September 30, 2005

Via Electronic Filing and U.S. Mail

Oregon Public Utility Commission
Attention: Filing Center
PO Box 2148
Salem OR 97308-2148

Re: In the Matter of An Investigation into Least Cost Planning Requirements
OPUC Docket No. UM 1056

Dear Filing Center:

Enclosed for filing in the above-captioned docket are Portland General Electric's Reply Comments. This document is being filed by electronic mail with the Filing Center.

An extra copy of this cover letter is enclosed. Please date stamp the extra copy and return it to me in the envelope provided.

Thank you in advance for your assistance.

Sincerely,

/s/ V. Denise Saunders by DCT

VDS:am

cc: UM 1056 Service List

Enclosure

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1056

In the Matter of An Investigation into Least Cost Planning Requirements	)))	REPLY COMMENTS OF PORTLAND GENERAL ELECTRIC COMPANY

I. Introduction

Portland General Electric Company ("PGE") appreciates this opportunity to provide reply comments in this docket to update the original Integrated Resource Planning ("IRP") order. We agree with the Commission's observation that the current process generally works. We also agree with the observation of Industrial Customers of Northwest Utilities ("ICNU") that "significant changes in the IRP process do not appear to be warranted" and that modifications generally should be limited to accommodating those laws and regulatory policies that have changed in the intervening years.

Thus, PGE believes the most productive and transparent approach to refreshing the original order is to provide proposed edits directly to the language of that order, as PGE has done in its opening comments. However, recognizing the need for a common format to ease comparison of the numerous detailed proposals of the parties, PGE also provides a side-by-side comparison of Staff's proposed guidelines versus PGE's alternative guidelines as Exhibit A to these comments.[1] We want to emphasize that PGE is largely in agreement with Staff on the basic objectives and goals of IRP. We have indicated in our comparison where some of Staff's detailed guidelines are removed entirely. This is not necessarily because we disagree with the

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[1] We note that Staff's Guidelines do not address issues such as the definition of IRP, the reason for adopting IRP, and the role of the Commission. These were addressed in the original order, and PGE has provided a discussion of these concepts in its opening comments.

concepts that Staff is proposing, rather it is because we believe that the level of detail proposed by Staff will unduly hamper the IRP process. For the most part, PGE's side-by-side comparison simplifies and allows for a less prescriptive process to reach the IRP objectives. We think it is very important to choose flexible guidelines over rigid requirements.

Because Staff's proposal was addressed by PGE both in its own opening comments and in PacifiCorp's comments which PGE generally supports, we do not plow that ground again here. Furthermore, we feel the side-by-side comparison largely speaks for itself and further explanatory comments would be redundant. Following are a few specific comments about the generic UM 1056 process, followed by limited response comments to opening comments filed by other parties to this docket. Our intent is to be as brief as possible while conveying our position on material issues.

II. Comments about the Generic UM 1056 Process

A. Administrative Rules vs. OPUC Order

At the September 23, 2005 workshop, the Administrative Law Judge asked the parties to discuss in their Reply Comments whether some elements of IRP should be codified into the Oregon Administrative Rules. It is PGE's view that none of the resource planning objectives and guidelines need to be included in rules.[2] The original Order has served us well over the past 16 years without need to resort to detailed administrative rules. "Rule" is defined by the Oregon Administrative Procedures Act as "any agency directive, standard, regulation or statement *of general applicability* that implements, interprets or prescribes law or policy, or describes the procedure or practice requirements of any agency." ORS 183.310(9) (*emphasis added)*. The investigation into this matter has shown that a generally applicable, "one size fits all" approach

[2] To the extent that the Commission does adopt any rules, they should allow for the Commission to clarify or waive the rules if needed.

will not work for IRP. IRP objectives and guidelines need to accommodate the unique aspects of gas utilities, electric utilities and multi-state utilities. They need to be flexible enough to address a wide variety of resource acquisition scenarios and to accommodate future progress in the development of planning tools and models.

The adoption of rules would require the Commission to dedicate time and resources to a rulemaking process for which there is simply no need. At the end of the day, if a utility chooses not to follow an IRP guideline issued by the Commission, the utility risks not obtaining Commission acknowledgement of a resource action or plan and the ratemaking and other consequences that follow from such a result. This is the ultimate incentive for a utility to follow the Commission's direction. A prescriptive approach to IRP that limits the flexibility of the Commission and the parties is unwise and unnecessary.

B. Treatment of Externalities

We note the opposing positions of ICNU and of the Citizens' Utility Board in conjunction with Renewable Northwest Project and the Northwest Energy Coalition (hereinafter, "CUB") on this topic, particularly with respect to carbon risk, which tends to dominate uncertainties associated with other emissions and pollutants. PGE believes that it is very important to consider externalities in the IRP process. A utility should incorporate into its planning decisions all information on externalities known at the time these decisions are made. It is important to note that information known about externalities is likely to change from IRP to IRP as new legislation is proposed and enacted and other developments occur. Therefore, a flexible, rather than prescriptive, approach is needed to incorporate information which will change over time.

C. Flexibility of IRP to RFP

PGE agrees with ICNU's observation that the IRP action plan itself should not be so prescriptive as to preclude subsequent course corrections for changing circumstances. Indeed, at times, the Request for Proposals ("RFP") serves to inform the IRP. PGE agrees that IRPs precede and provide direction to RFPs, but wishes to maintain flexibility to deviate from its action plan based on RFP results where it makes sense to do so.

D. Clarifications of PGE's Proposal

Staff has asked for clarification of what PGE meant on page 3 of our Opening Comments under the definition of IRP by the term "commercialized" in "consideration of all *commercialized* resources" (where "commercialized" was substituted for "known"). Perhaps a better wording would be "consideration of all commercially or near-commercially viable resources". Our only intent was to not be unduly inclusive.

Staff has also asked whether we intended to continue to incorporate the directives from Order 93-695 in our proposed planning conventions as set forth on pages 10 and 11, items (5) and (8) of our Opening Comments. We do so intend and cite the Order specifically in item (5a). To add clarity, the conventions in item (5) have to do with evaluating individual resources, whereas item (8) refers to the subsequent portfolio analysis. Providing a range of potential CO_2 cost adders to the individual plants thus provides a basis to test how such plants perform in a portfolio.

E. Planning for ESS-Eligible Customers

It is PGE's understanding that the Commission has requested that reply comments address the questions of whether and how utilities should plan for load that might be served by Energy Service Suppliers ("ESSs"). We believe that utilities should not acquire long-term resources to serve load expected to go to ESS service. Therefore, the IRP process should include estimates of load that will be served by ESSs. These estimates should be based on both past experience and expected future changes. In PGE's case, our estimates would take into account our past experience with Schedule 483 participation.

F. Demand Response via Rate Design

In its initial comments, Staff proposed that rate design should be treated as a potential demand response resource. At the workshop, Staff clarified that the use of rate design as a demand response resource should be voluntary. PGE does not oppose Staff's proposal so long as it is voluntary. However, we note that, as with our current Demand Buy-Back tariff, customer participation in such voluntary programs varies based on prevailing market prices and as a result cannot provide a firm basis for planning. We believe that this is an example of where the IRP guidelines should be general enough to encompass the use of rate design resources but should not be so prescriptive as to require them when they do not make sense.

III. Responses to Opening Comments of Other Parties

A. Response to Idaho Power Comments

We agree with Idaho Power that the IRP should remain flexible enough to allow Idaho to have "continued compatibility in IRP filing requirements between the two states." This goal should be accomplished by making the objectives and guidelines sufficiently inclusive for all electric utilities such that Idaho need not resort to exceptions language for itself.

B. Response to Avista Comments

PGE agrees with Avista that a (maximum) three-year IRP cycle will be more effective. For PGE, a three-year cycle better mirrors our rate of load growth and the "lumpy" nature of major new generating plant decisions. PGE also agrees that many distinctions exist in IRP for electric utilities versus gas utilities. Short of writing two Orders, or two sections within the same Order, this reinforces why detailed prescription is not an effective means to address the unique attributes of gas and electric utilities.

C. Response to NIPPC Comments

Many of the Northwest Independent Power Producers Coalition's ("NIPPC") comments concern congruence between the refreshed RFP guidelines being addressed in Docket UM 1182 and in this docket. PGE is in substantial agreement with NIPPC, PacifiCorp, and Staff on the principles in Docket UM 1182. To the extent that those principles overlap with principles in Docket UM 1056, they should be treated consistently in both dockets.

D. Response to CUB, et al.

- We address treatment of externalities above.
- PGE agrees that, absent a showing of cause, there should be congruence between the IRP action plan and subsequent execution of that plan. As a practical matter, however, this underscores why it is difficult to draw a bright line between the planning function in an IRP and the procurement function.
- PGE agrees that artificial limits should not exist for any given resource type.
- PGE agrees that more robust transmission analysis is needed and we will undertake such analyses in future IRPs to the extent feasible under existing federal, state and regional constraints.
- PGE agrees that any consideration of a utility self-build alternative should be included in an IRP, including the site where the utility has site control. PGE believes that utilities should have the same opportunity as other bidders to keep

the transmission strategies for their self-build alternatives blinded from other bidders.

While PGE agrees in concept with most comments made by CUB, et al, we again caution that these are principles or conventions that we should all look to as evidence of a robust planning process, but the process itself should not prescribe methods.

E. Response to ICNU

We agree with many of ICNU's comments. Specifically, we agree that wholesale changes to the IRP process are not warranted. We also agree that externalities can not be treated based on speculation of when and what future may take place.

III. Conclusion

PGE urges the Commission to maintain the proven IRP formula in Order 89-507 and preserve its flexibility by issuing an Order which simply updates the existing IRP guidelines to account for issues that have arisen and experience that we have gained in the intervening years.

DATED this 30th day of September, 2005.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that I have this day caused the foregoing REPLY COMMENTS OF PORTLAND GENERAL ELECTRIC to be served by electronic and U.S. Mail upon each party on the following official service list in this proceeding:

Dated this 30th day of September, 2005.

/s/Douglas C. Tingey
Douglas C. Tingey

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UM 1056
Section-by-section Comparison
Between OPUC Staff Proposed Guidelines
and PGE Proposed Guidelines

	Staff Proposed Language	PGE Proposed Language
	Substantive Elements:	
1	1. The plan must meet four substantive requirements:	The plan should include the following four substantial elements:
2	One, all resources must be evaluated on a consistent and comparable basis. • All known resources for meeting the utility's load must be considered, including supply-side options which focus on the generation, purchase and transmission of power – or gas purchasing and transportation – and demand-side options which focus on conservation and demand response. • Utilities should compare resource fuel types, technologies, lead times, inservice 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.	Assess on a consistent basis the expected costs of all commercially or near- commercially viable resources available at the time of the decision. 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 Proposed Language	PGE Proposed Language
3	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.	Consider how both risk and uncertainty can affect the preferred portfolio decision.

	Staff Proposed Language	PGE Proposed Language
4	Three, the primary goal must be the selection of a mix of resources with the best combination of expected costs and risks for the utility and its ratepayers. • The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities also must consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource. • Utilities should use present value of revenue requirements (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs for all long-lived resources such as power plants, gas storage facilities, and pipelines as well as short-lived resources such as gas supply and short-term power purchases. • To address risk, the utility should at a minimum: • 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.	Explain how and why the resource portfolio selected yields the best combination of expected costs and associated risks and uncertainties.
5	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)	Demonstrate how the resource portfolio is consistent with the long-run public interest as expressed in state of Oregon and federal energy policies.

	Staff Proposed Language	PGE Proposed Language
	Procedural Requirements:	
6	2. The utility must meet these procedural requirements:	The utility should meet these procedural requirements:
7	• 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 public and other utilities should be allowed significant involvement in the preparation of the plan. That participation must include opportunities to contribute information and ideas as well as to receive information. It must also include the opportunity to make relevant inquiries of the utility formulating the plan. 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.
8	• 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)	Competitive secrets must be protected, either through the procedures presently used by the Commission, such as protective orders, or through aggregation or shielding of data, or some other mechanism.
9	• 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.	Prior to filing of the IRP, utilities and participants should follow the schedule that best meets the needs for interaction and plan development.
	Plan Filing, Review and Updates	
10	3. Plan filing, review and updates will follow this schedule:	Plan filing, review and updates should follow this schedule:

	Staff Proposed Language	PGE Proposed Language
11	• 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.	Utilities should engage in IRP and file a proposed Action Plan and supporting documentation as often as necessary to assure that the process and substance of IRP underlie major resource decisions. Utilities should file a new IRP no later than three years after acknowledgement of the prior IRP.
12	• The utility should present the results of its filed plan at a Commission public meeting prior to the deadline for written public comment.	Once a utility files its IRP and proposed Action Plan, the Commission will engage in a formal review process, including written and oral comments. This will include a presentation by the utility of its plan at a public meeting prior to the deadline for written public comment.
13	• Commission staff and parties should complete their comments and recommendations within six months of IRP filing.	In general, Commission Staff and interested parties should complete their review within six months of the IRP's filing.
14	• 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 consider acknowledgement at a public meeting. If the Commission finds that an IRP requires further work before acknowledgement can occur, it will so indicate to the utility. This process should ultimately lead to acknowledgement.
15	• 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.	<remove entirely>

	Staff Proposed Language	PGE Proposed Language
16	• Each year the utility must submit an update for its most recently acknowledged plan. The update is due on or before the IRP filing anniversary date. The update is an informational filing that provides an assessment of what has changed since acknowledgment that affects the action plan including such conditions as loads, expiration of resource contracts, supply-side and demand-side resource acquisitions and resource costs. The update should explain any deviations from the acknowledged action plan such as actual conservation savings vs. targeted savings. The utility will summarize the update at a Commission public meeting. (Issues 1a and 7, 2b, c and d)	The utility must file a status report annually by the anniversary date of an acknowledged IRP, until that IRP is displaced by a subsequent new IRP filing. A status report should include an assessment of what has changed since the IRP filing, actions taken under the IRP, and deviations from the proposed or acknowledged Action Plan, including any deviations necessitated by unanticipated RFP results.
	Planning Conventions	
17	4. At a minimum, the plan should include the following elements:	In preparing an IRP, the following planning conventions should be used unless a proponent establishes that it makes more sense, given the purpose of IRP, to do something different.
18	• 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	• Use a planning horizon of at least 20 years, with end effects. • Prepare a 20-year load forecast. Identify major drivers of the load forecast and risks and uncertainties related to those drivers. For purposes of the IRP forecast, develop and plan to serve with short-term resources an assumed amount for customer loads that the utility expects may be served by an alternative electricity or natural gas supplier over the planning horizon, or propose an alternative approach. • Prepare a 20-year forecast of capacity and energy available from existing resources. Identify the major assumptions used in this forecast and risks and uncertainties related to those assumptions.

	Staff Proposed Language	PGE Proposed Language
19	• 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	PGE has no comment on this section.

	Staff Proposed Language	PGE Proposed Language
20	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	• 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. • Construct a representative set of resource portfolios to compare present value of revenue requirements (PVRR) and test that PVRR under scenarios of risks and uncertainties most relevant to the period and resource mix under consideration. Scenarios should include a range of cost adders for those environmental requirements or cap-and-trade programs that may reasonably become internal costs over the life of the resources where the impact may be material enough to affect resource selection. Select a portfolio that represents the best combination of expected cost and associated risks and uncertainties for the utility and customers, including the variability of cost outcomes and the severity of potential outcomes.

	Staff Proposed Language	PGE Proposed Language
21	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)	• Assess the costs and specify the attributes of all individual resources considered in the plan, whether short- or long-term. - Costs include all those, such as regulatory compliance (pollution damage and/or mitigation) with carbon dioxide emissions, with a reasonable likelihood of occurring over the long term, covering at least the life of the resource. Utilities also should analyze the range of potential CO_2 regulatory costs in Order No. 93-695, from zero to $40 (1990$). Sensitivity analyses are no longer required for total suspended particulates. - Costs may additionally include fuel transportation and electric transmission necessary to obtain supply delivered to the utility's service territory. - Attributes include operating characteristics, fuel, technology, safety, lead-time, life span, and general location. - Study periodically the conservation and demand response potential for each utility's entire service territory and use the results to forecast availability of these resources for the portfolio modeling. - Identify the major cost and attribute assumptions used in the assessment and the risks and uncertainties associated with those assumptions. - Where applicable and quantifiable, assess any expected cost savings associated with a given resource not otherwise included in the direct cost estimates for that resource. - Include the cost effects of technological advancements. • Discount all future resource costs by the after-tax incremental weighted-average cost of capital.

	Staff Proposed Language	PGE Proposed Language
22	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)	Review regional transmission plans and assess the availability of transmission rights to access resource choices. Explain the effect of transmission availability on resources under consideration in the plan. Consider the effect of fuel transportation and electric transmission system additions on the availability and costs of incremental resources considered in the planning process.

	Staff Proposed Language	PGE Proposed Language
23	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)	<remove entirely>

	Staff Proposed Language	PGE Proposed Language
24	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)	Express energy efficiency and demand-side resources as annual savings targets.
25	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)	<addressed above>
26	10. The utility's load-resource balance should reflect customer loads to be served by an alternative electricity or natural gas supplier over the planning horizon. (Issue 17)	<remove entirely>

	Staff Proposed Language	PGE Proposed Language
27	11. Multi-state utilities should plan their generation and transmission systems, or gas supply and delivery, on an integrated system basis that achieves a leastcost/ least-risk resource portfolio for all their retail customers. (Issue 8)	Multi-state utilities should plan their generation and transmission systems, or gas supply and delivery, on an integrated system basis that achieves the best combination of expected costs and associated risks and uncertainties for all their retail customers.
28	<no language>	Identify and explain any inconsistencies between the selected portfolio and state and federal energy policies.
29	12. Potential ratemaking treatment should not affect the selection of the leastcost/ 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)	Identify and explain any potential barriers to implementation of the selected Action Plan. The regulatory framework and current Commission policies and practices should not discourage the selection of resources that achieve the best combination of cost and associated risk and uncertainty. Utilities should include in the IRP reasoning and analysis regarding any ways in which regulatory policies and practices do not support the resources it would otherwise select.
30	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)	<remove entirely>

	Staff Proposed Language	PGE Proposed Language
31	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)	<remove entirely>
32	15. The utility should identify in the action plan its acquisition strategy for each resource. Gas utilities should describe in the IRP their proposed bidding process for gas supply and transportation, whether formal or informal. Electric utilities should identify those resources that will be acquired through competitive bidding and indicate if they plan to have a utility resource considered in that process, whether utility-built or built by a third party and transferred to utility ownership. For all utilities, the competitive bidding process should follow IRP acknowledgment. The cost and risk decision criteria for selecting resources in the bidding process should be consistent with the decision criteria for selecting resources in the acknowledged IRP. (Issues 1c and 16)	Prepare an Action Plan with resource activities the utility intends to undertake to acquire the identified resources, regardless of whether the activity was acknowledged in a previous IRP. Competitive bidding issues should be handled in accordance with the Commission's determinations in Docket UM 1182.