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September 30, 2005

Oregon Public Utilities Commission
Attn: Filing Center
550 Capital St N.E. Suite 215
Salem, Oregon 97308-2148

Re: Staff's Proposed Guidelines, Integrated Resource Planning Requirements (Docket UM 1056)

Dear Filing Center:

Enclosed for filing is Avista Corporation's reply comments in the above-captioned docket. Avista is resubmitting its original comments filed September 9, 2005 pursuant to ALJ Logan's request to mark up Staff's proposed guidelines (which have not been substantively changed since September 9th) in the preferred format. We do so recognizing that there has not been an opportunity for parties to review Staff's reply comments, which will be filed coincident with these comments.

This document is being filed by electronic mail with the Filing Center. Please direct any questions regarding this filing to Kevin Christie at (509) 495-2001, or myself at (509) 495-8706.

Sincerely,

/s/ Bruce Folsom

Bruce Folsom
Manager, Regulatory Compliance
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Avista appreciates the opportunity to provide comments regarding the Staff's Proposed Guidelines to the Integrated Resource Planning Requirements.

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?*

Avista Response: Avista suggests that the extent of the "formalilty" of RFPs for natural gas companies be clarified. Natural gas utilities, by the nature of the natural gas market, seek several bids prior to executing commodity purchases. Avista believes that adequate explanation of the process and documentation of the results could be provided to the Commission as appropriate. However, a natural gas IRP filing should be structured differently than that contemplated for the electric industry. A formal RFP process for electric utilities is the subject of a separate proceeding in Docket UM 1182. The Staff proposed guideline below appears to be linked closely to this electric docket. The following edits are intended to provide appropriate clarification.

> *Related guideline*: The utility should identify in the action plan its acquisition strategy for each resource. Gas utilities should either describe in the IRP their ~~proposed~~ bidding ~~process~~ practices for gas supply and transportation~~, whether formal or informal~~ or provide to the Commission a description of its bidding processes following IRP acknowledgment. Electric utilities should identify those resources that will be acquired through competitive bidding and indicate if they plan to have a utility resource considered in that process, whether utility-built or built by a third party and transferred to utility ownership. ~~For all utilities, the~~ This competitive bidding process should follow IRP acknowledgment. The cost and risk decision criteria for selecting electric resources in the bidding process should be consistent with the decision criteria for selecting resources in the acknowledged electric IRP.

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?*

- To address risk, the utility should at a minimum:

– 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.

Avista Response: Avista seeks clarification of what global warming analysis means to a natural gas utility's IRP process. The Staff has proposed elsewhere in its guidelines that "Utilities should identify in the plan any additional sources of uncertainty" and "Utilities also must consider all costs with a reasonable likelihood of being included in rates over the long term." These two guidelines suggest that global warming would be addressed, by natural gas utilities, in those areas. A separate culling out of global warming for natural gas utilities as specified by staff's proposed guidelines suggests a much greater analysis of global warming. Avista is not clear what is contemplated by the Staff suggestions for "costs and risks for the resource portfolios…as well as risk mitigation strategies" as they relate to natural gas utilities.

Issue 2(c) *How often should utilities update action plans?*

Avista Response: The effect of the Staff proposal for annual updates essentially creates a yearly IRP filing, which the Company opposes for cost and redundancy reasons. It was the Company's understanding, perhaps erroneously, that the concept for an out-of-cycle (or annual) update was totally linked to a proposal in the technical workshop to change the filing cycle of IRPs from two years to three years or more. The *quid pro quo* for a longer filing cycle was to have annual updates. If the Commission keeps the current two-year cycle, as proposed by Staff's guidelines, there would be no need for a required annual update. Under current Commission rules, utilities have the authority to voluntarily provide an out-of-cycle update. Avista provided such an update to the Washington Commission on its electric IRP in 2000 to reflect an updated load and resource situation.

Further complicating the proposed annual update is timing. The update would occur in the midst of the next planning cycle and would detract from planning efforts. Staff, being engaged in the next planning process, would have access to the information requested in its related guideline.

Further, a utility request for an action that is not part of its most-recently acknowledged IRP bears the burden for supporting its request. To require this as part of an annual update moves the IRP closer to a ratemaking document rather than a planning document.

Avista believes that the proposed annual update should be rejected unless the length of the IRP planning cycle is increased from the current two-year process.

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

Avista Response: Avista is concerned that the proposed six-month period for Commission staff and parties comments disadvantages the next IRP planning cycle. The practical effect of this suggestion is that an IRP acknowledgment letter would not be available for, likely, eight months after submission of the IRP. This presumes that no further work is required on the filed IRP; further work could add several months more to the process.

In recognition that Staff and parties are active participants in the IRP process, Avista proposes that comments be due within three months of IRP submittal. Alternatively, the guidelines could specify that such a deadline be a negotiated time period that would take into account the unique characteristics of a given utility's planning process. Yet another alternative would have a draft IRP filed for comments two months prior to the scheduled due date. This would allow time for parties to either provide suggestions or allow for an "advance look" at the final document, thereby increasing parties' "processing time" for comments. Edits to this effect follow.

> *Related guidelines*:
> Commission staff and parties should complete their comments and recommendations within ~~six~~ three months of IRP filing.

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?*

Avista Response: The Staff's proposed guideline for multi-state utilities is reasonable as written. However, the accompanying Staff explanation is problematic. The two paragraphs following this guideline reaches into analysis of other states' IRP processing which is beyond the scope of the Oregon Commission. For example, the Staff states: "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."

If the requirements of another state differ from Oregon, and if those requirements would not impose any difference in cost to Oregon customers, then Oregon should be indifferent to how another state examines an issue. By way of illustration, if another jurisdiction shows a need for additional capacity (with such capacity involving no cost to Oregon customers) during the planning horizon, and if that jurisdiction does not require that a means of satisfying the capacity shortfall be included, then the IRP should not be required by Oregon to satisfy the shortfall. The following edit is intended to recognize this principle.

> *Related guideline:* Multi-state utilities should plan their generation and transmission systems, or gas supply and delivery, on an integrated system basis for common costs that achieves a least-cost/least-risk resource portfolio for all their retail customers.

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

Avista Response: Gas utilities do not plan for industrial customers to return to firm sales customers. If a transport customer wishes to return to sales, they are treated as a new customer and would pay for any and all incremental charges, these primarily being the ability to serve this customer on a firm basis. The Company notes this distinction because this issue appears to be more relevant to the electric industry and excluding the natural gas industry would have no consequences.

> *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.
>
> 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.

Other Issues

(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….

Avista Response: Avista suggests that the Commission recognize that "least cost" should be balanced with "appropriate risk" as the Staff notes in other portions of its guidelines. This would necessitate a change in the above language.

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?*

Avista Response: The Staff states, "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." Avista suggests that "incremental cost" and "marginal cost" be defined. By some standards, these terms are used interchangeably with the same meaning. Further, when additional gas transportation is required from an interstate pipeline, the cost of the transportation is incrementally priced under FERC quidelines. This incremental cost should be assigned to the jurisdiction that has the requirement for the additional transportation.

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

1. The plan must meet four substantive requirements:

   One, all resources[2] must be evaluated on a consistent and comparable basis.
   - All known resources for meeting the utility's load must be considered, including supply-side options which focus on the generation, purchase and transmission of power – or gas purchasing and transportation – and demand-side options which focus on conservation and demand response.
   - Utilities should compare resource fuel types, technologies, lead times, in-service dates, durations and locations in portfolio risk modeling.
   - Consistent assumptions and methods should be used for evaluation of all resources.
   - The real after-tax marginal weighted-average cost of capital should be used to discount all future resource costs.
   - Utilities should analyze how their preferred portfolio would change over a range of reasonable discount rates.

   Two, uncertainty must be considered.
   - At a minimum, utilities should address the following sources of uncertainty:
     – Electric utility plans should address load requirements, hydroelectric generation, plant forced outages, natural gas prices and electricity prices.
     – Natural gas utility plans should address 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.

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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 and demand-side options which focus on conservation and demand response. For natural gas facilities, that includes gas supply purchases, transportation and storage facilities and demand-side options which focus on conservation and demand response.

- 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:
  - 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 three 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.
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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 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)

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

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

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

If the Energy Trust or other entity acquires conservation on behalf of the utility's Oregon customers, the utility should incorporate the entity's conservation projections in resource planning. Further, both should work cooperatively on the 20-year conservation assessments for the utility's service area, as well as joint load management opportunities. Such assessments should incorporate the utility's load research data as well as its knowledge of energy usage trends by customer type.
(Issues 12 and 13)

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

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

10. The utility's load-resource balance should reflect customer loads to be served by an alternative electricity 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 for common costs that achieves a least-cost/least-risk resource portfolio for all their retail customers. (Issue 8)

12. Potential ratemaking treatment should not affect the selection of the least-cost/least-risk portfolio. The utility should advise the Commission during the planning process if it does not have reasonable incentives to acquire a resource that is part of that portfolio. (Issues 1d and 22)

13. To address reliability:
    - Electric utilities should analyze planning margin within the risk modeling of the actual portfolios being considered. The analysis should include varying loads, forced outages, hydro availability, and fuel and market prices and should allow for market purchases within transmission constraints. Loss of load probability and expected unserved energy should be evaluated by year and by future.
    - Natural gas utilities should analyze on an integrated basis gas supply, transportation, and storage, along with demand-side resources, to reliably meet peak, swing and base-load system requirements.
    - The plan should demonstrate that the utility's chosen portfolio achieves its stated reliability, cost and risk objectives.
    (Issue 21)

14. 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 either describe in the IRP their proposed bidding practices for gas supply and transportation, or provide to the Commission a description of its bidding processes following IRP acknowledgment. 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. The competitive bidding process should follow IRP acknowledgment. The cost and risk decision criteria for selecting electric resources in the bidding process should be consistent with the decision criteria for selecting electric resources in the acknowledged IRP. (Issues 1c and 16)

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served Avista Utilities', a division of Avista Corp, comments regarding Staff's Initial Responses to the Integrated Resource Planning Requirements in Docket UM1056, upon the parties listed below by sending a copy via electronic mail.

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I declare under penalty of perjury that the foregoing is true and correct.

Dated at Spokane, Washington this 30th day of September 2005.

____

Linda Gervais
Rate Analyst