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September 30, 2005

VIA FILING CENTER

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ATTN: Filing Center

Re: DOCKET UM 1056: Investigation into Integrated Resource Planning Requirements

Reply Comments of NW Natural

Enclosed for filing are NW Natural's Reply Comments in the above-referenced docket.

Please contact me if you have any questions.

Sincerely,

/s/ J. Ross

Joseph M. Ross
Rate Economist/Planning Analyst

kcm

enclosures

cc: UM 1056 Service List

Staff's Proposed Guidelines
Integrated Resource Planning for Energy Utilities[1]
Docket UM 1056

1. The plan must meet four substantive requirements:

   One, all resources[2] must be evaluated on a consistent and comparable basis.

   - All known resources for meeting the utility's load must be considered, including supply-side options, which focus on the generation, purchase and transmission of power – or gas purchasing and transportation – and demand-side options, which focus on conservation and demand response.
   - Utilities should compare resource fuel types, technologies, lead times, in-service dates, durations and locations in portfolio risk modeling.
   - Consistent assumptions and methods should be used for evaluation of all resources.
   - The real after-tax marginal weighted-average cost of capital should be used to discount all future resource costs.
   - Utilities should analyze how their preferred portfolio would change over a range of reasonable discount rates.

   Two, uncertainty must be considered.

   - At a minimum, utilities should address the following sources of uncertainty:
     – Electric utility plans should address load requirements, hydroelectric generation, plant forced outages, natural gas prices and electricity prices.
     – Natural gas utility plans should address sources of demand ~~(peak, swing and base-load)~~uncertainty, commodity supply and price, and transportation availability and price.
   - Utilities should identify in the plan any additional sources of uncertainty.
   - The analysis must recognize the historical variability of these factors as well as future scenarios.

   Three, the primary goal must be the selection of a mix of resources with the best combination of expected costs and risks for the utility and its ratepayers.

   - The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities also must consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource.
   - Utilities should use present value of revenue requirements (PVRR) as the key cost metric. The plan should include analysis of current and estimated

[1] Unless otherwise indicated, the guidelines apply to both electric and natural gas utilities.
[2] "Resource" is the general term used throughout this document for an option that meets customers' energy needs. For electric utilities, that includes power purchases, generating facilities and fuel, and transmission. For natural gas facilities, that includes gas supply purchases, transportation and storage facilities.

future costs for all long-lived resources such as power plants, gas storage facilities, and pipelines as well as short-lived resources such as gas supply and short-term power purchases.

Comment: The term Total Resource Cost (TRC) should be used here to avoid problems in inter-fuel cost comparisons. For example, subsidies to deal with the above market cost of new renewable resources discussed at page 19 (pagination in original document) present a problem. Unsubsidized TRC belongs in fuel switching analsysis – not cost reduced by subsidies. Similarly, economic credits discussed at page 5 should be excluded in evaluating TRC for resources subject to credits. Such credits may reduce the PVRR and rates experienced by electric customers, but must be removed for inter-fuel cost comparison purposes.

- To address risk, the utility should at a minimum:
  - Use two measures of PVRR risk: one that measures the variability of costs and another that measures the severity of bad outcomes.
  - Discuss the proposed use of physical and financial hedging and their impact on costs and risks.
  - Analyze the effect of potential compliance costs related to global warming on costs and risks for the resource portfolios under consideration, as well as risk mitigation strategies.
- The utility should explain how its resource choices appropriately balance cost and risk.

Four, the plan must demonstrate that it is consistent with the long-run public interest as expressed in state of Oregon and federal energy policies. (Issues 2a, 3, 4 and 5)

2. The utility must meet these procedural requirements:
   - The public must be allowed significant involvement in the preparation of the plan.
     - Participation must include opportunities to contribute information and ideas as well as to receive information. It also must include the opportunity to make relevant inquiries of the utility formulating the plan.
   - The utility should make public in the plan any information that is relevant to its resource evaluation and action plan. At the same time, confidential information must be protected.
     - Information that is confidential when specifically identified may be made publicly available in an aggregated format or through a blinding procedure.
     - The Commission allows information that is exempt from public disclosure under the Public Records Law – for example, trade secrets – to be treated confidentially. Parties may have access to confidential information in compliance with a protective order. (Issue 6)
   - The utility must provide to the public interim reports outlining its progress on development of the plan.

- The utility must provide a draft plan for public review and comment prior to filing a final plan with the Commission.

3. Plan filing, review and updates will follow this schedule:
    - The utility must file an integrated resource plan every two years. If the utility does not intend to take any significant resource action within two years, the utility may request a waiver.
    - The utility should present the results of its filed plan at a Commission public meeting prior to the deadline for written public comment.
    - Commission staff and parties should complete their comments and recommendations within six months of IRP filing.
    - The Commission will consider acknowledgment of the filed plan at a public meeting. If the Commission finds that further work on a plan is needed, it will provide comments to the utility. This process should eventually lead to acknowledgment of the plan.
    - The Commission will provide direction in its acknowledgment order for any additional analyses or other actions that the utility should undertake in the next planning cycle.
    - Each year the utility must submit an update for its most recently acknowledged plan. The update is due on or before the IRP filing anniversary date. The update is an informational filing that provides an assessment of what has changed since acknowledgment that affects the action plan including such conditions as loads, expiration of resource contracts, supply-side and demand-side resource acquisitions and resource costs. The update should explain any deviations from the acknowledged action plan such as actual conservation savings vs. targeted savings. The utility will summarize the update at a Commission public meeting.
      (Issues 1a and 7, 2b, c and d)

4. At a minimum, the plan should include the following elements:
    - An explanation of how the utility met each of the Commission's procedural requirements
    - An explanation of how the plan meets each of the Commission's substantive requirements
    - A 20-year load forecast with an explanation of major assumptions
    - For electric utilities:
        - Determination of the levels of peaking capacity and energy capability expected for each year of the plan given existing resources
        - Identification of capacity and energy needed to bridge the gap between expected loads and resources
        - Modeling of all existing transmission rights, as well as future transmission additions associated with the resource portfolios tested
    - For natural gas utilities:

  - Determination of the peaking, swing and base-load gas supply and associated transportation and storage expected for each year of the plan given existing resources
  - Identification of gas supplies (peak, swing and base-load), transportation and storage needed to bridge the gap between expected loads and resources
- Identification and estimated costs of all supply-side and demand-side resource options, taking into account anticipated advances in technology
- Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs
- Identification of key assumptions about the future — for example, fuel prices and environmental compliance costs — and alternative scenarios considered
- Construction of a representative set of resource portfolios to test various fuel types, technologies, lead times, in-service dates, durations and locations
- Evaluation pitting the portfolios against possible economic, environmental and social circumstances
- Results of testing and rank ordering of the portfolios by cost and risk metric and interpretation of those results
- Analysis of the uncertainties associated with each portfolio evaluated
- Selection of a portfolio that represents the best combination of cost and risk for the utility and ratepayers
- Identification and explanation of any inconsistencies of the selected portfolio with state and federal energy policies and any barriers to implementation
- An action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, regardless of whether the activity was acknowledged in a previous IRP

5. The utility should specify the key attributes of each resource evaluated and each resource included in the action plan, including operating characteristics, resource type, fuel and sources if applicable, technology, in-service date, duration and general location – system-wide or delivered to a specific portion of the system. (Issue 9)

6. ~~6.~~ Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered. In addition, utilities should consider fuel transportation and electric transmission system development as resource options. Such analysis should consider the value of such development for additional short-term purchases, additional sales, accessing less costly resources in remote locations, and acquiring alternative fuel supplies. Potential savings in distribution system costs should be identified in the plan for resources that can significantly reduce such costs, including conservation, demand response, combined heat and power facilities, customer standby

generation, solar resources, liquefied natural gas and gas storage. (Issue 11a)

Comment (related to Issue 11b – not included in Staff's proposal): Oregon is one of the few states that bases cost of service analysis on "long run incremental cost" studies. Normally, marginal cost refers to the first derivative of the total cost function with respect to a unit of output. In the case of utilities, like ours, the basic unit of output is a delivered therm. The short-run marginal cost of an additional therm (aside from the commodity cost itself) is nearly zero--as is the delivery cost of an additional kWh. Long run marginal cost is the cost of an additional unit of output when all inputs are variable--you build a new fully integrated energy utility. Obviously, we aren't interested in what it costs to build an entire new energy company. Hence, we use the term of art "long run incremental cost" -- not marginal cost. In the utility's case, the relevant incremental cost is the cost of serving another customer. This isn't quite marginal cost by the usual economic definition. It allows us to focus on the cost of adding an incremental customer (with a particular set of attributes) rather than the incremental therm.

The guideline for issue 11b is written as though there is a world of difference between MC and LRIC. The most important concept here is to reject the use of rolled in rates based on embedded historic costs in both IRP analysis and in inter-fuel cost comparisons.

7. Utilities must consider the availability of public purpose funds in assessing the optimal level of new renewable resources to acquire. They also must demonstrate how their action plan is affected by such funding and explain what steps they are taking to secure public purpose funds for planned renewable resources if there are above-market costs.

   All utilities should fully analyze conservation resources in portfolio modeling on par with supply-side resources, accounting for the cost and risk reduction benefits of conservation resources under all futures evaluated. Unless a third party funds and administers conservation programs, the utility should include in the action plan all least-cost/least-risk conservation resources for meeting projected load growth, specifying annual savings targets.

   A conservation potential study should be conducted periodically for each utility's entire service area. Along with any updates of energy usage trends and conservation costs, the study should form the basis for the 20-year conservation supply curves the utility uses in portfolio modeling.

   If the Energy Trust or other entity acquires conservation on behalf of the utility's Oregon customers, the utility should incorporate the entity's conservation projections in resource planning. Further, both should work cooperatively on the 20-year conservation assessments for the utility's

service area, as well as joint load management opportunities. Such assessments should incorporate the utility's load research data as well as its knowledge of energy usage trends by customer type.
(Issues 12 and 13)

8. Plans should evaluate demand response resources on par with other options for meeting energy, capacity, and transmission needs (for electric utilities) or gas supply and transportation needs (for natural gas utilities). Rate design should be treated as a potential demand response resource. The analysis of demand response resources also should account for potential distribution system savings in load growth areas. Utilities should develop supply curves for a wide variety of demand response resources spanning a wide range of costs. The utilities should use these supply curves to evaluate demand response in the risk modeling of portfolios. (Issue 14)

9. Utilities should include in their base-case analyses the regulatory compliance costs they expect for carbon dioxide (CO_2) emissions. Utilities also should analyze the range of potential CO_2 regulatory costs in Order No. 93-695, from zero to $40 (1990$). In addition, utilities should perform sensitivity analyses on a range of cost adders for nitrogen oxides, sulfur oxides and mercury, if applicable, including those based on market-based cap-and-trade programs as well as on projected changes in state and federal requirements or their implementation. Compliance cost projections should consider damages from pollution and estimates of mitigation costs. Sensitivity analyses are no longer required for total suspended particulates. (Issue 15)

10. ~~10.~~ The utility's load-resource balance should reflect customer loads to be served by an alternative electricity or natural gas supplier over the planning horizon. (Issue 17)

Comment: First, There is no distinction of interruptible versus firm industrial sales in this paragraph. Industrial interruptible transportation amounts to over 40 percent of our annual throughput. It implies that all industrial sales be treated the same as sales to residential/commercial customers, so some clarification is needed. After all, if we plan to serve all interruptible industrial sales (or interruptible transportation) requirements, why would anyone bother to pay for firm service? Second, these customers would have to request service by the utility just as new acquisitions do allowing the utility to seek charges equal to the cost of serving those customers.

11. Multi-state utilities should plan their generation and transmission systems, or gas supply and delivery, on an integrated system basis that achieves a least-cost/least-risk resource portfolio for all their retail customers. (Issue 8)

12. Potential ratemaking treatment should not affect the selection of the least-cost/least-risk portfolio. The utility should advise the Commission during the

planning process if it does not have reasonable incentives to acquire a resource that is part of that portfolio. (Issues 1d and 22)

13. To address reliability:
    - Electric utilities should analyze planning margin within the risk modeling of the actual portfolios being considered. The analysis should include varying loads, forced outages, hydro availability, and fuel and market prices and should allow for market purchases within transmission constraints. Loss of load probability and expected unserved energy should be evaluated by year and by future.
    - Natural gas utilities should analyze on an integrated basis gas supply, transportation, and storage, along with demand-side resources, to reliably meet peak, swing and base-load system requirements.
    - The plan should demonstrate that the utility's chosen portfolio achieves its stated reliability, cost and risk objectives.

    (Issue 21)

14. ~~14.~~Electric utilities should evaluate distributed generation technologies on par with other supply-side resources, including comparative costs for plant capital expenditures, transmission and environmental compliance. Electric utilities also should consider and where possible quantify the additional benefits of distributed generation, such as potential distribution system cost savings within load growth areas. (Issue 20)

Comment: It is not obvious what might be said about gas in this section, but no mention of gas seems to ignore that it is the principal fuel for combined heat and power. Of course, in order to solve electric distribution system bottleneck situations, sufficient gas distribution system capacity must be present.

15. The utility should identify in the action plan its acquisition strategy for each resource. Gas utilities should describe in the IRP their proposed bidding process for gas supply and transportation, whether formal or informal. Electric utilities should identify those resources that will be acquired through competitive bidding and indicate if they plan to have a utility resource considered in that process, whether utility-built or built by a third party and transferred to utility ownership. For ~~all~~ electric utilities, the competitive bidding process should follow IRP acknowledgment. Comment: Gas utilities do not use a formal competitive bidding process. Informal competitive bidding in the market place for commodity gas is under taken annually with each Purchased Gas Adjustment cycle and should not be tied to the IRP cycle. The cost and risk decision criteria for selecting resources in the bidding process should be consistent with the decision criteria for selecting resources in the acknowledged IRP. (Issues 1c and 16)

Comment: The Commission Staff appears to intend to move the analysis of gas supply portfolio risk into the IRP venue rather than address price volatility risk in the context of gas PGAs and electric PCAs. The case for analyzing electric price risk and power cost tradeoffs in the context of long-term electric planning is understandable. Electric utilities must evaluate portfolios with varying degrees of dependence on power markets and varying proportions of utility owned or purchased generation of various types. Electric price variability is addressed through long-term capital budgeting choices and to a much lesser extent through near term financial hedges.

The situation is different for natural gas. Gas utilities rely completely on gas markets. Gas utilities can't construct sources of gas -- except by purchasing reserves in place -- gas utilities can only diversify their gas purchasing arrangements. Wholesale price volatility is dealt with using hedging strategies, a diversity of supply sources in a variety of gas production regions and hubs, and a diversity of contract lengths (and gas storage when available). Gas LDCs may shield customers from the effects of price volatility through hedging, but the expected outcome is that gas utilities and their customers will simply pay market price for commodity gas when evaluated over a long period of time.

Gas supply portfolio analysis belongs in the materials supporting gas cost tracking adjustments. Evaluation of capital investment choices between various demand- and supply-side resources belongs in the Integrated Resource Planning process. Northwest Natural sees the IRP process as a capital stock optimization process not a near-term commodity gas portfolio optimization effort. Gas IRP properly focuses on the means of transporting and storing natural gas (or its alternatives) and ways of reducing the demand for natural gas. Reducing the demand for natural gas can take the form of capital stock changes that improve the efficiency of gas use, and a variety of methods for modifying the demand for gas through behavior changes.

Regardless of how we approach portfolio optimization in the PGA process, we will pay market price for commodity gas. The appropriate risk/cost tradeoff to be analyzed in the IRP process involves the risk (eventual cost) of not acquiring/encouraging cost-effective energy efficiency improvements because of underestimating the future cost of using natural gas.

NW Natural

CERTIFICATE OF SERVICE

I hereby certify that on the 30th day of September, 2005, I served the foregoing NORTHWEST NATURAL'S REPLY COMMENTS IN OPUC Docket No. UM 1056 upon each party listed below by emailing an electronic copy to all parties on the service list in this docket as of the above date.

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