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September 9, 2005

VIA FILING CENTER

Public Utility Commission of Oregon
550 Capitol Street, N.E., Suite 215
Post Office Box 2148
Salem, Oregon 97308-2148

ATTN: Filing Center

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

Opening Comments of NW Natural

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

Please contact me if you have any questions.

Sincerely,

/s/ Joe Ross

Joseph M. Ross
Rate Economist/Planning Analyst

kcm

enclosures

cc: UM 1056 Service List

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

In the Matter of	)	
	)	
PUBLIC UTILITY COMMISSION OF OREGON	)	UM 1056
	)	
	)	
In the Matter of an Investigation into Integrated Resource Planning Requirements	)	
	)	

OPENING COMMENTS OF
NORTHWEST NATURAL GAS COMPANY

Pursuant to the staff of the Public Utility Commission of Oregon (Staff) schedule modification dated July 11, 2005, Northwest Natural Gas Company (NW Natural) hereby files the following Opening Comments, embedded within Staff's Initial Responses, in this proceeding regarding integrated resource planning requirements.

I.

General Comments

In general, NW Natural's comments attempt to add clarifications that seem necessary when it is recognized that IRP results may be used in evaluating public policy toward end-use fuel choices and fuel switching. Insofar as interfuel comparisons of avoided cost estimates are one of the major focal points in such discussions, the absence of the phrase *avoided cost* in both this, and the "Straw Proposal" document is of concern.

II

Staff's Initial Responses
Integrated Resource Planning Requirements
Docket UM 1056

Following are staff's initial responses in this docket, organized by issue number according to staff's issues list submitted on April 21, 2005. The document is divided into two sections. Issues addressed in the first section relate to staff's draft proposed guidelines; the second section responds to other issues in the proceeding.

Issues Directly Related to Staff's Proposed Guidelines

Issue 1(c): *How should the Commission review utility implementation of integrated resource plans?*
Issue 16: *Should IRPs incorporate competitive bidding results, or should the Commission acknowledge the IRP before the utility conducts RFPs for resources identified in the action plan?*

> *Related guideline*: 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 electric ~~all~~ utilities, the competitive bidding process should follow IRP acknowledgment. Gas utilities do not use a formal competitive bidding process. Informal competive 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.
>
> 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.

An annual action plan update should advise the Commission of what has changed since acknowledgment that affects the action plan, including such conditions as loads, expiration of resource contracts, resource acquisitions and resource costs. The update also should explain any deviations from the acknowledged action plan. (See issue 2c.)

The electric competitive bidding process should be closely aligned with the IRP process and should follow IRP acknowledgment. If a utility needs to begin the Request for Proposal (RFP) process prior to IRP acknowledgment — because of unforeseen changes in resources or loads, for example — the Commission may consider such circumstances when it considers the RFP for approval.

Docket UM 1182 will determine the conditions under which the utilities will file RFPs for the Commission's approval. As part of the review process for RFP approval, the Commission should determine whether the RFP is consistent with the acknowledged IRP. If they are not consistent, the Commission should determine whether such deviations are reasonable given information at the time or any changes in conditions. The analytical methodologies employed in the acknowledged IRP should form the basis for the utility's evaluation of the actual resources it will acquire through the RFP process.

Ultimately, the Commission's review of IRP implementation will occur in a rate case where it makes its prudence determinations.

Issue 1(d): *How do the Commission's ratemaking policies and practices affect resource evaluation and selection? Should IRPs address whether changes to ratemaking policy could improve the outcome of resource planning?*
Issue 22: *Should utilities assume a specific ratemaking treatment when evaluating alternative resource addition, e.g., including only the intrinsic value of capacity contracts in rates, versus including the real option value (i.e., both the intrinsic and extrinsic value) of capacity contracts in rates?*

> *Related guideline:* 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.

If existing ratemaking policies and practices are unduly influencing resource evaluation and selection, the Commission should be made aware of these effects during the IRP process. For example, the utility should advise the Commission if it does not have an incentive to acquire combined heat and power facilities that are part of the least-cost/least-risk portfolio. The utility also should advise the Commission if it would not be able to pursue a particular resource that is part of the least-cost/least-risk portfolio under a particular ratemaking treatment — for example, if the utility would not pursue a capacity tolling contract under a ratemaking regime that included the real option value of that resource in retail rates. However, any proposed changes to ratemaking policy should be addressed outside of the IRP process.

Issue 2(a): *What should be the planning horizon?*
Issue 3: *How should integrated resource plans measure and consider the cost-stochastic risk tradeoff between candidate resource portfolios? How should the utilities evaluate and compare resource portfolios comprised of resources of different fuel types and technologies and different durations?*
Issue 4(a): *What principles and metrics should the utilities use to weigh other types of risks, e.g., the risks associated with owned resources vs. purchased resources?*
Issue 5: *Should the Commission modify, delete or add substantive requirements for integrated resource plans, e.g., should the Commission consider whether a resource plan is in the long-term public interest and whether the plan is consistent with the energy policy of the state or Oregon as expressed in ORS 469.010, as currently required in Order No. 89-507? How should the utility assess whether its integrated resource plan is in the long-term public interest and is consistent with the state's energy policy?*

> *Related guidelines:*
> The plan must meet four substantive requirements:
> 1. All resources 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.

2. 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 uncertainty, ~~(peak, swing and base-load)~~, 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.

3. 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 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.

4. The plan must demonstrate that it is consistent with the long-run public interest as expressed in state of Oregon and federal energy policies.

Substantive elements 1 and 2 should remain the same as in Order No. 89-507. Elements 3 and 4 should be modified slightly as indicated above to address both cost and *risk* and to accommodate any changes in state and federal policies. Further, the Commission should specify how to meet each substantive requirement. Staff has provided recommendations for doing so under the first three elements.

The Commission adopted a requirement that the utilities present a sensitivity analysis using a range of reasonable discount rates in Order No. 90-1658, its first acknowledgment order. The Commission affirmed that requirement in Order No. 91-1552. Performing sensitivity analyses on the discount rate addresses the uncertainty of the time value of money over the planning horizon and the effect on PVRR of *when* expenditures occur in the planning period. For example, a sensitivity analysis using a *low* discount rate will reflect a *higher* cost today for expenditures in the latter part of the planning period, compared to using a high discount rate.

In the latter order, the Commission also adopted a requirement that the utilities use the real after-tax marginal weighted-average cost of capital to discount all future resource costs. The Commission affirmed this requirement in Order No. 93-695. Utilities should use the weighted-average authorized cost of equity and preferred stock plus their marginal cost of debt.

Regarding elements 2 and 3, Order No. 89-507 states (at 2): "The result of the [resource planning] process is the selection of that mix of options which yields, for society over the long run, the best combination of expected costs and variance of costs. The variance reflects the risk of bad outcomes, such as energy shortage or substantial excess capacity."

The Northwest Planning and Conservation Council distinguishes between uncertainty and risk in its Fifth Power Plan (at 6-2 to 6-3):

> Uncertainty is a measurement of the quality of information about an event or outcome. Some future events are uncertain, but there is a significant amount of information about their likelihood. For example, the total annual flow at Bonneville Dam in 2010 is uncertain, but 61 years of

> historical records provide information about the distribution of outcomes. Other future events are less certain, like prices of natural gas and electricity. Theory and experience are information to some degree, but expectations can be confounded. For others, there is very little information to go on…. Future events therefore lie along a spectrum of varying degrees of uncertainty.
>
> Risk is a measure of bad outcomes associated with a given plan [controllable future actions]. If the primary outcome of a study is the net present value cost over a study period, a bad outcome arises when a plan results in high development or use costs under a specific future [a combination of sources of uncertainty specified over the study period]. Risk is a measurement of the bad outcomes from the distribution of *all* outcomes associated with the plan under *all* the futures.

Besides the uncertainties included in the guidelines above as minimum considerations, the utility should identify additional sources of uncertainty. Examples include availability and value of economic credits such as federal incentives for generation from cleaner coal or renewable resources, emissions costs and wind integration costs. The utility should screen plans for those with acceptable levels of each kind of risk.

In addressing uncertainty and risk, the utility should discuss potential changes in loads, technologies, prices and other conditions. For example, utilities should discuss the role of liquefied natural gas and its potential effects on resource costs over the planning horizon, including the need for new or enhanced transportation facilities or contracts. Utilities also should discuss the risks associated with owned versus purchased resources. Docket UM 1182 should address how risks of owned versus purchased resources should be evaluated in the RFP process.

Risk analysis requires explicit quantitative measures that capture the likelihood and severity of bad outcomes. As the Council points out (Fifth Power Plan at 6-3), "An unlikely outcome may still present significant risk if its effects are catastrophic." Risk measures also should capture the value of resource portfolio diversity and provide consistent results.

In assessing severity of bad outcomes, a given portfolio should not be deemed less risky than an alternate portfolio if each of the outcomes for the given portfolio are worse than those for the alternate portfolio.

Further, planning should incorporate the likely costs associated with failing to perfectly anticipate all costs, prices and requirements. The utility should model how the resource portfolios under consideration adapt to future circumstances, including the associated costs. Including such costs reveals plans that are robust — those that can be quickly and inexpensively modified. The utility should assign probability distributions to uncertainties to explicitly value resource options that reduce risk.

Regarding substantive element 4 and demonstrating that a plan is consistent with the long-run public interest, a utility should consider in its planning process all costs with a reasonable likelihood of being included in rates in the future. That includes costs related to meeting customers' energy needs that currently are not included in energy rates ("external costs"), but which have a reasonable likelihood of being included in rates in the future. Examples of past external costs that utility customers now face are mitigation costs for impairment of fish and wildlife habitat and mercury emissions. A range of potential mitigation costs and associated probabilities should be used in the resource evaluation.

External energy costs may be addressed in state or federal energy policies. Such policies, however, may simply state a preference for certain types of resources or indicate goals. For example, utilities should explain in their plans how they address Oregon's goals in ORS 469.010 regarding efficient use of energy and development of permanently sustainable energy resources. Over time, such preference policies may change to mandates – for example, a new emissions constraint or minimum acquisition levels for a particular type of resource, such as a Renewable Portfolio Standard. Resource planning should take this into account, and the utility should explain how the action plan addresses such regulatory risks.

Further, utilities should explain how their proposed resource actions balance various government policies – for example, ORS 469.010 vs. providing adequate service at just and reasonable rates (ORS 757.020). Electric utilities also should explain how their plans are consistent with provisions related to electric industry restructuring, including ORS 757.601 to 757.612.

Issue 2(b): *How often should integrated resource plans be filed?*

> *Related guideline*: 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.

(c) *How often should utilities update action plans?*

> *Related guideline*: 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.

(d) *What is the appropriate time period for completing the integrated resource planning process?*

Related guidelines:
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.

Issue 6: *What data should be treated confidentially in integrated resource planning?*

Proposed guideline: 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.

The Commission's resource planning process relies heavily on public input. Therefore, the utilities should provide publicly as much data as is practicable. For example, if the utility has current bids for renewable resources and is in negotiation with bidders, the utility could provide in the IRP the bid cost information in aggregate so that specific bids cannot be identified. *See* PacifiCorp 2004 IRP Technical Appendix, Figure J.1, p. 145.

Issue 8: *For multi-states utilities: Should integrated resource planning be conducted to optimize Oregon or system costs? How should integrated resource planning reconcile different planning rules or standards in different jurisdictions? How should integrated resource plans address different state or regional resource preferences?*

Related guideline: 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.

To the extent that another state's requirements differ from the above guideline — for example, a state that requires the multi-state utility to optimize costs for its customers in that state — these requirements should not impair the plan that is filed in Oregon that reflects least-cost/least-risk to all the utility's retail customers, not only those in a particular state.

Multi-state utilities should identify in their integrated resource plans any analyses or proposed resource activities that respond to unique state or regional requirements and preferences and describe how they lead to results that are consistent or inconsistent with Oregon's direction.

Issue 9: *Should the Commission acknowledge generic or specific resource actions? For example, should the Commission acknowledge a generating plant of a certain design and at a specific utility-owned location?*

> *Related guideline:* 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.

Generally, the Commission should acknowledge generic resources, rather than specific facilities at designated sites (for example, Port Westward or Hunter 4). At the same time, the resources evaluated and included in the action plan should be described in sufficient detail so that the Commission understands what it is being asked to acknowledge.

Examples of some of the attributes that should be specified include the following:

- Operating characteristics – Base-load vs. peaking
- Resource type – Conservation; demand response resources such as direct load control, demand buyback, interruptible contracts and other rate options; renewable resources; coal resources; natural-gas fired resources; combined heat and power resources; new transmission lines and short-term market resources
- Fuel and sources – Liquefied natural gas from a specified terminal, Powder River Basin coal
- Technology – Supercritical pulverized coal vs. Integrated Gasification Combined Cycle coal, single-cycle vs. combined-cycle gas turbine

If the action plan includes a specific resource that the utility does not plan to acquire through the competitive bidding process, the utility should explain whether there are no viable alternatives or there are other reasons for the proposed acquisition.

Issue 11(a): *How should transmission and distribution investments/costs and opportunities be incorporated into integrated resource planning?*

> *Related guideline:* 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.

Fuel transportation and transmission system investments that are required for any resource being considered should be included in the PVRR analysis. In addition, the value of such investments should be distinguishable from other resource actions. For example, the value of a new transmission line includes risk mitigation for load fluctuations, hydro variation, unplanned outages, and fuel and market price volatility, as well as meeting planning reserve margin at least cost.

The integrated resource planning process should not be the primary vehicle for planning distribution system investments. However, the Commission should require the utilities to identify in the IRP opportunities for distribution system cost savings for resources that have the potential to significantly reduce such costs.

Further, the Commission should develop guidelines for electric utilities for evaluating during their distribution and transmission system planning processes whether distributed generation, targeted energy efficiency and demand response can cost-effectively and reliably defer or avoid certain types of distribution and transmission system investments and, where appropriate, obtain the lesser-cost alternative. Today, utility planning for distribution and transmission does not systematically assess these potential cost savings.

The Bonneville Power Administration, for example, has incorporated into its planning process for all capital transmission projects over $2 million a screening process for such non-wires solutions. Bonneville also is funding pilot programs to resolve institutional barriers, test technologies and build confidence in using them.

Staff plans to ask the Commission at a later date to open a proceeding for electric utilities to require economic non-wires solutions to be considered in distribution and transmission system planning. The Commission should develop screening guidelines for determining whether a planned grid investment is a candidate for non-wires alternatives, guidelines for analyzing alternatives for cost-effectiveness, reliability and other requirements, and reporting requirements. The Commission also should explore pilot programs with the utilities and stakeholders such as the Energy Trust of Oregon to test approaches for acquiring non-wires solutions.

Issue 13: *How should cost-effective conservation be analyzed and included in resource planning? Should a conservation potential study be conducted and, if so, how?*

Related guideline: 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. Utilities 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.

Planning for demand-side management remains an integral part of the resource planning process for all utilities in determining the least-cost/least-risk portfolio. Therefore, all utilities are responsible for assessing conservation potential. Where a statutory requirement mandates certain conservation provisions, such as program funding and third-party administration, the utility should work cooperatively with that party on studies of conservation potential.

Unresolved from Docket UM 1169, now suspended, is whether ORS 757.612 allows spending more on energy efficiency than provided by the public purpose charge. Also at issue is whether Portland General Electric (PGE) and PacifiCorp could recover in rates the cost of a conservation study for their Oregon service area. The answer depends in part on whether the Commission deems the study an essential part of the integrated resource planning process, part of the Energy Trust's role in administering public purpose funds, or a combination of the two.

ORS 757.617(1)(b) requires that the Commission and the Oregon Department of Energy contract for a report to the Legislature describing proposed modifications to ORS 757.612. While the statute requires the report by Jan. 1, 2007, the Commission intends to provide the report to the Legislature well in advance of that date. A conservation potential study for PGE and PacifiCorp should inform any proposed modifications to the public purpose charge.

The Energy Trust recently issued a solicitation for a study of technical and achievable conservation potential through 2017 for the Oregon service areas of PGE, PacifiCorp and NW Natural. The utilities should be part of an advisory group directing the study and make available under confidentiality agreements load research data, data on energy usage trends, and other useful information for assessing conservation potential.

Staff agrees with comments by the Citizens' Utility Board in its request to suspend Docket UM 1169: "At the very least, we ought to first update the conservation supply estimates developed prior to the roll out of the Energy Trust programs to reflect lessons learned from the Energy Trust and NW Energy Alliance programmatic experience." *See* CUB's Motion to Suspend Proceeding at 2. Staff further agrees that "such a study will identify whether the legal question of whether 757.612 allows for energy efficiency expenditure beyond current levels is relevant or ripe." *Ibid* at 3.

Issue 14: *How should demand response be explicitly included in integrated resource planning on par with other options for meeting energy and capacity needs?*

> *Related guideline:* 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.

In Order No. 03-408, the Commission directed that the utilities' Integrated Resource Plans should evaluate demand response programs on par with other options for meeting energy and capacity needs. The Commission further ordered that Docket UM 1056 determine how to do so.

Demand response resources may meet a portion of utility obligations at lower cost — and risk — than supply-side resources. Utilities should account for the reduction in PVRR and PVRR risk in portfolio modeling and consider other benefits of demand response resources. For example, demand response resources can be put in place more quickly and therefore have lower risks for overbuilding than supply-side resources with long lead times. Demand response resources also may provide the utility with flexibility for reliably serving load while allowing the utility to take advantage of new supply-side technologies on the horizon, or having more certainty of emerging costs for regulatory compliance that may affect the optimal resource mix.

If the utility does not fully assess demand response resources in its IRP and include in the action plan those that are part of the least-cost/least-risk portfolio, then it will acquire more supply-side resources than is optimal.

The utilities can use RFP results as well as in-house analyses to develop supply curves for a wide variety of demand response resources, including various types of direct load control, interruptible contracts, demand buyback and other rate options, spanning a wide range of costs. Periodically, the utility should conduct an economic analysis of achievable demand response resources in its service area over the IRP study period and explain in the IRP how demand response resources included in the action plan compare with the economic amounts determined in the study.

The utility should not place firm constraints on the amount of demand response resources modeled and test them only in the preferred portfolio, but instead test various amounts and types within modeling of all portfolios as resources that compete with generating resources. Only portfolio risk modeling can accurately advise the utility of the cost and risk benefits of such programs for critical peak and other hours of the year, relative to other resource options. The full planning value of certain types of demand response resources — demand buyback, for example — may not be revealed without modeling market price excursions.

The Commission should maintain its guideline from Order No. 89-507 (at 10) that "…rate design should be treated as a potential demand-side resource." Long-term pricing programs at utilities in the U.S. and abroad show persistent load reductions during peak periods and help avoid the need for new power plants. One such program is Georgia Power's two-part real-time pricing program for large customers. California's recent time-varying pricing programs for small customers, as well as voluntary time-of-use pricing for Oregon residential and small business customers, show promising reductions in peak loads for the mass market.

Issue 15: *Should the Commission update the type of CO_2 risk analysis required by Order No. 93-695, including the cost adder values? Should the Commission update other types of environmental adders required for risk analysis?* [The second part of this issue was added at parties' request; Judge Logan does not object.] *Should utilities be required to assign an imputed cost for CO_2 in IRPs?*

> *Related guideline:* 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.

The range of potential CO_2 regulatory costs specified in Order No. 93-695 — zero, $10, $25 and $40 (1990$) — remains appropriate for risk analysis at this time. However, the Commission should update the values to current dollars. For example, Idaho Power's most recent IRP updated these values to 2004 dollars, and PacifiCorp's 2004 IRP converted these values to 2010 dollars.

The cost of complying with total suspended particulate standards is dwarfed by compliance costs for other pollutants, including mercury, which is now coming under regulation. Therefore, sensitivity analyses for particulates should no longer be required.

The range of potential long-term compliance costs that the utility evaluates in the IRP should take into account estimates of actual mitigation costs for damages from pollution. Such estimates indicate the maximum extent of costs that could be included in rates in the future.

Utilities should include in their base-case analyses the regulatory compliance costs they expect for CO_2 emissions in the future. The sensitivity analyses required by Order No. 93-695 as updated in this proceeding will continue to provide the Commission with information to indicate how portfolios may perform under potential CO_2 regulatory scenarios.

If the Commission decides to assign an imputed cost for CO_2 for integrated resource planning, the Commission cannot require the utilities to choose resources on that basis. Utility management will retain full responsibility for making decisions and for accepting the consequences of the decisions. However, the Commission can take any assigned imputed cost, as well as required CO_2 sensitivity analyses, into consideration in subsequent resource acquisition and ratemaking proceedings.

Issue 17: *How should customers eligible to choose an alternative electricity or natural gas supplier be accounted for in integrated resource planning?*

> *Related guideline:* 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.

Staff believes that PacifiCorp should continue at this time to plan to serve the entire forecasted load in its Oregon service territory on a long-term basis given the level of participation in direct access to date and customers' ability to return to cost of service rates each year. This issue should be revisited if direct access participation increases significantly, if the company adopts and has sizable participation in a tariff similar to PGE's five-year opt-out program, or if customers participate in a permanent opt-out tariff as envisioned in Order No. 05-133.

For PGE, staff agreed with the approach in the company's most recently acknowledged plan. Instead of removing from the load forecast the requirements of most direct access customers, PGE's long-term planning includes short-term energy supply to meet the average annual energy need for both index rate (standard offer) and direct access customers other than those participating in a long-term opt-out program. Some 11% of eligible PGE customers selected an alternative electricity supplier for service in 2005, and the company has ongoing multi-year opt-out programs.

Gas utilities should continue to plan for full service for all residential and commercial loads, along with sales service for industrial load. For industrial customers that have bypassed the gas utility or are only receiving transportation service from the gas utility, planning should focus on the resources needed if all or a portion of these customers returned to sales service. Comment: 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?

Issue 20: *How should distributed generation be addressed in integrated resource planning?*

> *Related guideline:* 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.

Distributed generation produces electricity at or near the place where it's used. Technologies include high-efficiency combined heat and power resources that run on fossil fuel, biomass or waste heat; systems that use renewable energy resources to generate electricity without making use of any waste heat, such as solar electric systems, wind turbines, small hydroelectric generators, and turbines or engines using landfill gas; and dispatchable standby generation at customer sites, typically diesel.

In addition to evaluating transmission, capital expenditures and environmental compliance costs on par with other supply-side resources, distributed generation requires special consideration with respect to:

- Potential distribution system cost savings, particularly within load growth areas
- Reliability benefits from increasing the number of generating units on the system
- Facilitating participation in demand response programs by providing customers with backup power
- Matching gradual increases in utility loads with typically smaller project sizes as well as matching a customer's demand on the utility system with generation sized to that load
- Enabling customers to provide backup power for critical loads and supply premium power to sensitive loads, which could reduce the cost of unserved energy
- Increasing competition of power supply and reducing market power, particularly in transmission-constrained areas
- Reducing the need for *utility* investments in energy and capacity resources

The IRP should explicitly address each of these factors**.** For example, potential distribution cost savings may be determined based on an estimate of achievable distributed resources over the planning horizon within a load growth area. The analysis could be on a substation basis, or on the basis of deferring an upgrade or addition for another type of distribution facility.

Without considering these potential savings, much of the benefit of distributed generation resources to the utility system is left unanalyzed. The fact that IRP and distribution planning at the utility are separately performed functions does not justify incomplete analysis of all known resources. Consideration of avoided distribution system costs — a key benefit of well-located, reliable distributed generation resources — would provide a more accurate accounting of their potential value.

The Energy Trust of Oregon offers incentives for distributed renewable resources as well as high-efficiency combined heat and power that qualifies as conservation. Utilities should coordinate their assessment and acquisition of distributed resources where Energy Trust incentives may be available.

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.

Issue 21: *How should the resource planning margin be determined to ensure resource adequacy and consider cost?*

> *Related guideline:*
> 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.

Regarding reliability for electric utilities, *loss of load probability* (LOLP) expresses the frequency of reliability disturbances, but not the magnitude of the outages. LOLP is the sum of each day's probability where demand is expected to exceed supply at the daily peak hour, over one year. LOLP typically is expressed in number of days over a period of several years – for example, one day in 10 years. *Unserved energy* indicates the magnitude of possible outages — the amount of obligation not served over a period of time. *Expected unserved energy* is the *average* unserved energy over all model runs when the simulated system is stressed stochastically.

Providing the metrics by year and by future provides the Commission with the detail it needs to evaluate risks not captured by net present value costs or summary reliability statistics. Such risks include, for example, annual cost impacts or severe reliability problems in particular futures.

Ultimately, these metrics are *economic* choices. Therefore, the Commission needs to understand the tradeoff between higher reliability and higher cost. Planning margin is the *consequence* of resource decisions necessary to provide an acceptable level of risk at least cost. It should not be an input to that selection.

The choice of resources, including the size and reliability of each technology, affects the reliability of the system. Utility system size, average generating unit size and outage rate, resource mix, modeling approach and modeling assumptions can cause differences in the optimal planning margin level.

Where a reliability organization does not have access to detailed economic information, it uses deemed LOLP and reserve margins as rules of thumb. Where a utility has detailed economic information, however, it is far preferable to use that information to analyze the planning margin metrics using the actual resources in the utility's system, including those being contemplated as additions.

The optimal level for reliability metrics is a function of the resource makeup of the system. Therefore, planning margin analysis should be conducted on the actual portfolios the utility is testing, not as a sideboard analysis using simplified assumptions. For example, a utility should not model the addition of just one type of generating plant when the actual portfolios under consideration are composed of a variety of resources.

All resources should be considered for meeting reliability objectives, including all types of demand response resources. Such resources are particularly important where there is a sizable amount of load the utility expects to serve for a small percentage of hours in a year. Demand response resources may lower the cost of reducing risk, as measured by LOLP or other metric.

Because the Commission may have a different view than the utility of which resource portfolio, and which planning margin, is best for ratepayers, at a minimum all top-performing portfolios should be evaluated for the optimal planning margin level. The utility should explain how it balanced cost and reliability in selecting its planning margin.

The Commission should state in its acknowledgment order whether it finds the utility's planning margin to be appropriate. Unless and until regional requirements are set, the Commission should direct incremental improvements for planning margin analysis for the next planning cycle in IRP acknowledgment orders.

Other Issues

Issue 1(a): *How can the Commission ensure that its integrated resource planning requirements are flexible enough to accommodate the unique and changing circumstances of the utilities under its jurisdiction?*
Issue 7: *Should the integrated resource planning procedures and requirements established in this docket be implemented as an Oregon Administrative Rule?*

IRP guidelines should be sufficiently broad to remain relevant over time and be adaptable to changing circumstances. At the same time, the guidelines must provide sufficient direction to the utilities, staff and parties on procedural, substantive and analytical requirements and other provisions.

The Commission should provide direction to the utility in the acknowledgment order for each IRP if additional analyses or other actions are required for the next planning cycle. Such direction is a necessary and important feature of acknowledgment orders. Otherwise, the Commission's IRP guidelines would have to be far more prescriptive and would require frequent updating.

Having the Commission's policies on integrated resource planning in Commission orders has worked well in the past and continuing to do so is preferable to adopting those policies as administrative rules. Maintaining IRP guidelines in Commission orders allows the Commission to update and refine the guidelines through subsequent orders. Further, Commission orders have the same force of law as administrative rules and are more easily adapted as may be necessary in the future.

If the Commission instead decides to provide its guidelines in administrative rules, it could include a waiver provision to allow the utility to request a departure from a particular requirement.

(b) *Given the changes in the utility industry, what are the purposes and objectives of integrated resource planning?*

The purposes and objectives of integrated resource planning remain largely the same as in 1989 when the Commission first established its least-cost planning (LCP) guidelines:

> The goal of utility planning is to assure an adequate and reliable supply of energy at the least cost to the utility and its customers consistent with the long-run public interest….
>
> It requires integration of supply and demand side options. It requires consideration of other than internal costs to the utility in determining what is "least-cost." And it involves the Commission, the customers and the public prior to the making of resource decisions rather than after the fact….

> [A]lthough a decision made in the LCP process does not guarantee favorable rate-making treatment, the process should provide some guidance to a utility. The diversity of opinion presented during the process and the biennial updating of reports should reduce the likelihood of inaccurate estimations of new resource requirements. The openness of the process and participation in it by the public and the Commission should reduce the uncertainty regarding the rate-making treatment of a utility's acquisition of new resources." *See* Order No. 89-507 at 2-3.

However, the 1989 order was silent on transmission, which is increasingly important in providing reliable service, taking advantage of short-term and low-cost market resources, providing access to a diverse set of resources, and mitigating risk. The transmission siting process, including lead time, also has changed substantially. Therefore, planning for transmission resources associated with energy and capacity needs should be firmly established as part of the IRP process.

In addition, wholesale energy markets have changed as a result of federal policies and actions by states in the Western interconnection. These changes increase the importance of addressing the appropriate level of market purchases and sales in reducing costs and risks, as well as transmission alternatives that can meet resource needs through short-term transactions.

Funding and administration of conservation, as well its planning and evaluation, also have changed for PacifiCorp and PGE since 1989 as a result of Oregon's electric industry restructuring law. Their recent IRPs used Energy Trust projections for conservation in Oregon, rather than the historical practice of evaluating themselves the appropriate level of conservation resources for their Oregon service area.

High and volatile natural gas prices, increasingly stringent pollution controls, concerns about CO_2 emissions and climate change, and technological advances for renewable resources, fossil-fuel plants, and meter and communication technologies that enable demand response are now important considerations in assessing the costs and risks of supply-side and demand-side resources. The 2000-01 energy crisis illustrated the importance of planning for and acquiring demand response resources.

Demand response, conservation targeted to peak load reductions, and distributed generation are now being established as cost effective and reliable non-wires solutions for meeting targeted transmission and distribution system needs. Their actual value to the utility system may not be revealed without an examination of their potential cost savings for generation, transmission and distribution investments as well as their risk reduction benefits.

Issue 3(b): *What assumptions should the utilities make about the sharing or allocation of stochastic risk between shareholders and ratepayers?*

Utilities should state in the IRP their assumptions about the sharing or allocation of stochastic risk between shareholders and ratepayers. If the utility has a power cost adjustment or other automatic adjustment mechanism in place, the utility should discuss how it affects their proposed resource actions.

Issue 4(b): *Should integrated resource plans discuss global warming and its potential impacts on utility customers?*

Integrated resource plans should discuss global warming and its potential impacts on utility customers. The discussion should be focused on the effect of potential compliance costs on future rates over the long term, which extends beyond the planning horizon and the life of the resource.

Issue 10: *What is the significance of Commission acknowledgment of a resource action in a prudence hearing or rate case regarding an investment or purchase? For example, what type of prudence challenge will the Commission consider if the utility acquires a specific resource or a targeted level of resources of a certain type, consistent with the acknowledged action plan?*

The significance of Commission acknowledgment should remain unchanged. Commission acknowledgement of a resource action in an IRP is a finding, based on the utility's IRP analysis, that the proposed action appears reasonable at that point in time. Commission acknowledgment provides some assurance that if the future unfolds as projected, the utility's actions will continue to be considered reasonable in a future prudence hearing or rate case. If the future does not unfold as projected, the Commission will consider in a prudence review how the utility modified its resource actions.

Issue 11b: *Should incremental gas transportation and electric transmission capacity needs be modeled at both rolled-in embedded cost and incremental cost, allowing for the comparison of both cost options in the IRP?*

Neither rolled-in nor incremental cost should be the focus for modeling gas transportation and electric transmission capacity needs. Rather, modeling should focus on marginal cost – the cost of providing the next unit of service (megawatt or Dekatherm, for example). This helps ensure that all resources, current and proposed, are treated comparably.

Comment: 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

Issue 12: *How does the Oregon Energy Trust's responsibility for conservation and renewable resources affect the integrated resource planning process for Portland General Electric, PacifiCorp and NW Natural?*

ORS 757.612 established a public purpose charge on electricity bills primarily for conservation and the above-market costs of new renewable resources. The charge applies to utilities subject to direct access requirements, including PGE and PacifiCorp, through February 2012. NW Natural voluntarily adopted a public purpose charge for conservation.

The Energy Trust of Oregon administers the public purpose funds, with oversight by the Commission. The utilities have applied the Energy Trust's year-by-year conservation projections as decrements to their load forecast.

PGE and PacifiCorp continue to plan for new renewable resources, and the Energy Trust may cover any above-market costs. The utilities must negotiate funding on a project-by-project basis, or may require the project developer to directly negotiate with the Trust. The utilities are working on agreements with the Energy Trust to facilitate that process.

Issue 18: *Should integrated resource plans evaluate the impact of resource decisions on retail rates?*

Because retail rates are based on the cost of service, arguably IRP implicitly evaluates the impact of resource decisions on retail rates. That is why the goal is to choose the least-cost/least-risk portfolio. Explicitly evaluating the impact of resource decisions on retail rates may be useful to put into context the effect of a large proposed investment as well as alternatives that may pose less risk, but appear more costly under today's assumptions.

In addition to analysis that focuses on expected costs and severity of potential bad outcomes, utilities should develop risk metrics that measure variability in annual revenue requirements for resource portfolios. Comment: Is it the intent of this guideline to ignore the effects of retail prices and weather on use per customer?

Issue 19: *For expiring contracts, should integrated resource planning assume expiration or renegotiation or some combination of the two options?*

All utilities should assume contracts with interruptible customers continue unless such resources will not be available or other resources would provide better value. Electric companies also should assume existing contracts with Qualifying Facilities continue.

Treatment of expiring supply-side contracts should be determined on a case-by-case basis, including estimated costs and risks of the resource under a renegotiated contract versus other resource options.

Issue 23: *How should the requirement in OAR § 860-038-0080(1)(b) that new resources be reflected in rates at market rates impact the integrated resource planning process?*
Issue 24: *How should a utility's request to waive the market price rule for new resources impact the integrated resource planning process?*

The Commission's docket addressing whether new generating resources should continue to be included in an electric utility's revenue requirement at market price or at cost (UM 1066) is in abeyance, pending the conclusion of ongoing investigations into IRP and competitive bidding and a future investigation into performance-based ratemaking. The Commission directed in Order No. 05-133 that in the interim, if a utility wants to include a new generating resource in its revenue requirement at cost, the utility must file a request to waive the administrative rule.

In LC 33, the Commission addressed PGE's request to include Port Westward in its revenue requirement at cost *separately* from its consideration of the company's IRP. The Commission also indicated that utilities should request acknowledgment in the IRP process for generic, rather than specific, resources. Further, utilities subject to direct access requirements must continue to offer a cost of service rate for all customers until the Commission determines that certain market conditions are met. *See* ORS 757.603. Considering all these factors together, staff does not believe that the market price rule has a significant impact at this time on the IRP process.

Issue 25: *How should integrated resource planning be integrated with SB 1149 requirements? How do the following SB 1149 implementation issues affect current resource plan requirements: availability of a cost of service rate for different customer classes, the resource plan requirement (OAR 860-038-0080) and long-term supplies for standard offer service? How should an option for large customers to opt out of PGE's and PacifiCorp's new generation resources be accounted for in integrated resource planning?*

ORS 757.601 requires PGE and PacifiCorp to offer a portfolio of renewable resource and market-based options for all residential and small business customers, as well as direct access to alternative electricity suppliers for all nonresidential customers.

At this time, all customers participating in portfolio options rely on the same energy resources that supply the cost of service rate. The utilities purchase Tradable Renewable Credits to match renewable resource purchases. Therefore, the utilities should continue to plan to serve portfolio customer loads in the same manner as cost of service loads.

Reductions in peak load and energy consumption resulting from market-based portfolio rates should be accounted for in the utility's load-resource balance.

ORS 757.603 requires that PGE and PacifiCorp continue to offer a "regulated, cost of service rate option" until the Commission finds "... that a market exists in which retail electricity consumers ... are able to:

(A) Purchase supplies of electricity adequate to meet the needs of the retail electricity consumers;
(B) Obtain multiple offers for electricity supplies within a reasonable period of time;
(C) Obtain reliable supplies of electricity; and
(D) Purchase electricity at prices that are not unduly volatile and that are just and reasonable."

The utility's load-resource balance should reflect customer loads to be served by an alternative electricity supplier over the planning horizon. The utility should consider, for example, current direct access and standard offer loads and the types of commitments customers are making to opt out of a cost of service rate.

Because PGE and PacifiCorp must continue to offer all customers a cost of service rate, they use *annual* valuation rather than *one-time* valuation as envisioned in an OAR 860-038-0080 resource plan. Until and unless the cost of service provision is waived for any customer class, the resource plan requirement will not affect the IRP process. OAR 860-038-0080(1)(a) provides in part, "At such time as the Resource Plan is implemented and fully executed, each electric company will retain in its Oregon revenue requirement costs associated with a level of generating resources that is not greater than that necessary to meet the current and reasonably expected future loads of its Oregon cost-of-service consumers."

Regarding long-term supplies for standard offer service, if a utility forecasts sizable participation in its market-based options, it can match that load with targeted index purchases.

Issue 26: *What is the relationship between an integrated resource plan and a resource rate plan under ORS 757.212?*

The relationship between the IRP and an ORS 757.212 resource rate plan is little different than the relationship between the IRP and a rate filing under ORS 757.205. The Commission's ruling in an IRP may inform its decision as to whether to approve a resource rate plan filed under ORS 757.212. However, decisions on whether and at what amount to include the costs of a resource in a utility's revenue requirement will not be made in the IRP process.

III

Staff's Straw Proposal
Integrated Resource Planning Guidelines for Energy Utilities[1] (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 demand (peak, swing and base-load), 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 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.
- To address risk, the utility should at a minimum:

[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.

    - 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 that the utility should conduct 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. (Issue 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. 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 their value 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, combined heat and power facilities, customer standby generation, solar resources, liquefied natural gas and gas storage. (Issue 11a)

7. 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. Utilities 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. (Issue 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. 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)

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 objectives at least cost/least risk. (Issue 21)

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)

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 electric utilities~~all utilities~~, the competitive bidding process should follow IRP acknowledgment. Gas utilities do not use a formal competitive bidding process. Informal competive 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)

CERTIFICATE OF SERVICE

I hereby certify that on the 9th day of September, 2005, I served the foregoing NORTHWEST NATURAL'S OPENING 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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