NW Natural Gas Company's 2013 Natural Gas Integrated Resource Plan
Docket UG-120417

As a natural gas distribution utility operating in Washington, NW Natural Gas Company (NW Natural or Company) has a fundamental responsibility to manage the risks and opportunities associated with acquiring and delivering natural gas on behalf of its customers. This responsibility is particularly important in an era of uncertain load growth. The planning requirements specified in WAC 480-90-238 are intended to help each natural gas utility develop a strategic approach to navigate marketplace opportunities and risks based on that utility's unique attributes.

NW Natural's 2013 Integrated Resource Plan (Plan) includes a strategic approach based on the Base Case peak day demand analysis that results in the resource additions shown in Table 1.1 of the Plan. 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).

Gas Requirements Forecast

The Company expects an average annual load growth rate of 1.27 percent (net of demand side management (DSM)) on a system-wide basis for the 20-year planning horizon and an average annual load growth rate of 1.61 percent for Washington, net of DSM. The Company expects the average annual peak day load growth rate, net of DSM savings, to be 0.92 percent on a system-wide basis for the 20-year planning horizon and to be 1.62 percent for Washington. The Company projects a customer growth rate of 1.57 percent for Oregon and a 2.30 percent growth rate for Washington.

The Company reports that customers in the Portland, Oregon, area represent approximately 61 percent of its customer base and customers in Washington represent approximately 10 percent of the base with the remaining customers in western Oregon. NW Natural relies on the Oregon Office of Economic Analysis (OEA) as well as the Northwest Power and Conservation Council to develop its forecasted load data. In previous IRPs, the Company has stated that it relies on OEA data for the Portland area to develop a projection for the Vancouver, Clark County, and adjacent Washington service territory. The Company showed in its response to staff comments on the draft IRP that the OEA data from 2007-2011correlates well with Washington Economic and Revenue Council data from the same period. Through this, the Company has shown, at least in the near term, that OEA data are as reliable as the Washington data in predicting customer growth in the Company's Washington service territory.

In its comments on the Company's previous IRP, the Commission requested that the Company provide an analysis of the factors that drive the differential in expected growth rates between the Portland and Clark County service territories. The Company provided information in this IRP to show that the expected growth rates are driven by lower market penetration in Washington as compared with Oregon, and a large number of new housing developments being built in the greater Vancouver area.

The Company includes Low Growth and High Growth Cases for its customer forecast. The Low Growth Case shows a much lower rate of load growth than the Base Case during the 2013 to 2021 timeframe with a return in 2023 to the growth rate of the Base Case. At this point, in which the region is seeing a slow economic recovery after a period of significant economic recession, both portions of the Low Growth Case seem reasonable.

<u>Supply-Side Resource</u>

The Company uses the linear programing model SENDOUT to develop its Plan. The Company thoroughly describes its existing resources, and includes a comprehensive list of typical traditional future available resources from which the model may choose to meet additional load. It does not include in its Plan resource options that are aimed at reducing major component outages.

In April, 2011, the Company entered into agreements with Encana Oil and Gas Inc. (Encana), under which the Company and Encana agreed to participate in a joint venture to develop gas reserves in the Jonah Field, located in the Green River Basin in Sublette County, Wyoming. In the agreements, the Company pays a portion of the costs of drilling in the Jonah field, and in return receives rights to the production of gas from certain sections of the field. The Company expects the venture will help provide its Oregon utility sales customers with long term supplies at stable pricing over about a 30- year period.

Consistent with the Commission's Order 05 in Docket UG-111233, the Company does not include the costs or benefits associated with this joint venture in rates for its Washington customers. Instead, NW Natural maintains two separate portfolios for Oregon and Washington for tracking purchased gas adjustments in each of its regulatory jurisdictions.

As in the 2011 IRP, the Company decided not to model specifically the gas acquisition options based on the expected price of gas from the Encana transaction, stating that doing so would be problematic and unhelpful. The Company states that, for multiple reasons, the Encana transaction does not specifically alter the modeling or analysis of supply options from what would be shown in the absence of the Encana joint venture. We agree that not including the Encana joint venture as a supply-side resource in this IRP is the better course of action.

The Company's distribution system accesses Northwest Pipeline (NWP) with connections on the Interstate 5 north-south line and the east-west line through the Columbia Gorge. This is the system's only interconnection with interstate pipelines. Because of the availability of Wyoming gas, and given the Company's reliance on the NWP for all its interstate gas supplies, the Company partnered with TransCanada Corporation to form Palomar Gas Transmission LLC (Palomar), which proposed to develop, build and operate a pipeline connecting Gas Transmission Northwest's (GTN) mainline north of Madras, Oregon, to the Company's system in Molalla, Oregon. In late 2008, Palomar filed with the Federal Energy Regulatory Commission (FERC) an application for a certificate to build and operate the pipeline. In early 2011, Palomar withdrew its FERC application with the expectation of refilling it at a later date. In late 2012, in collaboration with NWP, project sponsors announced the reformulation of Palomar/Blue Bridge into a new cross-Cascades pipeline project called the Northwest Market Area Expansion (N-MAX).

The integrated project sponsors (TransCanada, NW Natural, and NWP) have continued to work collaboratively to develop a single Cross-Cascades project for the 2017-2020 timeframe. Since the open season process failed to secure sufficient subscriptions from potential customers, the project consortium suspended further development work. The Consortium has identified 2018 as its preferable in-service date for the project if sufficient subscriptions from shipping customers can be secured. Should the project be completed, the Company has indicated that it would be in a position to turn back some existing NWP capacity.

Demand Side Resources

NW Natural provided the Commission with its 2013 Energy Efficiency Plan (Efficiency Plan) and implementing tariffs on November 29, 2012.

At the recessed open meeting on December 21, 2012, the Commission acknowledged receipt of the Efficiency Plan and allowed the proposed revisions to the 2013 calendar year program goals and budget tariff to go into effect. Within the Plan, the Company outlined its expectations to acquire between 220,421 and 259,319 therms of savings in 2013, at a cost of between $1.4 million and $1.6 million.

The Company provides a copy of the current Efficiency Plan as a part of its 2013 Integrated Resource Plan. NW Natural consults regularly with its advisory group, and uses periodic tariff filings to update its programs, as well as filing quarterly reports on energy efficiency achievement. The Efficiency Plans are processed as attachments to the periodic tariff changes. Based on the current Efficiency Plan, the Company proposes a cost-effective, achievable potential of 6.2 million therms within its Washington service territory over the 20-year planning period from 2013 to 2032.

Resource Choices

In its Plan, the Company performs two separate analyses to determine its resource needs on a portfolio basis. One is the traditional gas industry analysis (Base Case) to determine the resource needs for meeting peak day demand. The other is a new approach using a reliability risk analysis that models major outages to coincide with the peak or near-peak day demand. The Company relies on the latter to arrive at its Preferred Portfolio.

The Base Case Analysis. In the traditional Base Case analysis, the probability of one or more major outages coinciding with the peak or near-peak day demand is low enough that it does not contribute significantly to the loss of load probability.

The Base Case's analysis concludes that Mist recall (the increased use of physical storage in the Company's storage facility in Oregon) is the least-cost means for cumulative resource additions for at least the first 13 years of the 20-year planning horizon. It calls for reliance on Mist recall in steadily increasing amounts, starting at 17 MDT/day in 2018-19 and rising to 44 MDT/day by 2021-22. This is the major resource addition that the Base Case calls for during the planning period, relying on additional cross-Cascades pipeline capacity toward the end of the planning period.

The Reliability Risk Analysis. This non-traditional reliability risk analysis assumes a major component outage will occur on the peak day or near peak day demand (high demand) during the 20-year planning horizon. It attempts to answer the questions of what would happen if a major resource outage occurred during a period of high demand and what set of resources would best prevent or limit any resulting interruption of service. The Company models a complete outage of the NW pipeline through the Columbia Gorge. It also models a 25 percent reduction of deliverability from the natural gas Mist storage facility with a 50 percent reduction in the ability to deliver any new incremental Mist storage capacity the model might choose to acquire during the 20-year modeling period.

This reliability risk analysis (Plan 1540) concludes the addition of the cross-Cascades pipeline is the least-cost means of achieving both the necessary reliability and capacity, and assumes that it will be available by 2018-19. It relies heavily on such a pipeline for resource additions, starting at 165 MDT/day and maintaining that level. This compares to the other resource additions of Mist Recall at 21 MDT/day, and the Newport LNG transmission at 40 MDT/day, together with a resource deletion of 77 MDT/day. This is the Company's Preferred Portfolio, and has a net present value that is $64 million higher than the Base Case over the 20-year planning period.

Discussion. These two approaches lead to dramatically different results – relying on storage in one case and building a new pipeline in the other – with different financial impacts.

While the reliability risk analysis has some merit, in our view it is not developed sufficiently for use in guiding the Company's decision making in either the Action Plan or the 20-year planning period. We conclude the resource portfolio derived from the Base Case meets the IRP planning requirements and offers the least-cost, least-risk plan for the Company at this time.

The Company's Base Case analysis assumes that the cross-Cascades pipeline is not built and that the probability of a major outage during a high demand period is small enough that the addition of a cross-Cascades pipeline is not the incremental, least-cost resources for reducing the risk of unmet demand. In our view, this Base Case produces the least cost resource portfolio of any of the modeling results and within an acceptable range of risk. The certainty of Mist Storage recall in terms of price and timing compared to the uncertainty of the cost and timing of building the cross-Cascades pipeline and the effective rates once the pipeline is in service, support this conclusion.

However, should the Company wish to pursue the reliability risk analysis in the future, we would expect the Company to perform additional work to refine its analysis and support its conclusions on the probability of a major outage coinciding with a peak or near peak demand day with the following guidance.

First, the Company should revisit and articulate how it determined the probability of a major outage coinciding with a high demand period and that probability's overall effect on service interruption. The Plan lacks a description of the basis for the underlying assumption that a major outage will occur on a high demand period during the 20-year planning horizon. In response to Commission Staff's inquiries after the Plan was submitted, the Company provided examples of major pipeline outages over approximately the last 15 years. The Company indicated it was unable to obtain accurate information about the frequency of outages from earlier periods. The Company did not specify the geographic area included in its sample that provide the number of outages, the number of pipeline miles in the geographic area, or whether the conditions where the outages occurred are comparable to the section of Columbia Gorge pipeline it analyzed.

Further, it is not clear if these major outages are coincident with the high demand conditions that the Company experiences during the winter season. It is our understanding that slides or land movement, a common cause of a major pipeline outage or de-rating, typically occurs during times of warm wet weather, rather than cold dry weather typical of high demand periods. If the Company pursues its reliability risk analysis we expect that the Company will provide such detailed information on land movements, broken down by seasons and topography and its applicability to the Columbia gorge area.

Second, the relationship between the major outage event and the number and duration of customer outages needs to be established. The Commission recognizes the difficulty of establishing an accurate prediction but views those challenges as all the more reason to clearly establish and specify in the IRP the methodology for doing so.

Third, the Company should consider alternative actions to reduce the probability of major outages during a high demand period. The Company did not include in its Action Plan the proposal to work with NW Pipeline to reduce or ameliorate outages on the Columbia Gorge section of the pipeline. It is possible that such actions could reduce the un-served demand in the Company's reliability risk analysis to a level that would not require the cross-Cascade pipeline to be built. Similarly, the Plan did not articulate or document the Company's analysis of measures to reduce or ameliorate outages at the Mist storage facility or to analyze the value of redundancy in compressor capacity or pipeline takeaway capacity.

Within the reliability risk analysis the Company develops two approaches called the Resource Redundancy and Resource Diversity options. If the Company conducts a reliability risk analysis in its next IRP, the Commission recommends the Company consider the following.

- One of the options for additional resources (in light of reliability and cost) that the Company is considering over the planning horizon is a large amount of recall of storage at the Company's Mist facility. This scenario is referred to as the "Resource Redundancy" option, which simply adds more resources while optimizing lowest costs. As part of this option, the Company acknowledges that for this to be a viable option, an eastside transmission loop is necessary to move gas to the east Portland load center. To a large extent, this relies on more extensive use of existing available resources and entails low development risks. The Company notes that it requires additional analysis before committing to this option.
- A second general option the Company is considering for additional resources is defined as the "Resource Diversity" option, through which the supply of gas is diversified through pipeline diversification, by replacing a portion of the Company's capacity on NWP's pipeline through the Columbia Gorge with capacity from a new cross-Cascades pipeline. The Company acknowledges that for this option to be economically viable, a new Cross Cascades pipeline would need to be developed as a regional project. The Company states it can act as a catalyst for the project, but based on its resource needs, it can only justify the cost by subscribing for 35-40 percent of the overall estimated capacity of such a project.

The Company should further analyze the additional, non-monetized potential benefits from a more diversified supply portfolio. Potential benefits from the addition of the cross-Cascades pipeline are dependent on uncertain future events including:

- Future significant price differences between Canadian and Rockies gas
- Possible increased demand for Canadian gas due to liquefied natural gas export terminal development

These factors should be evaluated and as outcomes and market trends become clearer, the Company should incorporate the new data into future IRP analyses.

In addition to these refinements, the Company should consider, with Commission Staff assistance, a broader approach to the risk reliability analysis. The Company performed the reliability risk analysis in the context of just its operations. However, the least-cost approach will probably be found through a multi-utility planning analysis. The Company compares the outage scenario it presents to contingency planning for electric transmission grids, and there is some merit to that analogy. Transmission reliability planning is done across multiple balancing authorities due to the interdependency of the systems, and to achieve an overall least cost approach for a group of utilities. This method and result would seem true for local gas distribution companies too. An outage of the Columbia Gorge section of the NW pipeline during a high-demand period would affect more natural gas utilities than just NW Natural. Also, the increased dependency of electric power generation in the western United States on natural gas as a fuel has lead FERC to examine the electric gas interdependencies. If the Company considers that the probability of a major outage coinciding with a high-demand period may significantly contribute to unmet residential demand, working with other natural gas and electric utilities in the region would provide the best opportunity to find a least-cost solution for the Company and the region.

Conclusion

The Commission recognizes that the Base Case analysis and results fulfill the requirements under the IRP rule, and acknowledges that NW Natural’s 2013 Natural Gas IRP complies with WAC 480-90-238. However, the Commission has significant questions regarding the risk reliability analysis that led to the Company’s Preferred Portfolio, and whether, that analysis is developed sufficiently to guide the Company’s investment decisions.