BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1056

In the Matter of an Investigation Into Integrated Resource Planning Requirements.	STAFF'S REPLY COMMENTS

The first part of this document addresses parties' comments related to staff's proposed guidelines for integrated resource planning, included with our opening comments. **We refer in each subsection below to the related guideline(s) in that *original* staff filing.** The second part addresses comments unrelated to staff's proposal.

Attached are staff's final proposed requirements and guidelines with revisions in response to parties' comments. We provide this proposal in markup format for easy identification of our changes. Staff also clarifies where we recommend that a provision be mandatory — what a utility "must" do to comply with the Commission's order — versus what a utility "should" do to demonstrate compliance.

COMMENTS RELATED TO STAFF'S PROPOSED REQUIREMENTS AND GUIDELINES

Staff's Approach

Portland General Electric (PGE) and PacifiCorp opine that staff's proposal is too prescriptive. Staff disagrees with this assessment.

Instead of setting minimum requirements and guidelines for resource planning, PGE recommends that the four substantive elements be "objectives," and any detail about how a utility meets these objectives, as well as what elements should be in a resource plan, be planning "conventions." PGE states that the utility should follow these conventions only if necessary to meet the objectives, and "should do things other than those listed as conventions if necessary to achieve the objectives." *PGE's Opening Comments at 9.*

PacifiCorp supports PGE's approach regarding planning conventions, "compliance with which is aspirational if appropriate." *PacifiCorp's Opening Comments at 7.*

First, as noted in staff's opening comments, many of staff's proposed guidelines that the utilities characterize as new or additional already have been adopted by the Commission in orders following its original planning order (Order No. 89-507). For example, Order Nos. 90-1658 and 91-1552 set out requirements for discount rate assumptions and sensitivity analyses. Other guidelines staff proposes simply incorporate the Commission's position as stated in Order No. 89-507 – for example, that all known resources should be considered, or that the planning horizon should be at least 20 years and account for end effects.

Second, based on staff's 15 years of experience in reviewing electric and natural gas resource plans, we find it necessary for the Commission to set forth minimum requirements for analysis to enable a determination of whether the plan seems reasonable and should be acknowledged. Unlike the resource planning process in some other states served by our energy utilities, acknowledgment means something in Oregon in a ratemaking proceeding.

We are not swayed by PacifiCorp's concern that in specifying minimum analytical requirements the Commission "may find itself much more enmeshed in technical details around planning analytics and requirements." *PacifiCorp's Opening Comments at 3.* Staff points out the brevity of its list of proposed requirements and guidelines underlying the heart of the IRP process – the substantive and procedural requirements, the elements of the plan, and achieving reliability, cost and risk objectives. IRP is the foundation of a utility's path to acquire resources that meet energy needs at the lowest possible cost and risk.

Specifically, staff does not understand why the utilities should be opposed, for example, to a requirement to consider all known resources, to use consistent assumptions and methods for evaluating resources, to measure risk using metrics that look at the severity of bad outcomes and the variability of costs, or to address the key uncertainties in today's energy market – demand, energy supplies and market prices. We also do not understand why the utilities should be leery of minimum required elements of an integrated resource plan so that the Commission has what it needs to consider acknowledgment.

Following are staff's responses to disagreements about our specific proposals as well as modifications proposed by parties.

Substantive Requirements (Proposed Guideline 1)

First substantive requirement.
<u>Commercialization status</u>. Staff agrees with PGE that it is important to consider the commercialization status of resources. However, it also is important to consider resources that are just beginning to be commercialized – for example, Integrated Gasification Combined Cycle (IGCC) coal plants — and resources that are expected to become commercially available during the planning horizon. If the Commission chooses to adopt a position on commercialization to clarify the

first substantive requirement, we recommend it do so in supporting text in the order, rather than in the requirement itself or a supporting guideline.

<u>Energy efficiency/demand response</u>. PGE recommends another addition to the first substantive requirement: “A set of actions that result in lower use of energy (such as energy efficiency measures and demand response) is a resource to the same extent as a set of actions that result in additional energy.” Staff agrees with this statement, with one exception: Demand response may not result in lower use of energy, but simply shift some energy use to off-peak hours or even increase energy use overall because of increased use during low-cost periods. Again, staff recommends that any such addition be included in supporting text in the order, rather than in the requirement itself or a supporting guideline.

<u>Resource duration</u>. PacifiCorp objects to staff’s proposal that utilities should compare resource durations in the IRP. The company states that the competitive bidding process is the appropriate venue for that comparison. Staff agrees that resource duration is an important component in the company’s evaluation of bids in its resource acquisition process. However, staff disagrees with PacifiCorp’s proposal to exclude this analysis in IRP.

We note that the “proxy” resources the electric utilities use for their IRP analyses all have an assumed duration. For example, PacifiCorp’s 2004 IRP assumed a 40-year life for coal plants, a 35-year life for natural gas-fired combined cycle combustion turbines (CCCTs) and 20-year wind power contracts. *See Table C.27, PacifiCorp 2004 IRP Technical Appendix, pp. 65-66.* The assumed duration of resources modeled in an IRP affects the cost and risk values for the portfolios, and year-by-year incremental energy and capacity needs throughout the planning horizon.

Further, the electric utilities clearly consider resource term in their IRPs when they evaluate the value of short-term market purchases. For example, based on PacifiCorp’s historical market purchases and its view of forward prices, all portfolios tested for its 2004 IRP included 1,200 MW of shaped capacity purchases on a rolling annual basis. These generally are purchases for one to three years, shaped to seasonal needs. The company also performed a stress test on its preferred portfolio, replacing these market purchases with CCCTs in FY 2009 and FY 2013. The company concluded that these short-term market transactions were significantly more cost-effective than building or buying long-term assets.

Similarly, PGE’s most recently acknowledged action plan includes 125 MWa of short-term energy supply to meet its average annual energy need for customers on indexed rates or short-term arrangements with an electricity service supplier.

<u>Discount rate</u>. PacifiCorp states that staff’s proposal to use the “real after-tax marginal weighted-average cost of capital” (WACC) to discount all future

resource costs is “mathematically incorrect” and is inappropriately prescriptive. PacifiCorp’s specific objection is to inclusion of the term “real.” The company currently uses the real after-tax marginal WACC to calculate a levelized payment from the present value of nominal revenue requirements. The company then escalates this “real levelized” payment each year by the assumed rate of inflation. *PacifiCorp’s Opening Comments at 8.*

PGE recommends that the Commission adopt a planning “convention” that would have utilities “[d]iscount all future costs by the after-tax *incremental* weighted-average cost of capital” [emphasis added]. *PGE’s Opening Comments at 10.* The company does not explain its reasons for its exclusion of the term “real” or its proposal to use incremental rather than marginal WACC.

As noted in our opening comments, staff simply recommends that the Commission retain its requirement from Order No. 91-1552, which was reaffirmed in Order No. 93-695.

Staff agrees with PacifiCorp’s approach of using the real after-tax marginal WACC to calculate a levelized payment from the present value of nominal revenue requirements. Staff believes this approach is consistent with Order Nos. 91-1552 and 93-695. We also believe it’s a reasonable interpretation of the guideline as originally stated and we therefore recommend no changes.

With respect to PGE’s use of “incremental” rather than marginal, staff uses these terms as roughly substitutable with one another. The key is that both the incremental and marginal cost exclude any embedded costs of debt and preferred stock.

Staff notes that the assumed maturity date for the marginal debt for base case analyses should be a 5-, 7- and 10-year average.

PacifiCorp also questions the value of staff’s proposal to retain the Commission’s requirement in Order No. 90-1658, reaffirmed in Order No. 91-1552, that utilities should analyze how their preferred portfolio would change over a range of reasonable discount rates. While conceding that the analysis would be easy to do, the company states that its WACC is based on the company’s capital structure, which typically is not very volatile, and that such analysis would not be necessary in a stable inflation environment.

Staff still believes that the companies should analyze how their preferred portfolio would change over a range of reasonable discount rates even in periods of stable interest rates. Risk premiums, capital structures, and other factors change over time and can have an impact on the WACC.

Second substantive requirement*:* Staff agrees with PacifiCorp's proposed addition to the Commission's second substantive element: Uncertainty <u>and risk</u> must be considered. PGE makes a similar addition.

Third substantive requirement. Staff revised its proposed modification to the Commission's third substantive element in response to comments from PacifiCorp and PGE.

Regarding the second guideline supporting the third substantive requirement, PacifiCorp asked whether staff intended that electric utilities be required to analyze gas storage facilities and pipelines. We clarify that we do in the case where a utility is considering a new gas-fired power plant. For example, PGE recently contracted for storage at NW Natural's Mist facility in large part to serve its new Port Westward plant. PGE also needed to acquire firm gas transportation to Port Westward.

Also related to the second supporting guideline, NW Natural recommends the Commission use "Total Resource Cost" and avoided costs as the key cost metrics "to avoid problems in inter-fuel cost comparisons." The company further asserts that such fuel switching analysis should not account for public purpose funds for the above-market cost of new renewable resources or economic credits. *NW Natural's Opening Comments at 1 and 4.*

One of the Commission's objectives for 2005-06 is to "[c]omplete [a] study of whether to promote the direct use of natural gas to meet customer needs over its use to generate electricity for that purpose." Staff plans to issue a report on this subject. Therefore, any consideration of fuel switching in integrated resource planning should be addressed at a later date.

To the extent that NW Natural's comments about the Total Resource Cost test and avoided costs relate to conservation, staff reiterates that evaluation of conservation in integrated resource planning should consider both cost *and* risk, consistent with all other resources evaluated. If a utility retains responsibility for funding conservation programs, various types and amounts of conservation should be included in the portfolios tested. Total Resource Cost and avoided cost analyses do not model the actual operation of the utility system, nor do they take into account risks such as varying loads, fuel prices and so forth.

Staff's proposed cost metric for analysis of portfolios, present value revenue requirements (PVRR), accounts for the forward-looking costs to the utility. It is appropriate for the utilities to include in the PVRR analysis the amount of public purpose funds the utility expects to be available to support new renewable resources because the utility's expected costs will be reduced by that amount. Staff also recommends that the Commission require the utilities to use at least two measures of PVRR risk: one that measures the variability of costs and another that measures the severity of bad outcomes.

Staff also does not agree with NW Natural that in Total Resource Cost analysis, economic credits from outside the utility system – such as federal tax credits for renewable resource projects – should be excluded from the analysis.

Procedural Requirements (Proposed Guideline 2)

Staff agrees with PacifiCorp's recommendation to retain the guideline in Order No. 89-507 addressing the process for dealing with disputes on information requests. The Commission stated in that order at 5, "Any disputes which arise about whether information requests are relevant or unreasonably burdensome or whether a utility is being properly responsive may be submitted to the Commission for resolution." Staff has added this item to its proposed guidelines.

Plan Filing, Review and Updates (Proposed Guideline 3)

IRP Filing Cycle. Staff recommended in its opening comments that the Commission retain its requirement that resource plans "be updated by the utilities no less frequently than every two years." *Order No. 89-507 at 11.* Staff understood the requirement to mean that energy utilities must file an updated (final) IRP within two years of its last IRP filing. In other words, if a utility filed its final IRP on January 24, 2005, the next IRP, in final form, must be filed by January 24, 2007. Staff further recommended that the utility be allowed to request a waiver if it does not expect to take any significant resource action within two years.

In opening comments, PacifiCorp agreed with staff's proposal, and Idaho Power expressed no objection. The Utah and Idaho Commissions require the utilities to file a resource plan every two years. Also in opening comments, NW Natural expressed no opposition to staff's proposal to retain a two-year filing cycle.

However, staff believes the proposal by Citizens' Utility Board/Renewable Northwest Project and Northwest Energy Coalition (CUB/RNP/NWEC), that IRPs should be filed two years from the date of the previous IRP's *acknowledgment*, is reasonable. The proposal would help ensure the utility has the benefit of the Commission's decision on its previous IRP, including any direction for the next IRP, before undertaking the next round of planning. In combination with an annual action plan update, the Commission would continue to receive planning information on a timely basis. We therefore modify our position on IRP filing cycle in the attached proposal.

We believe PGE's proposal to require that an IRP (in its final form) be filed at least three years from the filing date of the company's previous (final) IRP also is reasonable, so long as the Commission requires substantive action plan updates. Such an update would cover changes in the company's load/resource balance, resource costs and resource acquisition activities, and other information indicating that the acknowledged action plan remains reasonable or that the modified actions the company is taking are appropriate.

Utilities that have a shorter filing cycle requirement in other states can continue to file their plans in Oregon according to that shorter cycle. A utility also may file more frequently than Oregon's required filing cycle if it finds itself in need of additional or different resources than those acknowledged in the previous IRP. If a utility believes filing *later* than two years from acknowledgment of the last IRP would be appropriate in a particular case, staff's recommendation for a waiver provision would offer the opportunity to do so.

To illustrate how the various proposals for filing cycles might work, staff provides an example below showing the timing of key IRP milestones under various filing cycles. In the first data row, we use the *actual* schedule for PacifiCorp's last two resource plans. In the next two rows, we show how the schedule might look under longer filing cycles. For these examples, we assumed that action plan updates are due on the anniversary date of the most recent IRP acknowledgment. Note that actual review and acknowledgment timelines vary considerably from plan to plan.

IRP Filing Cycle	**Prior IRP Filed**	**Staff's Final Recommendations and Proposed Order**	**Commission Acknowledgment**	**Annual Action Plan Update**	**Next (Final) IRP Filed**
Two years from filing last IRP	January 2003	July 2003	August 2003	October 2003*	January 2005
Two years from acknowledgment	No change	No change	No change	August 2004	August 2005
Three years from filing last IRP	No change	No change	No change	August 2004	January 2006

* PacifiCorp filed an action plan update on its own initiative.

Action Plan Updates. Staff agrees with PacifiCorp that the Commission should allow a utility to request a waiver from a requirement to submit an action plan update in a given year. Such a waiver request should confirm that there are no changes in conditions such as loads, expiration of resource contracts, supply-side and demand-side resource acquisitions, and resource costs *that affect the acknowledged action plan*, and that the company is proceeding on time with the action items in the acknowledged plan. As discussed in the second section of our reply comments, staff understands that IRP procedural requirements will be incorporated into administrative rules, and staff recommends a waiver provision be included in those rules.

Conversely, staff recommends that the Commission require the utilities to file an (informational) action plan update *sooner* than the mandated filing schedule if the company has decided to deviate significantly from its acknowledged action plan. Such a deviation could include, for example, not pursuing an item in the acknowledged action plan, or acquiring significantly more or less resources, or particular resource types, as indicated in the acquisition schedule in the plan.

In addition, staff recommends that utilities *not* file an action plan update if they will be filing a final IRP within six months of the update due date. Especially considering that the utilities file a draft IRP before the final IRP, there is no need for an update on the previous IRP in that case.

PGE recommends that updates be filed annually by the anniversary date of the acknowledged IRP. Staff agrees and modifies its proposal accordingly.

Avista opposes an annual action plan update unless it is coupled with a lengthening of the IRP filing cycle from two years to three years. The company notes that it would be in the middle of the next planning cycle and, because staff is engaged in that process, we would have access to information that we propose be included in an update.

Similarly, Cascade states that *required* annual updates may make sense only if the IRP filing cycle is lengthened to three years. The company notes that other filing requirements, such as the annual demand-side management (DSM) review and purchased gas adjustment (PGA) filing, provide the same information to staff.

Staff agrees that some of the information we recommend be provided in action plan updates would be available to Commission staff during the annual PGA and DSM reviews. However, those reviews typically do not look at changes in loads, expiration of resource contracts, all of the supply-side and demand-side resource acquisitions, and resource costs *that affect the acknowledged action plan*. For example, PGA filings only show how changes in gas purchases may affect the cost of gas to be allowed into customers' rates over the next year. Further, the *Commission* would not be fully updated on the gas utilities' planning and acquisition processes, which staff understands would be a key objective of an annual update on the acknowledged IRP action plan.

Finally, staff's modified positions — that IRPs be filed within two years of Commission *acknowledgment,* action plan updates be filed within one year of acknowledgment (rather than within one year of IRP filing), and a general waiver provision be included in IRP administrative rules — should go a long way toward overcoming Avista and Cascade's objection to requiring annual action plan updates.

As to what should be included in an action plan update, Avista expressed concern that staff's proposal included "a utility request for an action that is not part of its most-recently acknowledged IRP." *Avista's Opening Comments at 3.* Staff did not make such a recommendation. However, if a utility chooses to do so, it could request in its action plan update that the Commission acknowledge a change in its action plan, with the appropriate supporting analysis.

Cascade characterizes the action plan updates as “an annual IRP filing, which would be both costly and redundant.” *Cascade’s Opening Comments at 2.* Instead, staff proposes that the action plan update “provides an assessment of what has changed since acknowledgment that affects the action plan….” *Staff’s Opening Comments at 8.* Thus, there is no call for a utility to repeat what’s already in its most recently acknowledged IRP, or undertake extensive analyses in support of the update.

IRP Review. Avista proposes that staff’s and parties’ comments on the final IRP be due within three months of a utility’s filing. Alternatively, the company suggests that a deadline be negotiated among parties for each IRP.

IRP analysis has gotten more complex, the consideration of risk and uncertainty in decision-making is given more weight, and the filed documents are longer. Staff and parties need more than three months to make information requests, review the material, and provide both initial comments and reply comments. Further, because staff prepares not only its comments and recommendations to the Commission, but a draft proposed order for parties’ comments and a final proposed order for the Commission’s consideration, a three-month deadline is unreasonable. To the extent that a given IRP is less complex than others, parties could negotiate a shorter timeline for comments than staff’s proposed six months, just as they are able to do today.

PacifiCorp concedes that Order No. 89-507 supports a continuation that “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.” However, the company seeks clarification that staff does not intend that such direction be a condition for the Commission’s acknowledgment of the currently pending IRP. Our report in LC 39 confirms that “staff agrees with PacifiCorp’s distinction that such direction should not constitute a condition for acknowledgment for the IRP at hand.” *Staff Report, Docket No. LC 39, July 22, 2005.*

Proposed Guideline 5

Guideline 5 in staff’s original proposal stated: “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.”

PacifiCorp recommends that the Commission not adopt this guideline because the company believes it duplicates one of staff’s proposed elements of an IRP: “Construction of a representative set of resource portfolios to test various fuel types, technologies, lead times, in-service dates, durations and locations.”

Staff agrees that these provisions are duplicative in part. However, guideline 5 is more extensive because it refers both to the evaluation phase and the action plan.

Another proposed element of the plan in staff's original proposal also is relevant: "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."

Staff's final proposal, attached, eliminates guideline 5, adding portions of that guideline to the two plan elements cited here as follows:

- Construction of a representative set of resource portfolios to test various operating characteristics, resource types, fuels and sources~~types~~, technologies, lead times, in-service dates, durations and general locations – system-wide or delivered to a specific portion of the system
- 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, with the key attributes of each resource specified as in portfolio testing

Transmission and Distribution System Savings/Distributed Generation
(Proposed Guidelines 6 and 14)

PacifiCorp asserts that it "cannot capture the potential savings related to the distribution system in its IRP, because the IRP is a system-wide planning function at the transmission level. Distribution planning and deferrals associated with the distribution system are based on specific projects and their locations." *PacifiCorp's Opening Comments at 15.*

Staff points out that the utilities use "proxy" resources with defined locations for their IRPs, in large part because they need to estimate the associated transmission costs for modeling purposes. In addition, utilities specify which portion of the utility system shows a resource need, due to load growth in a particular area, expiration of contracts for resources or transmission, or aging equipment.

These are the same conditions needed to identify in the IRP opportunities for distribution system cost savings for resources that have the potential to significantly reduce such costs: energy efficiency targeted to peak loads in a given area, demand response, distributed generation, liquefied natural gas and gas storage.

Staff agrees with PacifiCorp that utilities should not apply a global value to potential distribution system savings, because such value is location-dependent. That's why staff recommends in guideline 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*." [Emphasis added]

Staff clarifies that this guideline is intended to improve analysis of well-located distributed generation that has the potential to defer or even avoid some distribution and transmission investments that otherwise would be required. For example, well-located combined heat and power facilities in the fast-growing Salt Lake City area could help relieve transmission bottlenecks into that region as well as the need there for new or upgraded distribution substations, or other types of distribution facilities.

PacifiCorp expresses concern about forecasting a feasible and dependable amount of distributed generation capacity suitable for long-term planning. Staff believes that relying on customer-sited combined heat and power facilities, which often are wholly customer- or third party-owned, is not necessarily any more risky than utility investments in conservation at a particular customer site. In both cases, if the customer goes out of business, the resource the utility was counting on is no longer contributing to the utility's mix. At the same time, however, the customer's load is gone. Thus, such resources are well matched to customer needs.

Further, Section 1253 of the Energy Policy Act of 2005 removed restrictions on utility ownership of Qualifying Facilities under the Public Utility Regulatory Policies Act of 1978 (PURPA). Previously, PURPA rules limited utility ownership to 50% of the facility. Therefore, there is no longer any such restriction on what a utility may do to help bring combined heat and power projects on-line.

Conservation (Proposed Guideline 7)

PacifiCorp asserts that proposed guideline 7 is redundant with substantive requirement 1 (guideline 1). Staff disagrees, but we believe that guideline 7 as written could be moved below substantive requirement 1. We have not done so in our attached final proposal, however. We believe it is preferable to have a separate guideline addressing treatment of conservation and new renewable resources in part because of public purpose provisions in ORS 757.612.

PacifiCorp also believes that staff's proposal that conservation resources be evaluated under all possible futures may be too prescriptive. Staff has modified this part of its proposal to be required only for the *top-performing* portfolios. It is important to evaluate various amounts and types of conservation resources for at least these portfolios because of conservation's risk reduction benefits and the impact it may have on the size and timing of other resource additions.

According to PacifiCorp, guidance calling for evaluation of various amounts and types of conservation in portfolio analysis raises concerns about other states' perspectives on the appropriate methodology for analyzing conservation in the resource planning process. PacifiCorp also notes that conservation costs are assigned *situs* to each state. For similar reasons, the company rejects staff's proposal that utilities periodically conduct conservation assessments of their service area.

A guideline calling for utilities to "fully analyze conservation resources in portfolio modeling on par with supply-side resources, accounting for the cost and risk reduction benefits of conservation resources for the top-performing portfolios evaluated" does not preclude the utilities from performing analyses preferred by other states. In fact, a comparison of the two methodologies may be useful — the portfolio analysis staff recommends versus the company's current "decrement" approach, which considers only cost reductions on a deterministic basis and does not consider *expected* costs due to fuel price, load volatility and other risks.

Rate Design as a Resource (Proposed Guideline 8)

ICNU recommends that the Commission eliminate its guideline from Order No. 89-507 (at 10) that "…rate design should be treated as a potential demand-side resource." *ICNU's Opening Comments at 11-12.* Staff's understanding is that ICNU is concerned that a utility would include *mandatory* time-varying pricing in its IRP as a demand response resource it intends to pursue and request acknowledgment to do so. However, the examples staff cited in its opening comments are all *voluntary* programs that use rate design to achieve demand response — two-part real-time pricing programs (offered by Georgia Power and PGE, for example), California's Statewide Pricing Pilot for small customers, and the Time of Use portfolio option for Oregon's residential and small business customers. Other examples are the energy/demand buyback programs industrial customers participated in during the Western energy crisis and which remain in place today, PacifiCorp's interruptible rate option offered to large customers last winter, and the load curtailment contracts PacifiCorp has in place in Utah with large industrial customers.

ICNU also may be concerned that any such programs, including accompanying rate structures, would be designed as part of the IRP process. Staff and other parties in this proceeding recommend that the Commission reaffirm its position in Order No. 89-507 that ratemaking will not be part of the IRP process.

Unless rate design is treated as a potential resource in resource planning, the utilities will not necessarily include in their portfolio analyses and action plan voluntary demand response programs that rely on rate design (as opposed to utility programs that rely on direct load control of air conditioning, water and space heating, irrigation and lighting loads). Thus, utilities will not take into account the expected load reductions during peak hours and will plan to build more (and more expensive) capacity resources than necessary.

Further, simply including expected load reductions from rate design-based demand response programs in the load forecast, instead of analyzing programs as portfolio options, does not allow for a fair comparison with supply-side resources. At staff's request, for example, PacifiCorp calculated the *risk* benefits for its preferred portfolio in its 2004 IRP after adding DSM resources — both direct load control and conservation outside of Oregon. Such risk analysis is routinely performed for alternative portfolios composed of various *supply*-side resource options. The DSM resources reduced the expected cost (risk) over all futures tested by more than 6% on average, and by about 5% in the worst-case futures. Utilities will not necessarily perform this type of analysis unless the Commission reaffirms that rate design should be considered as a potential demand-side resource and that it be considered in portfolio cost and risk analysis.

Regarding ICNU's characterization of Puget Sound Energy's opt-out (voluntary) time of use pricing program for residential and small business customers in 2001-02, staff points out that residential participants consumed about 5% less electricity during peak hours than consumers paying flat rates — a sizable benefit to the utility and its ratepayers during the Western energy crisis. Further, throughout most of the program, most participants paid less than they would have on flat rates.

Nearly all customers were satisfied with the program, which included Web site access to energy use by time of day. More than 90% of participants took actions to change their energy use as a result of the program. Nearly all said they would recommend it to others.

The program was changed in July 2002, when a monthly meter fee was added to help pay for metering and data collection costs. On average, residential customers paid 80¢ per month more from July 2002 to September 2002 than they would have under flat rates. The average small business paid $1.16 more per month during that period. As a result, Puget Sound Energy ended the program in November 2002. Hardly a disaster, but it does raise questions about meter charges, the program's small rate differential between on- and off-peak rates, and whether the addition of automated control technology would have improved peak demand reductions and consumer savings. *See staff''s report, "Demand Response Programs for Oregon Utilities," presented at the Commission's June 3, 2003, meeting.*

Environmental Compliance Costs (Proposed Guideline 9)

ICNU makes several recommendations and arguments regarding the consideration of external environmental costs in the IRP. Specifically ICNU:

- Recommends that the Commission either remove the requirement that the IRP be “consistent with the long-run public interest” or clarify that this obligation does not require utilities to consider external social and environmental costs
- Argues that it is inappropriate to require customers to pay higher electric rates by including the costs of complying with environmental laws that have not been enacted
- Recommends that the Commission “not require utilities to consider specific environmental risks and should only acknowledge those risk factors that are focused on protecting ratepayers from potential harms”
- Argues that requiring electric ratepayers to pay for external social and environmental costs may violate ORS 757.612
  ICNU’s Opening Comments at 7-9.

ICNU’s arguments and recommendations are based on a misunderstanding of the role that consideration of external environmental costs play in the current IRP process.

In Order No. 93-695, the Commission concluded that it did not have clear statutory authority to impose external environmental costs on a utility, either directly by requiring the utility or its customers to pay the external costs, or indirectly by penalizing the utility for choosing a resource with higher external costs*. Order No. 93-695 at 2-3.* However, the Commission concluded that it may require utilities to consider in their resource plans the likelihood that external costs may be internalized in the future. To date, consideration of external environmental costs in IRPs has been consistent with the Commission’s conclusions in Order No. 93-695.

ICNU is correct that the consideration of external environmental costs is limited in the IRP process. However, staff disagrees with the extent of the limitations envisioned or recommended by ICNU. First, it is not necessary for the Commission to either remove the requirement that the IRP be “consistent with the long-run public interest” or clarify the role that consideration of external environmental factors has in the IRP process. This clarification was made in Order No. 93-695, in which the Commission concluded that it did not have clear authority to either directly or indirectly require the utility or its customer to pay external environmental costs and, thus, that it would not do so. On the other hand, saying that utilities need not consider external environmental costs is inconsistent with Order No. 93-695 and would defeat the purpose of IRP. The utilities must consider risks associated with external environmental costs — specifically, that they may be internalized and included in energy rates in the future — in order to engage in meaningful integrated resource planning.

To the extent that ICNU argues it is inappropriate to require customers to pay higher electric rates by including the costs of complying with environmental laws that have not yet been enacted, staff believes that ICNU fails to distinguish between consideration of the risk that certain external costs may at some point become internal costs and consideration of the external costs themselves. As the Commission noted in Order No. 93-695, it is appropriate for utilities to consider the likelihood that external costs may be internalized in the future, and to quantify the nature and extent of this risk through various analyses. It also is appropriate for the utility to make resource decisions based in part on these analyses. Staff disagrees that by allowing utilities to base their resource decisions in part on such analyses, the Commission is allowing utilities to charge customers higher rates to recover costs of complying with environmental laws that have not yet been enacted.

Staff also disagrees with ICNU's recommendation that the Commission "should not require utilities to consider specific environmental risks and should only acknowledge those risk factors that are focused on protecting ratepayers from potential harms." Whether risks are classified as "environmental" or "social" risks is irrelevant to whether they have the potential to become costs for the utility and its customers in the future.

Finally, staff believes that ICNU's argument that requiring customers to pay for external social and environmental costs violates ORS 757.612 is irrelevant in this investigation into the IRP process. ORS 757.612 prohibits an electric company from including certain types of costs in rates, including above-market costs of new renewable energy resources. It does not prohibit electric companies from assessing risk associated with external costs, including environmental compliance costs, to make determinations regarding the least-cost and least-risk resource portfolio.

Put more plainly, a utility's choice to include renewable resources in its least-cost, least-risk portfolio, based in part on its base-case environmental adders and its sensitivity analyses on potential environmental compliance costs, is not putting in rates the above-market costs of new renewable resources, but choosing resources based on expected costs in the future, as well as risk. Such utility action would be consistent with staff's proposed goal of integrated resource planning, which is that the utility select a portfolio of resources that has the "best combination of expected costs and associated risks and uncertainties for the utility and its ratepayers."

Consideration of Damage and Mitigation Costs. PacifiCorp objects to staff's proposal that "Compliance cost projections should consider damages from pollution and estimates of mitigation costs." The company notes that regulatory bodies consider human health and environmental impacts when setting emissions control levels. Therefore, the company asserts, it is already considering damage costs associated with emissions when it determines its compliance costs. PacifiCorp also says that utilities should not be required to perform separate analysis of damage or mitigation costs.

Staff agrees that damage and mitigation costs are taken into account in setting emissions requirements. But our point is that tomorrow's emissions requirements may not be the same as today's in part because of changes in estimated costs for damages and mitigation. Staff did not intend for the utilities to undertake their own studies of such costs. Rather, we assumed that the utilities would rely on studies published by reliable sources.

While we continue to believe that estimates of actual mitigation costs for pollution damages indicate the maximum extent of costs that could be included in rates in the future, and therefore are appropriate for the utility to consider in long-term resource planning, we propose that such consideration be discretionary. We have modified our related guideline accordingly.

Gas Utilities and CO_2. Avista requests clarification of staff's proposed guidelines related to global warming as they apply to a natural gas utility. As in Order No. 93-695, staff makes no distinction between electric and natural gas utilities regarding potential compliance costs related to greenhouse gases. Staff recognizes, however, that consideration of fuel type in electric utility IRPs focuses more attention on such potential costs.

Regardless of the type of utility, assumptions about compliance costs related to greenhouse gases affect the determination of the appropriate levels of conservation over the planning horizon. It is in this analysis that a natural gas utility would "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."

***Probability Weightings in Risk Analysis*.** CUB/RNP/NWEC propose that the sensitivity analyses required by Order No. 93-695 ($0, $10, $25 and $40 per ton CO_2 in 1990$) be given probability weightings in the (stochastic) risk analysis, and not be separately included in the IRP. *See CUB/RNP/NWEC Opening Comments at 3.*

Staff believes it would be difficult to do so because there are no historical values in the U.S. for CO_2 compliance costs other than zero, which may not be a good predictor of the future. That's why staff's proposed guidelines under substantive requirement 2 (uncertainty <u>and risk</u> must be considered) include the following: "The analysis must recognize the historical variability of these factors as well as future scenarios."

Staff believes that at this time, utilities should be allowed to continue to demonstrate compliance with the Commission's mandated CO_2 sensitivity analyses by performing separate scenario analyses. At the same time, a utility may demonstrate in a future IRP that it is reasonable to use in stochastic risk analysis a probability-weighted distribution of the Commission-specified CO_2

adders or other adder levels – based on legislative proposals or state requirements under consideration, or European trading markets for CO_2 offsets, for example.

Staff noted in its opening comments that "The utility should assign probability distributions to uncertainties to explicitly value resource options that reduce risk." *Staff's Opening Comments at 7.* The point is that we believe the assignments should be based on the *utility's* assessment of such distributions. For example, PacifiCorp's base case CO_2 cost in its 2004 IRP recognized the timing uncertainty of CO_2 regulation by phasing in expected costs at $4.19/ton in CY 2010, representing a 50% probability of an $8.38/ton allowance cost in 2010$.

Moreover, staff finds at least as valuable scenario analyses that indicate how the utility's preferred portfolio might *change* under possible futures. In its most recent IRP, for example, PacifiCorp found that at a regulatory cost of $33/ton CO_2 (1990$), an IGCC plant with CO_2 capture and sequestration would be cost-effective, compared to a supercritical pulverized coal plant without it.

Further, we believe it would be highly valuable in IRP to perform scenario analyses that consider *combinations* of futures, such as low CO_2 compliance costs with high gas prices, high CO_2 compliance costs with high gas prices, low load growth with low market prices, and so on. (We note that high CO_2 compliance costs would affect electric market clearing prices, natural gas prices and allowance costs for other pollutants. PacifiCorp recognized this fact in its CO_2 scenario analyses.) Data on those combinations may not be available from the utility's stochastic risk analysis.

Suspended Particulates. Staff continues to believe that sensitivity analyses should no longer be required for suspended particulates, as required by Order No. 93-695. However, we removed this statement from our proposed guideline and recommend the Commission instead add similar language in supporting text in the order.

Updated CO_2 Adders for Sensitivity Analyses. In our opening comments, staff recommended that the Commission update the CO_2 values in Order No. 93-695 from 1990 dollars. We provided two examples of updated values, in PacifiCorp's and Idaho Power's most recent IRPs. We recommend that the Commission choose one of these updated set of values or develop updated values as of the date of its order in UM 1056. Therefore, the Commission should treat simply as a placeholder for those updated values our proposed guideline, "Utilities also should analyze the range of potential CO_2 regulatory costs in Order No. 93-695, from zero to $40 (1990$)."

Planning for Customers Served by Alternative Suppliers (Proposed Guideline 10)

Gas Utilities. The three gas utilities objected to staff's proposed guideline as it relates to gas customer loads served by alternative suppliers. Gas utilities do not plan for non-core load, and their tariffs state what they would do if a non-core customer returned to firm sales service.

Staff has removed references to gas utilities in its proposed guideline related to planning for customers with access to alternative suppliers. Nonetheless, gas utility IRPs should include a discussion of what would happen if all or a portion of customers that have bypassed the gas utility or are only receiving transportation service returned to firm sales service, along with scenario analysis if needed. The discussion and any scenario analysis should include the impact on the resources the utility has available or could make available to meet such requests, the associated costs, and any impacts on system operations or integrity and service reliability. The Commission could include such an expectation in its order in this proceeding.

Electric Utilities. At the Sept. 22, 2005, workshop, Judge Logan asked parties to clarify how utilities should plan for direct access-eligible customers.

With annual opt-out provisions and all customers retaining the right to return to a cost of service rate, today PGE and PacifiCorp are forced to consider all customer loads in integrated resource planning, except for those participating in PGE's five-year opt-out. Those customers receive an incentive to remain direct access customers through a transition adjustment deemed to be zero after the fifth year. Further, they are required to provide two-year advance notice before returning to cost of service rates.

If the Commission requires the utilities to offer a permanent opt-out choice for nonresidential customers, with no ability to return to cost of service rates, the utility could establish a long-term transition adjustment for customers that permanently opt-out and not include these customers in its resource planning.

Multi-State Utilities (Proposed Guideline 11)

PacifiCorp supports staff's guideline related to multi-state utilities and agrees that it could include in its IRPs a discussion of whether any state-mandated objectives require a deviation from the company's preferred portfolio. Idaho Power also supports staff's position to continue resource planning on a system-wide basis and requests continued compatibility in IRP requirements between Idaho and Oregon.

While Cascade agrees with staff's proposed guideline for multi-state utilities, the company expresses concern that staff's explanation reaches into the analysis of other states' IRP processing. Avista recommends that staff's guideline be modified as follows:

> Multi-state utilities should plan their generation and transmission systems, or gas supply and delivery, on an integrated system basis <u>for common costs </u>that achieves a least-cost/least-risk resource portfolio for all their retail customers. *Avista's Opening Comments at 4.*

Both gas utilities assert that the Commission should not require a multi-state utility IRP to include planning for resources that involve *no* cost to Oregon customers if the jurisdiction that needs the resource does not require that a means to satisfy that need be included in the IRP. Staff agrees, provided that the plan demonstrates that the full costs of that resource will be directly assigned to the other state and Oregon customers will bear no costs, directly or indirectly.

Nonetheless, staff finds the additional language proposed by Avista confusing. For example, PacifiCorp's Multi-State Protocol, approved by the Commission in Order No. 05-021 (UM 1050), requires that each state pay for conservation costs *situs*. However, each state pays for supply-side and transmission resources based on its allocated share of load. Conservation reduces the need for supply-side and transmission resources, reducing total system costs. (Relative conservation acquisition rates may affect each state's share of those costs.) Therefore, rates for PacifiCorp's Oregon customers are affected by conservation acquisition in other states, even though costs for conservation programs are not common costs.

To accommodate Avista and Cascade's concern, staff recommends in the attached proposal an alternative modification to our initial proposal.

Ratemaking Treatment (Proposed Guideline 12)

Guideline 12 in staff's original proposal states, "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."

While agreeing with staff's proposed concept, PacifiCorp does not believe it needs to be included as a guideline. Staff agrees and has eliminated this guideline from its final proposal. However, we strongly recommend that the Commission address this issue elsewhere in its IRP order.

Reliability/Resource Adequacy (Proposed Guideline 13)

PacifiCorp "proposes that utilities continue to be allowed to explore the difficult task of establishing minimum resource adequacy levels through public processes …and, if appropriate, new measures implemented in future IRPs." The company asserts that regulators should not be "overly prescriptive at this time." *PacifiCorp's Opening Comments at 19-20.*

PGE recommends that the Commission adopt the following planning "convention" for reliability to be used in IRP "unless a proponent establishes that it makes more sense…to do something different":

> Develop and support the capacity planning assumption used in the plan, including an analysis of reliability standards, such as appropriate planning margins or resource adequacy requirements, recognizing that higher reliability carries a higher ongoing fixed cost. *PGE's Opening Comments at 9-10.*

PacifiCorp asserts that it is not practical at this time to determine an optimal planning reserve margin for each year for all futures considered. This is not a proper characterization of staff's proposed guideline. Rather, staff's proposal calls for the electric utilities to "analyze planning margin within the risk modeling of the actual portfolios being considered." That is, the analytical model the utilities use should model their existing resources as well as the new resources they are actually considering.

Further, the model electric utilities use for evaluating planning reserve margin should at a minimum account for the same risks as in other IRP risk modeling — varying loads, forced outages, hydro availability, and fuel and market prices, as well as market purchases within transmission constraints. This is consistent with PacifiCorp's approach for its 2004 IRP.

Staff noted in its opening comments that we believe a utility would meet staff's proposed guideline if it conducted reliability analysis on the top-performing resource portfolios, not all portfolios. It is not sufficient to conduct the analysis only on the company's preferred portfolio, because the Commission may have a different view than the utility of which portfolio is best for ratepayers. We have clarified our guideline accordingly. We also have clarified that the guideline would not require at this time that data be presented by future, but should provide information by year on loss of load probability, planning reserve margin, and expected and worst-case unserved energy.

Showing the results of the analysis by year is not the same as ensuring that the planning margin is "optimal" each year. Rather, such results would simply inform the Commission what the planning margin is expected to be in a given year, and how reliability data might look under expected and worst-case conditions in that year. PacifiCorp provided such year-by-year data for its 2004 IRP in response to staff's information requests, and staff presented that information to the Commission for its consideration.

If IRP accomplishes anything, it is a determination of the need for and timing of resources to meet forecasted loads and a planning margin. Staff's proposal would establish guidance for the utilities to give the Commission what it needs to determine whether the utility's selected planning margin is appropriate, while providing sufficient flexibility for analytical improvements over time.

Identifying Procurement Strategy (Proposed Guideline 15)

Electric utilities. PacifiCorp does not agree with staff that utilities should identify in their action plans their planned acquisition strategy for each resource, including whether they intend to use competitive bidding and consider a utility-owned resource in that process. PGE's proposal "[d]oes not require an acquisition strategy for each resource." *PGE's Opening Comments at 11.*

Order No. 89-507 (at 11) states, "The Commission believes that competitive bidding may play an important role in LCP. A utility's least-cost plan must consider the role of competitive bidding in planning for and acquiring new resources. Each utility should identify in its plan how and to what extent competitive bidding may be employed in its acquisition of resources."

The Commission reaffirmed its intent in Order No. 91-1383 (at 1): "The utility should indicate its intention to conduct a competitive bid in its least-cost plan's two-year action plan. This is subject to public review and Commission acknowledgement." The Commission also clarified (at 5) that, "In its review of each utility's least-cost plan, the Commission will examine the utility's participation in the bidding process." At 1, the Commission stated that "The primary role of the Commission will be to establish a fair competitive bidding process and determine *whether a proposed project is consistent with the soliciting utility's least cost plan*." [Emphasis added.]

Therefore, staff's proposed guideline is consistent with previous Commission orders on resource planning and competitive bidding.

Staff agrees with the Northwest Independent Power Producers Coalition and CUB/RNP/NWEC that the utility should identify transmission arrangements if it plans to consider a utility-owned site. Staff has added this to its proposed guidelines. The utilities use "proxy" resources to determine the cost estimates for the resources they are considering for the portfolios tested in the IRP process. Each of these proxy resources is assumed to be in a specific location, precisely because that is the only way to assign a reasonable estimate of transmission costs.

Gas utilities. Staff's proposed guideline 15 required that gas utilities *describe* their proposed bidding process for gas supply and transportation. All three gas utilities filed comments on this guideline.

Cascade does not disagree with staff's proposal, but is concerned that staff's guideline is closely linked to the competitive bidding requirements being reviewed in Docket UM 1182. Staff disagrees. Staff's proposal for natural gas utilities is simply a restatement of Commission statements in Order 89-507, described above. However, staff agrees with most of Avista's proposed modifications to the guideline to clarify what is expected in gas utility IRPs, and we have revised our proposal accordingly.

NW Natural does not agree with staff's initial proposal that the gas utilities' competitive bidding processes should be "tied to the IRP cycle." Staff's modifications to the guideline noted above clarify that the gas utilities should describe their competitive bidding processes in the IRP, or provide to the Commission following IRP acknowledgment a description of those processes. Such a description should include the utility's basic underlying assumptions. We agree with NW Natural that the gas utilities often engage in competitive bidding in an informal manner, and that the results of that process are reviewed as part of the annual PGA filings.

COMMENTS UNRELATED TO STAFF'S PROPOSED REQUIREMENTS AND GUIDELINES

Administrative Rules (Issue 7)

Judge Logan requested at the Sept. 22, 2005, UM 1056 workshop that parties state which types of IRP guidelines they would not object to including in administrative rules, noting that Oregon law requires at least the administrative requirements for IRP to be placed in rules.

Staff therefore recommends that proposed guidelines 2 and 3, as modified in the attached document, be incorporated into administrative rules. Regarding other IRP guidelines, staff continues to believe they could be set out through a Commission order in this docket and updated as needed through subsequent Commission orders to retain the flexibility of the planning process over time. That said, staff guideline 4, describing the minimum elements that must be included in a resource plan, could be included in rules without ill effects. Staff guideline 1, which sets forth the substantive requirements of IRP and how a utility should demonstrate compliance, also may be appropriate for inclusion in rules.

Staff recommends that the IRP rules include a general waiver provision. Such a provision may be of particular use for a utility that does not need to acquire resources in the near future and may want an exemption from a requirement to file its next IRP according to the mandated filing cycle.

Significance of Acknowledgment (Issue 10)

PacifiCorp notes that the Commission's prudence standard determines whether a given utility decision or action was prudent based on the information that was known or knowable at the time the utility made the decision or took the action. The company argues that the IRP public input process is particularly well-suited for parties to present information then known and knowable that they believe is relevant to the utility's planning process. In light of these circumstances, PacifiCorp asks the Commission to clarify that it will not revisit in a subsequent proceeding the question of what was known or knowable at the time of that IRP planning cycle. *PacifiCorp's Opening Comments at 21-22.*

PacifiCorp's request is inconsistent with the predicates underlying the least-cost planning process and staff opposes PacifiCorp's request.

As stated in Order No. 89-507, ratemaking decisions will not be made in the resource planning process. When a utility requests approval of expenditures or inclusion of a plant in rate base, the utility must demonstrate the justness and reasonableness of its proposed rates at the time the resource comes on line. No party has advocated changing these fundamental principles.

PacifiCorp's recommendation that the evidence that may be used in a rate proceeding should be limited by evidence adduced during the IRP process is inconsistent with the premise that ratemaking treatment is decided entirely in a rate proceeding. The IRP process is intended to inform the Commission's decisions regarding the appropriate ratemaking treatment of new resources, not limit the information the Commission can consider when making those decisions.

In its opening comments (at 7-8), PGE marked up the portion of Order No. 89-507 related to ratemaking decisions. PGE states that its markup is intended to recognize that it is common practice today for utilities to enter into contracts for resources. PGE asserts that it is not otherwise changing the content.

Staff agrees with PGE that the Commission's order in this proceeding should recognize contracted-for resources. However, staff objects to PGE's proposed changes.

First, PGE proposes to eliminate the statement from Order No. 89-507 at 6, "Ratemaking decisions will not be made in the Least Cost Planning process." Second, PGE proposes to replace the Commission's statement that "Under ORS 757.355, the cost of a resource may be included in rates only if the resource is 'used and useful'" (also at 6) with, "The resources must be available for service when inclusion in rates is requested." While ORS 757.355 may not apply to resource contracts such as power purchase agreements to the extent they have no rate base impact, the "used and useful" standard, and not a lesser one, must apply for plants to be included in rate base. Finally, PGE recommends other changes that inadequately describe how costs get included in rates.

The Commission should clearly restate in its order in UM 1056 that ratemaking decisions will not be made in the resource planning process and reaffirm its prudence standard. The Commission also should recognize that ORS 757.355 may not apply to resource contracts to the extent they have no rate base impact.

Separate Section of Order for Gas Utilities

Staff does not agree with Cascade that IRP requirements for gas utilities should be placed in a separate section in the Commission's order in this proceeding. Nearly all of the issues in this docket apply to the gas utilities. Staff has indicated where a particular provision applies only to electric utilities or to gas utilities. Unless otherwise specified, staff's proposed requirements and guidelines are intended to apply to all energy utilities.

Modeling Costs of Incremental Gas Transportation and Electric Transmission (Issue 11b)

NW Natural states that “The guideline for issue 11b is written as though there is a world of difference between MC [marginal cost] and LRIC [long run incremental cost]. 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.” *NW Natural’s Opening Comments at 21.*

Avista notes that by some standards, marginal cost and incremental cost are used interchangeably with the same meaning. *Avista’s Opening Comments at 6.*

PacifiCorp comments that the important concept is that embedded costs are sunk costs and therefore irrelevant to forward looking decision making. *PacifiCorp’s Opening Comments at 22.*

Staff agrees that the terms “incremental” and “marginal” are roughly substitutable with one another. The key is that both incremental cost and marginal cost exclude any embedded or sunk cost of gas transportation or electricity transmission.

Further, the only costs that the utility should include in IRP for incremental gas transportation or electric transmission are reasonable estimates of the future incremental *costs the utility would expect to incur* to meet its customers energy/capacity needs. In PacifiCorp’s 2004 IRP, for example, the company tested a portfolio with new transmission to Wyoming to acquire a lower-cost coal resource (Portfolio F). The company assumed that it could share with Idaho Power a larger transmission line, for economies of scale. Therefore, PacifiCorp included only two-thirds of the cost of the new transmission line in its cost assumptions for that portfolio. Such a cost split mimicked an existing agreement between the two companies.

Staff's Proposed Requirements and 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 should 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.

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   Two, uncertainty and risk 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 should recognize the historical variability of these factors as well as future scenarios.

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

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   - The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities also should 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

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[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.

- 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.
  - Analyze how their preferred portfolio would change over a range of reasonable discount rates.
- The utility should explain how its resource choices appropriately balance cost and risk.

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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. Any disputes that arise about whether information requests are relevant or unreasonably burdensome or whether a utility is being properly responsive may be submitted to the Commission for resolution.
   - 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 through aggregation or shielding of data or some other mechanism.
     - The Commission allows information that is exempt from disclosure under the Oregon Rules of Civil Procedure or 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.

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3. Plan filing, review and updates will follow this schedule:
   - The utility must file an integrated resource plan within two years of IRP acknowledgment. If the utility does not intend to take any significant resource action within two years, the utility may request a waiver.

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   - The utility must present the results of its filed plan at a Commission public meeting prior to the deadline for written public comment.

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   - 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 acknowledgment anniversary date. The utility must file an update before that date if it is planning to deviate significantly from its acknowledged action plan. This requirement is waived if the utility will be filing its next IRP in final form within six months of the update's due 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)

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4. At a minimum, the plan must include the following elements:

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   - 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 operating characteristics, resource types, fuels and sources, technologies, lead times, in-service dates, durations and general locations – system-wide or delivered to a specific portion of the system

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- 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, with the key attributes of each resource specified as in portfolio testing (Issue 9)

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5. 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)

6. Utilities should consider the availability of public purpose funds in assessing the optimal level of new renewable resources to acquire. They also should 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.

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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 for at least the top-performing portfolios 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.

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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 a third party funds and administers 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)

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7. 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. Utilities should use these supply curves to evaluate demand response in the cost and risk modeling of portfolios. (Issue 14)

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8. Utilities should include in their base-case analyses the regulatory compliance costs they expect for carbon dioxide (CO_2), nitrogen oxides, sulfur oxides and mercury 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

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changes in state and federal requirements or their implementation. Utilities should explain the basis for their compliance cost projections, which may take into account published estimates of damage and mitigation costs. (Issue 15)

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

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10. 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. If there is a resource need in a state other than Oregon, and the other state does not require that the resource plan include a means to satisfy that need, the Commission will not require the plan to include such analysis if the plan demonstrates that the full costs of that resource will be directly assigned to the other state and Oregon customers will bear no costs directly or indirectly. (Issue 8)

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Deleted: 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

11. 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, expected planning reserve margin, and expected and worst-case unserved energy should be evaluated by year for each top-performing portfolio.
- 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)

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12. 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)

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13. The utility should identify in the action plan its acquisition strategy for each resource. Gas utilities should either describe in the IRP their bidding practices for gas supply and transportation or provide to the Commission a description of their bidding processes following IRP acknowledgment. Electric utilities

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CERTIFICATE OF SERVICE

I certify that on September 30, 2005, I served the foregoing upon the parties hereto by sending a true, exact and full copy by regular mail, postage prepaid, by shuttle mail or hand delivery and by electronic mail to:

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