is the rate at which conservation measures are installed or adopted by the utility's customers.

Electric Analysis

The Plan's PRP calls for the addition of 2,443 MW of SCCT's and the addition of no CCCTs during the 20-year planning horizon. We note this is a significant financial and resource commitment by PSE to a particular type of resource. The preferred portfolio calls for many of these peakers to be acquired throughout the 20-year period, including a commitment of 1,278 MW by 2020. It also calls for 50 MW of biomass, 500 MW of "transmission and market," and 400 MW of wind during the 20-year planning horizon.

We conclude that the Plan contains a comprehensive explanation of PSE's existing resources and of the cost of generic resources from which the model may select. However, it does not adequately describe how the price assumptions for various generic resources might alter final selection of preferred resources. For instance, the Company estimates that the capital costs of a CCCT is approximately 50 percent more expensive than a SCCT but does not provide analysis showing at what price point, if any, the model might select a CCCT instead of a peaker.

- In its next IRP, the Company should identity a few key cost inputs and perform trigger point or sensitivity analysis on those inputs in developing the PRP.

Sierra Club comments that in its next IRP PSE should model the shutdown of Colstrip and add a sensitivity that includes future regulatory costs of operating Colstrip. PSE provides a useful critique of its modeling of a "no northwest coal" scenario. We agree with PSE's commitment to study the modeling of this scenario. We also conclude additional modeling of Colstrip scenarios in PSE's next IRP would be useful.

- PSE should 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.

- PSE should conduct a broad examination of the cost of continuing the operation of Colstrip over the 20-year planning horizon, including a range of anticipated costs associated with federal EPA regulations on coal-fired generation.

We also note that the Company acknowledges that carbon dioxide (CO_2) costs are one of the key inputs for modeling, along with load forecasts (demand), wholesale power prices, and natural gas prices. We find the inclusion of several levels of CO_2 costs to be appropriate, and further acknowledge that such modeling is required by our rules in WAC 480-100-238(2)(b) to consider the environmental effects of future generation resources. In its analysis of CO_2 prices, the Company modeled three different levels of prices (low, moderate, and high) and developed scenarios based on the variability of this key assumption along with others (base case, base case plus CO_2, and "green world"). We note that the regional and national discussion regarding setting a price for CO_2 remains unsettled, and therefore significant uncertainty still exists for developing a preferred mix of electric resources. We find the Company's description of the risks associated with CO_2 pricing to be relevant and find its analysis of the various scenarios to be useful.

We consider the analysis summarizing six broad themes in the Key Findings and Insights section of Chapter 5 to be thoughtful and cogent. We find the discussion of the cost-versus-risk trade off in the replacement of peakers with CCCTs in the Preferred Resource Portfolio to be informative. Equally, we find the topic of margins generated by a portfolio of peakers versus CCCTs which the Company illustrates in Figure 5-21 to be valuable. We agree with the Company's statement here that "[t]he net cost of a CCCT plant is significantly affected by the margin it generates, and that margin varies as market conditions change."[3] However, this comparison could be more effectively presented and explained, since the key distinction appears to be the relationship between the margins produced by CCCTs and peaker plants that vary greatly depending on wholesale market conditions in the Western region.

Moreover, since the PRP places such a heavily reliance on peaker plants, we believe that the Company needs to provide a more in-depth analysis of the range of benefits that these plants bring to the Company's preferred portfolio. Peaker plants generally have cheaper capital and fixed costs compared to CCCTs, and are easier to ramp up and down operationally to meet variations in load. Yet its thermal efficiency is less than a CCCT. A peaker may also offer benefits to firm up the Company's expanding portfolio of variable wind generation, especially its ability to ramp up quickly within the hour when balancing authorities still largely schedule by the hour. Yet such benefits, if any, of firming up intermittent resources are not explicitly or adequately explained in the Electric Analysis in Chapter 5.

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[3] PSE 2011 IRP, H-15.

- In its next IRP, the Company should strive to explain what factors drive cost, value (off-system sales revenues, or avoided purchases of electricity or natural gas) and risk in the model and in the preferred PRP the Company selects.

- Even though a future of low priced natural gas may be an increasingly held view, the Company should continue to model sensitivities under high gas conditions to present upper-end risk analysis.

- Finally, the Company should make more explicit any load following and ancillary benefits associated with peakers, such as firming up variable generation in its portfolio.

Regarding transmission needs, Chapter 5 only briefly describes the model's selection of 500 MW of transmission in the PRP that is labeled "transmission and market." We find, however, that Appendix E provides a well written and descriptive discussion of transmission issues and options. It mentions the expansion of West of Cascades North as the primary flowgate that PSE could develop, in coordination with the BPA system. However, the statements in Appendix E about possible transmission upgrades are quite general and do not completely explain the basis of the selection of 500 MW of transmission in conjunction with wholesale market resources. In addition, Appendix E lists PSE's transmission request to BPA in the 2008 Network Open Season for 150 MW of Cross Cascade transmission, but fails to discuss if that is included in the PRP's stated resource need of 500 MW by 2020.

- In the next IRP, the Company should discuss in more detail its transmission expansion needs, especially for the Cross Cascades-North route, and how such planning and possible expansion of specific transmission routes will benefit the Company's resource needs in the PRP.

We note that the Company does not include any discussion of the various types of electric storage technologies in its Plan or in the detailed Appendices which examined various fossil and renewable generation technologies. We understand that the Company, in Chapter 5, chose not to study certain renewable technologies due to their relatively high cost and market immaturity. But we believe that the Company's next IRP would be well served by a discussion of electric storage technologies, and why they may or may not fit into the Company's resource portfolio.

- In its next IRP, the Company should include in its next IRP a discussion of the technologies of electric storage, their cost-effectiveness, commercial availability, and proper classification compared to other forms of generation.

The PRP identifies the addition of 300 MW of wind by 2020 to comply with PSE's renewable resource obligations for 2020 under the Energy Independence Act (EIA). The EIA also provides that:

> A qualifying utility shall be considered <u>in compliance</u> with an annual target created in RCW 19.285.040(2) for a given year if the utility invested four percent of its total annual retail revenue requirement on the incremental costs of eligible renewable resources, the cost of renewable energy credits, or a combination of both, but a utility may elect to invest more than this amount.[4]

As expressed in our Policy Statement on acquisition of renewable resources, we consider the EIA renewable resource requirement to be a resource need.[5] Therefore, compliance with that resource requirement must be part of an IRP. Since the EIA provides a means of compliance based on the utility meeting certain investment thresholds, it follows that utilities should consider that compliance path in their IRPs. PSE has done so and clearly shown that the investment threshold has not been met for the 2020 requirements, regardless of the imperfections that may accompany PSE's analysis.

However, the IRP process is not the venue for determining the financial analysis that comports with the law. The IRP is a planning document to guide the utility's actions. Proceedings that determine a utility's compliance with the EIA are more appropriate for determining the law's application.

We find the Action Plan for electric resources in Chapter 1 to be a useful summary of several areas, but it is quite general and describes activities at a high level. If the Company intends to pursue a specific resource acquisition, it needs to state in its Action

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[4] RCW 19.285.050(1)(a) (emphasis added).

[5] *In the Matter of the Washington Utilities and Transportation Commission's Inquiry on regulatory Treatment for Renewable Energy Resources*, Report and Policy Statement Concerning Acquisition of Renewable Resources by Investor-Owned Utilities, Docket UE-100849, issued January 3, 2011.

Plan the resource capacity it is seeking. While the Company may qualify its Action Plan by indicating that it may ultimately choose not to acquire a generic type of resource, it should state specifically its basis for such a resource to be acquired under the Action Plan.

Gas Resources

Gas Demand

The Plan projects peak gas demand to grow at 1.9 percent and natural gas load to grow at 1.5 percent over the next 20 years. The Plan's rate of growth for the projected natural gas load is lower in the 2010-2013 period due to lower household formation. We agree with this but are also concerned that household formation may continue to be weak beyond 2013.

The gas demand scenarios include the same type of "cyclical" and "structural" alternatives as used in the electric load forecast and our comments on the alternatives made in the electric load modeling apply to natural gas load modeling as well.

The Gas Forecast Highlights section in Appendix H of the Plan includes clear descriptions and useful summary tables in Figures H-12 through H-15. We find the forecasts in the Base Case to be reasonable.

- The next IRP should tie its conclusions on peak load growth and gas customer counts to the granular data that support the statements. For example, PSE should detail more clearly the linkage between "customer growth is expected to be weak in the near term due to lower household formation" and the numbers for lower household formation.[6] In addition, since it is not clear if the gas load projection is using the same household formation numbers as the electric load projection, the Company should clarify that point in the next IRP.

Gas Analysis

We consider the Company's natural gas analytical modeling and reasoning applied to the model results, as outlined in Chapter 6, to be good. We view the use of "price-jump

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[6] PSE 2011 IRP, H-15.

statistics" to model infrequent one day price "blow-outs" as a good modeling initiative, though continued refinement may be necessary.[7]

The modeling provides independent analysis of the gas resource needs for "gas for retail" sales and for "gas-for-power" (gas for electric generation). It also provides a combined gas resource need assessment. We find the combined analysis to be very useful, but not a substitute for the separate analyses.

In the Plan's Base Case Forecast used to determine the PRP, the Company has the resources to meet peak day need until the winter of 2015-2016. In the Low Growth Forecast, the Company does not need additional resources until the winter of 2017-18.

- We encourage the Company to carefully track actual load growth to assess if resource needs are trending with the Base Case or the Low Growth Forecast.

The gas-for-power analysis uses three Base Case scenarios: all-peaker, all peakers replaced with CCCT, and a thermal mix of peakers and CCCTs determined by limiting market exposure to 40 percent. We consider these to be appropriate and useful scenarios.

The all-peaker Base Case assumes that no firm gas transport is necessary. While we are not eager to see PSE burdened with the cost of year-round firm transport capacity, we are not yet convinced the Company has all the operational mechanisms that will assure PSE can dispatch, at any time necessary, its planned peakers to meet load obligations under a scenario without firm gas transport. We conclude that the Company will need to employ more operational logistics than are described in the Plan in order to assure the dispatch of peakers that do not have firm gas capacity, even in the case where PSE adds only two or three peakers to its generation fleet.

We believe the Plan's description of existing resources to be clear and comprehensive. The five gas resource alternatives are also well thought out and appropriate. The modeling results clearly prefer additional NW Pipeline capacity by 2021 compared to the alternative of additional regional liquid natural gas storage or the cross-Cascade pipeline. With the Company's need for new peak capacity in the 2015-2016 timeframe (or in the 2017-2018 timeframe with low gas growth demand), we conclude the Company has

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[7] PSE 2011 IRP, J-6.

sufficient time to consider the lowest reasonable cost option before committing to a project.

The Plan states that when the Company applies its accelerated 10-year ramp rate, the DSR economic potential in the Plan is only slightly lower than it was in the 2009 IRP gas sales Base Case. Considering the fall in natural gas prices since the 2009 Plan, we consider the DSR bundles reasonable. We reiterate, however, that IRP planning requires pursuit of all cost-effective conservation.

We consider the five summary items described in the Key Findings section of Chapter 6 to be well described and reasonable. We also find the Action Plan for gas sales resources listed in the Executive Summary of Chapter 1 to be reasonable. However, as with the Action Plan for electric resources, we consider the gas action items to be described in a fairly general level for both demand-side and supply-side resource actions to be taken in the near term. We agree that better coordination on fuel supply planning is necessary and that additional regional storage resources may be required to address the needs for generation.

Conclusion

The Commission acknowledges that Puget Sound Energy's 2011 Electric and Gas Integrated Resource Plan complies with WAC 480-100-238 and WAC 480-90-238.