**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON
LC 43**

In the Matter of PORTLAND GENERAL ELECTRIC 2007 Integrated Resource Plan.	STAFF'S INITIAL COMMENTS AND RECOMMENDATIONS

Following are Staff's initial comments and recommendations on Portland General Electric's (PGE or company) 2007 Integrated Resource Plan (IRP), organized according to guidelines the Commission adopted in Order No. 07-002.[1] Attachment A consists of PGE's response to Staff's comments on the draft IRP. Attachment B consists of PGE's responses to selected data requests.

Before issuing final comments, recommendations and a proposed order, Staff will further review the company's filed plan, responses to recent data requests and parties' comments.

I. General Issues

1) Staff and PGE continue to disagree that this IRP meets the Commission requirements for a twenty year planning horizon and consideration of all resource options. In PGE's response to Staff's related comments on the draft IRP, the company countered that "The goal of an IRP should be to better inform an RFP."[2] This perspective is the company's justification for only considering in the IRP technologies that are commercially available in the timeframe of the next RFP. Previously, in comments in Docket UM 1056, PGE recommended that the IRP process require only consideration of "all commercially or near-commercially viable resources," rather than consideration of all "known" resources. *See* PGE Reply Comments in Docket UM 1056 at 4. The Commission did not agree with the company's opinion and stated that the IRP should include all resources "that are expected to become available," not just those currently available. *See* Order No. 07-002 at 4.

Regarding the 20-year planning horizon, PGE believes it has met the substantive requirement of the IRP order but only adds resources in 2012. The company states that there is too much uncertainty in future technologies to make assumptions other than market purchases beyond 2012. This is another area where the company bases its actions on the belief that the purpose of the IRP is to inform an RFP. Staff disagrees. From guideline 1c:

> *The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities should consider*

[1] As corrected by Order No. 07-047.
[2] *See* Attachment A at 2 under the planning horizon discussion.

> *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.*

PGE's treatment of the planning horizon in this IRP provides no analysis of the likely circumstance that the company must acquire or build resources beyond 2012. The company has stated there is too much uncertainty about future technologies, regulations and costs to consider adding resources beyond the self-identified "watershed" year of 2012. As a result of this approach, PGE's IRP and action plan does not fully meet the Commission's IRP guidelines. Instead, the IRP lays out a relatively non-controversial set of actions to be implemented until the next IRP cycle. The company expects many of the technologies and regulatory policies to mature prior to submitting the next IRP. Whether or not the answers are forthcoming in that timeframe, what is essentially a four-year plan does not meet a threshold Commission goal of long-term planning.

2) Staff assumes it was the Commission's intent that utilities use the various IRP guidelines to make decisions in the public interest. In this IRP, the company does not clearly demonstrate how it combines the components of the analysis (cost and risk) to decide on a preferred portfolio. The company refers to the "flexibility" of a particular portfolio, and this appears to be a significant attribute to the company. Yet the IRP provides no quantification or ranking of flexibility. In Chapter 11, the company compares the different portfolios for a variety of metrics but it's not clear what weighting those metrics have in the ultimate evaluation.

Instead of allowing the IRP analysis to fully drive to a preferred portfolio, it appears the company made a business decision on a preferred portfolio that is not controversial and gives the company until the next IRP cycle for many of the policy, regulatory and technological questions to be answered. To address this issue, Staff recommends the following addition to PGE's 2007 IRP Action Plan:

> *In the next planning cycle, complete the portfolio analysis by presenting a rank ordering of the portfolios that considers all of the factors (costs, risks and uncertainties) used to select its preferred portfolio.*

Renewable Northwest Project (RNP) has been the only party to file comments on PGE's IRP. Other than RNP's concerns which are discussed below, there has been little public comment or concern with the company's IRP and proposed action plan. Based on comments other parties expressed in workshops, this is primarily because the preferred portfolio includes no baseload fossil fuel or nuclear resources.[3] Even so, Staff cannot call this a long-term, integrated resource plan. Instead, it is a short-term plan that buys PGE time.

II. Review of the Plan Based on the Commission's IRP Guidelines

[3] The Action Plan includes a gas-fired peaking plant.

Below Staff provides its assessment of whether PGE's 2007 IRP meets each of the Commission's guidelines for resource planning. In so doing, Staff recommends whether the company's action plan should be modified, including direction for the next planning cycle pursuant to guideline 3e.

Guideline 1: Substantive Requirements

a. *All resources 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 … and demand-side options which focus on conservation and demand response.*

  Staff discusses under General Issues concerns about the company not including all known resources in this IRP. Staff agrees with RNP that the company should more thoroughly evaluate both generation and direct use applications for solar energy resources.[4] Both Staff and RNP praise the company for including biomass and geothermal when they modeled renewable resources in the portfolios. In addition, the company did not include any nuclear resources in its analysis.

- *Utilities should compare different resource fuel types, technologies, lead times, in-service dates, durations and locations in portfolio risk modeling.*

  Staff finds that the company has not met this requirement. While the action plan does include differing durations and in-service dates for resources, the company did not consider anything other than market purchases as a way to meet load growth beyond 2012.

- *Consistent assumptions and methods should be used for evaluation of all resources.*

  Staff agrees with the company's assessment that it met this requirement.

- *The after-tax marginal weighted-average cost of capital (WACC) should be used to discount all future resource costs.*

  The company applied its after-tax WACC of 7.59 percent to discount all cost streams.

Following are Staff's assessments by resource category:

[4] As RNP points out, the analysis should reflect the expected cost of solar energy measures to the company – that is, after subsidies and customer contributions have been taken into account.

Demand-Side Management. The company includes all of the achievable cost effective conservation in its energy analysis. In its analysis of capacity needs, the company includes dispatchable standby generation (DSG), direct load control and critical peak pricing. Staff provides detailed comments under Guidelines 6 and 7.

Renewable Resources. The company modeled wind, biomass and geothermal resources. PGE contracted with EnerNex in February of 2007 to perform a wind integration study. For various reasons (*see* PGE's response to Staff Data Request No. 7), EnerNex did not complete the study prior to the IRP and still has not completed the study at the time of these comments. In lieu of the completed study, PGE used an integration cost of $6/MWh for Tier 1 wind and $10/MWh for Tier 2 wind which the company states is consistent with analysis by the Northwest Power and Conservation Council.[5] RNP objected stating "$10/MWh is higher than the high end of the Council's reported range and is inconsistent with other analyses done around the region." The company stands by the values used in this IRP. In addition, PGE performed sensitivity studies and concluded that in the range of $6.00/MWh to $14.00/MWh, there is no change to the company's proposed action plan.

Integration costs are a concern for Oregon, and the region, as wind is considered to be one of the least costly ways to meet the requirements of the state's renewable portfolio standard (RPS). Lacking an integration study, the company risks over or under estimating the most cost-effective amount of wind to incorporate in its portfolio of renewable resources.

Staff recommends the following addition to PGE's 2007 IRP Action Plan to address this issue:

> *In the next planning cycle, include in the analysis a timely wind integration study that has been vetted by key regional stakeholders.*

Market Purchases. All 13 portfolios the company considered contain approximately 180 aMW of short- and mid-term market purchases. PGE states this is necessary because commercial and industrial customers have the option of choosing an alternative energy service supplier with one year notice. *See* IRP at 169. Long-term power purchase agreements (PPAs) were included in two of the considered portfolios. In this IRP, PGE changed the Beaver plant from an energy resource to a capacity resource in order to allow economic dispatch of the facility during peak demand. The intent is to protect ratepayers from high spot market purchases.

Distributed Generation. The company included 80 MW of dispatchable standby generation its analysis. PGE considers DSG a key component of its portfolio.

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[5] PGE evaluated wind on two tiers for expected capital costs and capacity factors. Tier I is expansion of PGE's Biglow Canyon Project and Tier II includes all other wind resources. *See* IRP at 104.

PGE did not include combined heat and power (CHP) as a resource. The company cites several obstacles to successful implementation of CHP projects in their territory but commits to continued exploration of CHP potential. *See* IRP at 123–126.

Fossil-Fuel Resources. The company considered both coal and natural gas in the evaluated portfolios. The coal technologies included supercritical pulverized coal plants without sequestration, integrated gasification combined cycle (IGCC) plants with and without sequestration. Both simple-cycle combustion turbine (SCCT) and combined-cycle combustion turbine (CCCT) gas plants were considered for capacity actions but only CCCT plants were included in portfolios for energy analysis.

Nuclear Resources. PGE did not evaluate any portfolios that included nuclear resources, citing significant public barriers to nuclear technology. The company does expect advanced nuclear technologies to be considered in future IRPs. Staff recommends the following addition to the Action Plan:

> *In the next planning cycle, include nuclear resources as an option for portfolio selection.*

Transmission. PGE modeled the cost of transmission by using BPA's standard transmission tariff rates. PGE also evaluated transmission capacity and determined there is adequate capacity through 2012. Staff addresses the analysis further under Guideline 5.

b. *Risk and uncertainty must be considered.*

- *At a minimum, electric utilities should address the following sources of risk and uncertainty: load requirements, hydroelectric generation, plant forced outages, fuel prices, electricity prices, and costs to comply with any regulation of greenhouse gas emissions.*

  The IRP meets this requirement in principle but not in implementation. See Staff's discussion of PGE's risk analysis under guideline 4l.

- *Utilities should identify in their plans any additional sources of risk and uncertainty.*

  Additional sources of risk and uncertainty identified in the plan are availability of federal tax credits for renewable energy resources, renewable portfolio standards, and what the company has identified as "Scenario Risk" and "Paradigm Risk." *See* Chapter 10, Section 7.

c. *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 customers.*

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

  Staff finds PGE did not comply with this requirement. See the discussion in the General Issues. Staff recommends the following addition to the Action Plan to address this deficiency in the future:

  > *In the next planning cycle, include resources other than market purchases to meet energy needs for at least the first 10 years of the 20-year planning horizon. All resources expected to become available during the resource acquisition period should be considered.*

- *Utilities should use present value of revenue requirement (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 all short-lived resources such as gas supply and short-term power purchases.*

  The IRP complies with this standard. *See* Appendix H.

- *To address risk, the plan should include, at a minimum:*

  1. *Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes.*

     The plan complies with this requirement.

  2. *Discussion of the proposed use and impact on costs and risks of physical and financial hedging.*

     The IRP complies with this requirement. *See* Chapter 12, Section 5 for a discussion of capacity alternatives.

- *The utility should explain in its plan how its resource choices appropriately balance cost and risk.*

  The company discusses its energy analysis in Chapter 11 and its capacity analysis in Chapter 12. These analyses present extensive modeling of both cost and risk metrics. However, the ultimate choice of a preferred portfolio appears to be subjective. The company does not discuss how it quantitatively included the “Other Quantitative Performance Metrics” (*see*

IRP at 197-204) in the analysis. Each additional metric considered is discussed but it is not clear how they are analyzed relative to each other.

d. *The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.*

PGE filed its resource plan only a few weeks after the Oregon Renewable Energy Act (Senate Bill 838) was signed into law. Without regard to the Act, the company's cost/risk analysis supported inclusion of 323 MWa of additional renewable resources in the preferred portfolio by 2012, representing an estimated 16.8% of its load served by renewable resources by 2015. This exceeds the statutory requirement of 15% of load served by renewable resources by 2015.

Mandatory CO_2 regulations are on the horizon as well. House Bill (HB) 3543 (2007 Session) was signed into law after PGE filed its plan. This legislation established a state policy to stop the growth of Oregon greenhouse gas emissions by 2010; cut them 10 percent below 1990 levels by 2020; and reduce them at least 75 percent below 1990 levels by 2050. The legislation did not establish specific mechanisms for achieving these goals. With 36% of the energy action items[6] supplied by renewable resources, PGE's preferred portfolio, positions the company well in light of whatever system or mechanism is ultimately implemented.

Guideline 2: Procedural Requirements

PGE met all procedural requirements.

a. *Public involvement in the preparation of the IRP*

The company provided many opportunities for public input. *See* IRP Chapter 1 and Appendix B.

b. *The plan should include non-confidential information that is relevant to the company's resource evaluation and action plan.*

The company provided non-confidential information in the main IRP document and Appendices, meeting materials, materials posted to their website, via e-mail and in response to data requests.

c. *Draft IRP for public review and comment*

The company provided its draft IRP for public review and comment on June 5, 2007.

[6] The company also plans to undertake roughly 700 MW of capacity supply actions as well.

Guideline 3: Plan Filing, Review, and Updates

a. *Timeliness of IRP filing*

The company filed its 2007 IRP approximately 3 years after acknowledgment of the last plan. In Order No. 05-1138 the Commission directed PGE that its next IRP was due December 2006. In Order 07-002, the Commission extended that due date to second quarter of 2007 so that the company would submit an IRP consistent with the order.

b. *Timely presentation of the results of the filed plan at a Commission public meeting*

The company presented the results of its plan to the Commission at a special public meeting on September 19, 2007.

c.-g. *N/A*

Guideline 4: Plan Components

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

a. *An explanation of how the utility met each of the substantive and procedural requirements*

Appendix A of the IRP provides this explanation.

b. *Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions*

The company tested its portfolios against high (3%) and low (1%) load growth scenarios.

c. *For electric utilities, a 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*

Staff's Analysis of Load Forecasts. Beginning with load growth, this plan indicates expected load growth of 2.2% overall. The IRP states that loads and peaks are rising faster in the summer than winter because of an increase in residential and commercial summer cooling load and flat to falling growth in water and space heating. The summer month peak demand growth is predicted to average 2.7%, versus 1.8% in winter peak demand. This trend is moving

PGE towards becoming a summer peaking utility long term but probably not by 2012. Overall, energy consumption will continue to be greater in the PGE territory in the winter because of the winter heating load, a desirable attribute when the large wholesale customer to the south tends to consume more power in the summer.

Load-Resource Balance. Staff compared the load growth predictions to historic growth figures for the area and to independently produced long term growth forecasts for the region. We find PGE's predicted growth rate of 2.2% not well supported either from a historical perspective or by forecasts from others. The company cites a favorable business environment, gains in productivity and emerging sectors creating new growth, and the continuing strong performance in the high tech sector as support for its robust growth predictions. Other independent reports however, including the Northwest Power and Conservation Council's (NWPCC) "Biennial Monitoring Report on the 5th Power Plan," estimated electricity growth at just less than 1% for the period. The same report presented figures that show a historic electricity growth rate from 2000 to 2005 of 1.4%.

PGE's reliance on short-term power markets for a significant part of its load somewhat reduces Staff's concern about the high forecasted growth rate. However, it is important for the company's load forecasts to be correct not just to facilitate the planning and development cycle for new resources, but also because power cost updates rely on forecasts of load based on the IRP process.

On the supply side the company does not have sufficient generation to supply its entire load and is always buying electricity in the market. Generally the company-owned thermal resources are base loaded; shortfalls are filled in with a combination of long term and short term power purchases. One exception is the Beaver plant, which has a relatively high production cost. Its output is modeled based on economic dispatch. The IRP targets 2012 as the year that the imbalance between load and resources is large enough that "…significant new supply actions are necessary to address the deficit." *See* IRP at 4. At that time the gap between energy supply and load is 818 MW and the capacity needs, assuming overall reserves of 12%, are 1,540 MW in winter and 1,330 MW in summer.

Commodity Prices. The forward price curves for gas and, to a lesser extent, coal drive wholesale electricity market prices. In this IRP, PGE uses near term market indications and a longer term fundamentals pricing model developed by PIRA Energy Group to develop forward natural gas price curves. This methodology is consistent with what previous IRPs have used and found to be acceptable. Long-term coal pricing is based both on the company's existing coal contracts and the Powder River Basin commodity cost forecasts by Hill and Associates, a third-party coal pricing concern. Rail costs for the Boardman plant are included with a reasonable escalation. Staff finds that the electricity and fuel pricing models and methods used are acceptable.

Transmission. The company modeled existing transmission rights that meet its needs through 2012.

d. *N/A*

e. *Identification and estimated costs of all supply-side and demand-side resource options, taking into account anticipated advances in technology*

The company included in its analysis supply-side technologies that are commercially available and cost competitive. *See* IRP, Table 7-2 at 117. The company looked to the NWPCC 5th Power Plan and the 2006 EIA Annual Energy Outlook for projecting anticipated efficiency and cost advances for these technologies.

f. *Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs*

The IRP does not meet this requirement. *See* the discussion under guideline 11.

g. *Identification of key assumptions about the future (e.g., fuel prices and environmental compliance costs) and alternative scenarios considered*

The IRP meets this requirement. The company tested a range of alternative scenarios against its reference case (*see* Chapter 10 at 173-174). The variables included are described in the IRP, at 174-176.

h. *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*

The IRP does not meet this requirement because only market purchases are considered beyond 2012 for meeting load growth.

The company evaluated 13 portfolios. Additional portfolios were evaluated in response to Staff's and RNP's questions about wind integration costs. *See* PGE's response to Staff Data Request No. 7.

i. *Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties.*

The IRP meets this requirement. *See* Chapter 11.

j. *Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results*

The IRP meets this requirement in principle. While the portfolios are ranked by their calculated expected NPVRR under 18 futures (*see* IRP Appendix H), it is not clear how the company considered those rankings along with the other risk factors evaluated to conclude that the Diverse + Contracts portfolio represents the best combination of cost, risk and uncertainty. PGE provides analysis of the performance of the portfolios across different sensitivities and discusses the merits of each individual portfolio but did not provide an analytic path from the various rankings to an overall performance ranking.

k. *Analysis of the uncertainties associated with each portfolio evaluated*

The IRP meets this requirement. *See* Chapter 11.

l. *Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers*

PGE estimated future revenue requirements over a 20-year study period to compare the costs and risks of candidate portfolios. The company considered both stochastic and scenario risks. Stochastic analysis applies when probability distribution functions can be estimated. Such is the case with fuel and electricity market prices, hydro conditions, loads, and thermal plant availabilities. Scenario risks represent the uncertainties regarding major economic structural changes in environmental compliance costs, natural gas prices, and power production technology.

PGE performed five studies in which the "known" scenario elements were altered in a limited number of ways, and three separate stochastic studies. All of the stochastic risk studies were founded on the base case scenario.[7] Perhaps reflecting some confusion regarding the nature of risk and cost-risk trade-off, some studies yielded conflicting results. Other studies were largely redundant.

The first step in the scenario set of evaluations for PGE was to establish the key study period inputs used in the deterministic Reference Case study. Those inputs included commodity fuel prices, transportation costs, PGE loads, etc. A CO_2 tax of $7.72 was also assumed, starting in 2010. The study period net-present-value-revenue-requirement (NPVRR) was then calculated for each of the 13 candidate portfolios. The NPVRR values constituted the principal "costs" that were subsequently matched with "risks" in seeking the preferred cost-risk combination.

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[7] In contrast, PacifiCorp performed separate stochastic risk studies for four CO_2 regulatory compliance scenarios, in addition to stochastic study performed for the base case level.

To explore how the portfolios would perform given circumstances other than the Reference Case set, PGE constructed 13 alternative "Futures"[8] for the study period. Some of the Futures consisted of altering only one element within the Reference Case -- e.g., CO_2 taxes. Other Futures combined deterministic alterations to two elements within the Reference Case. For example, one Future positioned both gas prices and renewable production costs at a level that was 10% above the figures used in the Reference Case. No constructed Future entailed simultaneously altering more than two of the Reference Case elements. This is a concern in light of how high costs might be under the most adverse conditions that are readily pictured.

The first of the three scenario risk studies[9] measured "risk" in terms of the amount by which the projected cost for a portfolio under the worst Future *studied* exceeds its projected costs under Reference Case conditions.[10] Staff faults this risk study on three grounds – all relating to the idea that its risk metric does not capture what might be the upper end of future costs. Staff's first concern stems from the fact that future scenarios are easily imagined that would cause costs to be greater than what were produced by the most grievous Future that PGE *chose to consider* -- i.e., "high gas prices with a $25 per short ton CO_2 tax." For example, it would have been useful to test the portfolios against a $40 or higher CO_2 tax in conjunction with high gas prices.[11] Staff's second concern is that the study does not reveal the effects of probabilistic, adverse excursions in hydro conditions, loads, and fuel and market prices.

Staff's third and most serious concern is with the way "risk" is constructed in this study. The result is that some portfolios receive favorable risk scores despite their having among the highest costs of all the portfolios under every Future considered. Because PGE *subtracts* what might also be a very high NPVRR under Reference Case conditions from NPVRR calculated under the higher-cost, worst-Future conditions, a relatively unattractive portfolio may get a good "risk" score even though both its worst-Future and Reference Case NPVRR are extremely high.[12] That outcome is problematic because what is

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[8] A specific set of modeling inputs/ assumptions regarding the future study period.

[9] *See* IRP at 189-191.

[10] Symbolically, referring to portfolio X: $RISK_X \equiv \{NPVRR_X|\text{Worst Future Studied} - NPVRR_X|\text{Reference Case}\}$.

[11] While a $40 carbon tax was also evaluated, its "Future" involved no other Reference Case element change beyond the CO_2 tax.

[12] Symbolically, where X is a more attractive portfolio than Y -- i.e., X has a lower NPVV under both Reference Case and Worst-Future conditions, *but much lower under Reference Case conditions*:

If $\{NPVRR_X|\text{Worst Future Studied} < NPVVR_Y|\text{Worst Future Studied}\}$
and $\{NPVRR_X|\text{Reference Case} << NPVVR_Y|\text{Reference Case}\}$
then,"contrarily," $RISK_x > RISK_y$
because $\{NPVRR_X|\text{Worst Future Studied} - NPVRR_X|\text{Reference Case}\}$
>

bad for ratepayers (and the utility) is a NPVRR that by itself is high, independent of how much higher it is than some base case figure.

PGE's second scenario risk study captured the more relevant notion of risk that was just described.[13] The company defined this "risk" as the NPVRR under the most adverse Future considered.[14] The two portfolios that had the lowest risk under the first study's definition had under this second study's definition among the highest risk values.[15] This study shared the first two limitations of the previous scenario risk study.

The third PGE scenario risk study was similar to the first.[16] The only difference was that PGE substituted the portfolio's average NPVRR over a number of Futures for the Reference Case NPVRR. The same criticisms apply as with the first study.

The fourth scenario study, "Probability of High Expected Costs," isolated the four or five most costly portfolios under each of the studied Futures.[17] This study is useful insofar as it identified as inferior some portfolios that the first and third studies had shown in a favorable light.

The fifth scenario risk study narrowed the cost definition to the NPVRR of the "new resource additions without existing resources" and again tested the portfolios against all the Futures. Not surprisingly, more adverse Futures led to higher costs, and "diversified and greener portfolios perform more consistently across various futures…."[18] It is useful to understand how portfolios might perform under all kinds of conditions, not just worst-case conditions. The problem with this last study, however, is that performance is a product of the utility's entire set of resources, not just the newly added ones. Depending upon relative operating costs and other factors that determine resource operations over the study period, there can be a lot of interplay between how pre-existing resources perform and the particular mix of new resources.

PGE's three stochastic analyses[19] employ the TailVaR90 risk metric, which is the mean of the worst 10 percent of the NPVRR outcomes for a given portfolio.[20] As described in Staff's Initial Comments and Recommendations

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$$\{NPVRR_Y|\text{Worst Future Studied} - NPVRR_Y|\text{Reference Case}\}.$$

13 This alternative risk metric was "suggested during our public process." *See* IRP at 191-192.

14 Symbolically, $RISK_X \equiv NPVRR_X|\text{Worst Future Studied}$.

15 Only three out of the thirteen portfolios considered had higher risks using this second definition.

16 *See* IRP at 192-193.

17 *See* IRP at 193-194.

18 *See* IRP at 194-195.

19 *See* IRP at 204-208.

20 TailVaR90 stands for the "Value at Risk" at the upper 90 percent tail region.

for PacifiCorp's 2007 IRP, TailVaR90 is an eminently reasonable mechanism for appraising risk.

The first stochastic risk study plotted the portfolio's TailVaR90 for the stochastic iterations of the NPVRR against the stochastic average NPVRR. All the stochastic analyses were conducted using Reference Case nominal figures or near such. The IGCC-with-sequestration portfolio had the highest risk in this study.[21] In contrast with the conclusions drawn from the scenario analyses, the Market and PV Coal portfolios had the most attractive cost-risk outcomes.[22] That is because those two portfolios were not tested in the stochastic context against adverse gas price[23] and carbon tax Futures. Such would have produced worse NPVRR for those two portfolios than for most of the other portfolios. Of considerable interest would have been to know how high the stochastic variable perturbations would have driven costs in an environment with CO_2 taxes substantially above the Reference Case level. Staff concludes that the usefulness of this and the other PGE stochastic risk studies is limited by virtue of their application only to simulated costs factors that were at or near those of the Reference Case.

The second stochastic study was based on the TailVaR90 of variable costs (rather than total costs). "Market," the portfolio that relied least on having the company own its resources, demonstrated the highest risk according to this metric.

The third stochastic study calculated TailVaR90 on the basis of year-to-year rate changes. As expected, portfolios with the greatest share of fixed versus variable costs had the lowest volatility in revenue requirements.

Staff Recommendations Regarding Cost and Risk Analyses: Performing the stochastic risk analyses using only inputs that approximate the Reference Case as their basis limits their usefulness. Similarly, performing scenario risk analyses without considering stochastic risks limits their usefulness. Risk involves both stochastic and scenario concerns and elements that often interact. For example, a portfolio that seems to have a low level of stochastic risk under favorable carbon tax and gas price conditions may have an unacceptably high risk in a less favorable environment. Accordingly, Staff strongly recommends the following addition to the IRP Action Plan:

> *For the next IRP: a) establish a set of CO_2 adder levels that covers the gamut of expected environmental regulatory benchmarks; b) match*

[21] It also had the highest base case average cost.
[22] *See* Figure 11-11, IRP at 206.
[23] Note the two kinds of gas price movements considered in the IRP analyses: a) long term trends due to shifts in demand from coal to gas or to increased domestic scarcity coupled with limitations in liquefied natural gas imports and b) stochastic movements – partly weather related – reflecting historically observed year-to-year price fluctuations about the trend.

projected loads and gas and electric prices that are economically consistent with those CO_2 adder levels; c) perform the stochastic runs for each of those adder levels/matches; and d) define "risk" for each portfolio at each CO_2 adder level as the TailVaR90 corresponding to the stochastic runs associated with that level.[24]

The combined stochastic and scenario risk measures plus the TailVaR90 measure of year-to-year rates volatility are the only risk measures of notable value. As regards portfolio costs, two measures of costs for each CO_2 adder level should be developed. They are the average NPVRR of the stochastic runs, and the deterministic NPVRR value based upon all the CO_2 adder levels' nominal inputs.

m. *Identification and explanation of any inconsistencies of the selected portfolio with any state and federal energy policies that may affect a utility's plan and any barriers to implementation*

   The IRP meets this requirement. The company identifies several policy and regulatory issues that may impact the preferred portfolio. *See* IRP at 246-250. These include the outcome of Docket UM 1276 and how that may affect the power purchase agreements in the preferred portfolio, the continuation of the federal Production Tax Credit for renewable resources, the ability to acquire sites for development of renewable resources, and uncertainty around ratemaking for capacity contracts.

   The IRP was filed before Oregon adopted emissions reduction goals for greenhouse gases (HB 3543). Staff recommends the Commission require the company to develop a scenario to meet the emissions reduction goals in HB 3543:

   For the 2007 IRP update and next planning cycle, develop and fully evaluate a portfolio that reduces the company's CO2 emissions consistent with the goals expressed in Oregon HB 3543

n. *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*

   PGE's energy and capacity action plans are discussed in Chapter 13 of the IRP. This information is also summarized in PGE's response to Staff Data Request No. 5.

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[24] Example: If $40/ton ($2010) is one of the benchmark CO_2 tax level/cap-and-trade equivalent to be tested, first establish the base case levels of loads and gas and electricity prices that are consistent with that adder level; next perform for each candidate portfolio the stochastic runs around the base case levels; finally, determine the TailVaR90 values for each portfolio at that CO_2 adder level.

Guideline 5: Transmission

The IRP meets this guideline, with the exception noted below.

Order No. 04-375 established conditions for acknowledgement of PGE's 2002 IRP Action Plan related to the company taking actions to develop transmission capacity over the Cascades. Specifically, the acknowledgement stipulates that PGE:

> 1) commits to initiating discussions with Staff, renewable developers, BPA, ETO and other stakeholders to discuss constraints to competitive renewable development in the region; 2) agrees to include an action item in its 2005 IRP to address how it will work with BPA and others to develop transmission capacity over the Cascades so that additional resource are accessible to PGE at a reasonable price; and 3) agrees to demonstrate that it has made reasonable efforts to acquire, retain, or option cost effective transmission capacity over the Cascades before issuing its next RFP. *Order No. 04-375 at 12.*

In an IRP update to the Commission in March 2006, PGE stated, "In the area of transmission, PGE has actively participated in several Bonneville Power Administration (BPA) and regional forums and initiatives to explore ways to increase transmission availability across the Cascades. In some cases these efforts have resulted in new BPA business practices and increased transmission capacity. PGE has also taken steps to retain existing transmission rights to protect the reliability interests of our customers."

According to the company's analysis, transmission constraints have the potential to impact PGE in 2012. Approximately three-quarters of PGE's power supply is delivered by BPA. BPA consistently has requests for transmission capacity in excess of what is available. PGE has been able to alleviate some of its transmission needs with Port Westward coming on-line in June 2007. Power from Port Westward can be transmitted to PGE territory without using BPA transmission lines. However, this does not eliminate the need for new transmission. PGE is currently studying the economic feasibility of a potential transmission expansion project (Southern Crossing project). BPA is also partnering with the Northwest Power and Conservation Council on a wind integration action plan.

An additional consideration is the recently issued FERC Order 890, Preventing Undue Discrimination and Preference in Transmission Service. This order requires public utility transmission providers to show how their planning process meets specified transmission planning principles. Filings were due to FERC by

October 11, 2007. The impact of these new planning reforms is unknown at this time.

Staff applauds the company for the analysis it has performed and participation in regional planning. However, the company has identified a transmission need in 2012, but there are no projects in progress. Staff recommends the following addition to the IRP Action Plan to address this issue:

> *In the next IRP Update, include an analysis of when transmission construction projects must begin in order to meet the 2012 need.*

Guideline 6: Conservation

a. Periodic conservation potential study for the entire service territory

Under the Commission's updated planning guidelines, the utility should analyze potential conservation resources regardless of any limits on funding. The IRP presents PGE's assessment based on a study by the Energy Trust of Oregon. The company reviewed the Trust's assumptions, updated it with the company's latest load growth projections, and asked the Northwest Power and Conservation Council and the Trust to review the company's final conclusions.
OAR 860-030-0010(6) requires the utilities to use a 10 percent discount for conservation resources when determining cost-effectiveness. The Commission explicitly recognized that the 10 percent discount accounts for the value of conservation in reducing risk and uncertainty.[25] The Trust and PGE include the 10 percent discount in the assessment presented.

PGE concludes there is 125 aMW of achievable cost-effective conservation through 2012. The Trust has projected that funding provided by the public purpose charge will enable it to acquire 65 aMW, leaving 60 aMW that cannot be achieved without additional funding. SB 838 excludes customers with loads greater than 1 MW from being subject to increased tariffs for incremental energy efficiency acquisition as well as from benefits from that additional funding. Excluding those classes of customers from the remaining achievable potential (therefore removing the energy that could be saved by those customer classes) leaves 45 aMW of additional conservation that could reasonably be targeted for acquisition.

b. N/A

c. To the extent that an outside party administers conservation programs in a utility's service territory at a level of funding that is beyond the utility's control, the utility should:

[25] *See* Order No. 94-590 (UM 551) at 14.

- *Determine the amount of conservation resources in the best cost/risk portfolio without regard to any limits on funding of conservation programs; and*
- *Identify the preferred portfolio and action plan consistent with the outside party's projection of conservation acquisition.*

Staff finds PGE's evaluation of near-term conservation resources appropriate and appreciates the company's approach of requesting additional review by the Council. Staff does not agree with many of the roles the company proposes to play in acquiring the available conservation. This role will be more fully defined through subsequent tariff filings. However, Staff in no way wants to the leave the company with the impression that potential acknowledgement of this IRP indicates approval or agreement with the activities the company proposes.

The company did not provide any analysis of conservation potential beyond 2012. As is the case with all resources other than market purchases, the company did not include in portfolio analysis conservation resources beyond 2012. Therefore, Staff concludes that the company did not meet the requirements of this guideline in its entirety. Staff makes the following recommendation to address this deficiency:

> *In the next IRP, assess conservation potential for at least the first 10 years of the planning horizon. Include conservation resources in portfolio modeling throughout this resource acquisition period, and include best cost/risk conservation resources in the preferred portfolio.*

Guideline 7: Demand Response

The Commission's order on the company's 2002 IRP (Order No. 04-375) states that for the next plan, "…PGE should model dispatchable demand response resources (such as direct load control and demand buybacks) as portfolio options that compete with supply-side options. Further, PGE's load forecasts should recognize the effects of nondispatchable demand response resources (such as time-of-use pricing)."

Staff believes PGE's plan meets these requirements, as well as Guideline 7 in Order No. 07-002. Using its Aurora model, the company evaluated firm demand-side capacity resources such as residential direct load control on par with supply-side capacity resources. Specifically, the company calculated the real levelized capital carrying cost and ongoing O&M for each option, then assessed the transmission and fuel risk to determine which option to use first given the company's load duration curve. *See* IRP at 64. Further, the company evaluated voluntary rate programs such as critical peak pricing (CPP) for small customers and curtailment tariffs for large customers.

PGE states that because load forecasts are based on historical data, they implicitly reflect the effects of the company's time-of-use pricing option. The company also points out that load forecasting is based on historical usage.

PGE's proposed capacity actions include all firm direct load control considered to be achievable, cost-effective potential by 2012 based on third-party estimates and assuming implementation of advanced metering infrastructure (AMI). By 2012, the company believes it can reliably achieve up to 140 MW of incremental resources from customer-based capacity resources with day-of or day-ahead notice. That includes 23 MW (summer) to 25 MW (winter) of direct load control of air conditioning, water heating and space heating for residential and small nonresidential customers. The plan also includes 35 MW of remote curtailment of end-use loads in commercial and industrial facilities and CPP tariffs for small customers. *See* IRP at 12, 65-67.

Regarding implementation dates, PGE planned to file a curtailable tariff for large customers by the end of 2007. In the second quarter of 2008, the company plans to issue a request for proposals for purchase agreements from third-party providers for peak demand-side capacity, then file a tariff pending successful responses. PGE plans to file an experimental CPP tariff approximately first quarter of 2009. *See* Joint Exhibit 101, Docket UE 189, November 21, 2007, pp. 2-4.

Initially, PGE planned to issue an RFP for direct load control to track with its AMI installation. Now, however, the company plans to issue the RFP eight months prior to the scheduled completion of AMI deployment, approximately the first quarter of 2010, with a tariff filed later that year. PGE proposes this timing in order to issue an RFP for direct load control providers that will be attractive to the market – in other words, timed for full use of the AMI system. Staff recommends that the Commission direct PGE to review the appropriate timing for a direct load control program as the company develops its CPP tariff in 2008. At that time, PGE should review future technology needs for direct load control, appliance controls, and pricing programs for residential and small non-residential customers.

PGE also plans to acquire an additional 80 MW of dispatchable standby generation at customer sites, based on expanding the program at a rate of 13.5 MW per year.

Regarding demand buyback programs, PGE states that it does not yet have adequate estimates of the reliable size of response when it calls buyback events.

PGE is a participant in U.S. Department of Energy's smart appliance program and has submitted a grant proposal with its proposed AMI vendor and an appliance manufacturer to obtain 5 MW to 10 MW of additional demand response resources through an appliance market transformation project.

The company's time of use program has maintained steady participation of nearly 2,000 customers. Pursuant to Commission decisions, the company does not actively market the program in order to keep costs down prior to deployment of AMI, which would avoid one-off installations of interval meters. No customers have signed up for the two-part real-time pricing program.

Guideline 8: Environmental Costs

The company met the Commission's current guidelines for analyzing portfolios.

RNP expressed concern that the company did not consider the likely upcoming changes in the regulatory environment. The Commission is reviewing Guideline 8 in Docket UM 1302. As a party to that docket, RNP presented a survey of current climate change policy proposals which showed a range of carbon adders from $25/ton to $110/ton (2007$). The Commission's current guidelines direct utilities to consider a range of carbon adders up to $40/ton (1990$).

Guideline 9: Direct Access Loads

PGE complies with this guideline. The company does not plan for 5-year opt-out customers (currently approximately 30 aMW).

Guideline 10: Multi-state Utilities

Guideline 10 does not apply.

Guideline 11: Reliability

Under Guideline 11, electric utilities should:

a. Analyze reliability within the risk modeling of the actual portfolios being considered
b. Determine loss of load probability (LOLP), expected planning reserve margin, and expected and worst-case unserved energy by year
c. Demonstrate that the selected portfolio achieves the utility's stated reliability, risk and cost objectives

Staff finds the reliability analysis in PGE's IRP does not meet these requirements. Regarding item a, above, the company analyzed reliability only for its preferred portfolio, not for other portfolios considered. So there's no basis for comparing reliability and cost for the portfolios evaluated.

Toward addressing item b, above, PGE performed stochastic analysis on LOLP, expected unserved energy (in MWa), and both 95th and 99th percentile measures of unserved demand (in MW) for its preferred portfolio, as well as adding to this portfolio 100 MW increments of up to 1,000 MW of additional capacity. However, the company chose a single year, 2012, as the basis for the analysis, instead of providing metrics for each year of the study period as directed by the Commission. Further, because the analysis was performed only on PGE's preferred portfolio, there's no basis to compare the required metrics even among top-performing portfolios.

Regarding item c, above, the IRP did not include an assessment of costs associated with varying levels of reliability, even for PGE's preferred portfolio. However, in response to a request from Staff, the company provided a cost analysis for the preferred portfolio. *See* PGE's response to Staff Data Request No. 2. The analysis compares costs of the portfolio at various capacity reserve levels, based on the costs of three types of simple-cycle combustion turbines, and the corresponding LOLP.

Analysis in the IRP shows that the first 500 MW of capacity reserves reduces LOLP from approximately 16 percent to 3 percent, and the next 500 MW reduces LOLP to nearly zero. The cost analysis requested by Staff indicates such an "inflection point" at approximately $80 million to $90 million, representing the real levelized annual cost of 500 MW to 600 MW of capacity resources, and 2 percent to 3 percent LOLP.

The company finds the cost analysis supportive of its selected level of capacity reserves – a minimum of 500 MW in winter. This approximates a 12 percent planning reserve margin based on projected 2012 winter peak load. Further, 500 MW covers the company's largest generation shaft risks, the Port Westward and Boardman plants.

Staff recommends the following addition to PGE's 2007 IRP Action Plan to address these reliability issues and meet the Commission's reliability guideline:

> *In the next planning cycle, analyze loss of load probability, expected unserved energy, and worst-case unserved energy by year for top-performing portfolios. Analyze the tradeoff between resource adequacy and cost.*

Guideline 12: Distributed Generation

PGE's consideration of distributed generation includes a discussion of combined heat and power (CHP) and opportunities provided by net metering (see section 7.6 of the IRP). However, these resources were not quantified or included in the potential resource mix.

PGE has partnered with several customers to develop dispatchable standby generation (DSG). In PGE's 2002 IRP, it committed to developing a 30 MW virtual peaking plant. PGE attained its goal in June 2006, PGE estimates an additional 80 MW of DSG can be achieved by 2012 and has included this amount in the current action plan.

Guideline 13: Resource Acquisition

a. An electric utility should, in its IRP:

- *Identify its proposed acquisition strategy for each resource in its action plan.*
- *Assess the advantages and disadvantages of owning a resource instead of purchasing power from another party.*
- *Identify any Benchmark Resources it plans to consider in competitive bidding.*

The company complied with these requirements. The company provided its acquisition strategy for its action plan and a brief assessment of the advantages and disadvantages of owning vs. purchasing resources. *See* IRP at 245-246. The company is not including any benchmark resources in the upcoming *energy* RFP. The company is in the process of further analyzing its *capacity* needs and may, in the future, determine an internal benchmark resource prior to issuing a capacity RFP.

b. N/A

III. Initial Recommendations for Acknowledgment of the Action Plan

Staff Data Request No. 5 asked the company to provide its IRP action plan in an itemized table to make it more clear to the Commission what actions it was asking to be acknowledged. Staff recommends acknowledgement of all items in the company's action plan but does so with the following additional recommendations for the next planning cycle:

1. In the next planning cycle, include resources other than market purchases to meet energy needs for at least the first 10 years of the 20-year planning horizon. All resources expected to become available during the resource acquisition period should be considered.

2. In the next planning cycle, include in the analysis a timely wind integration study that has been vetted by key regional stakeholders.

3. In the next planning cycle, complete the portfolio analysis by presenting a rank ordering of the portfolios that considers all of the factors (costs, risks and uncertainties) used to choose the preferred portfolio.

4. For the next IRP: a) establish a set of CO_2 adder levels that covers the gamut of expected environmental regulatory benchmarks; b) match projected loads and gas and electric prices that are economically consistent with those CO_2 adder levels; c) perform the stochastic runs for each of those adder levels/matches; and d) define "risk" for each portfolio at each CO_2 adder level as the TailVaR90 corresponding to the stochastic runs associated with that level.

5. For the 2007 IRP update and next planning cycle, develop and fully evaluate a portfolio that reduces the company's CO2 emissions consistent with the goals expressed in Oregon HB 3543.

6. In the next IRP Update, include an analysis of when transmission construction projects must begin in order to meet the 2012 need.

7. In the next IRP, assess conservation potential for at least the first 10 years of the planning horizon. Include conservation resources in portfolio modeling throughout this resource acquisition period, and include best cost/risk conservation resources in the preferred portfolio.

8. In the next planning cycle, analyze loss of load probability, expected unserved energy, and worst-case unserved energy by year for top-performing portfolios. Analyze the tradeoff between resource adequacy and cost.

Dated at Salem, Oregon this 4th day of January, 2008

Lori Koho

Lori Koho
Senior Analyst
Market & Resource Analysis
Electric & Natural Gas Division

ORDER NO.

ENTERED

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 43

In the Matter of	)	
	)	DRAFT PROPOSED ORDER
Portland General Electric	)	
	)	
2007 Integrated Resource Plan.		

DISPOSITION: PLAN ACKNOWLEDGED WITH REQUIREMENTS FOR NEXT PLANNING CYCLE

INTRODUCTION

On June 29, 2007, Portland General Electric (PGE or the Company) filed its Integrated Resource Plan (IRP). This filing is in accordance with Public Utility Commission of Oregon (Commission) Order No. 07-002, as corrected by Order No. 07-047, [1] which requires all regulated energy utilities operating in Oregon to engage in integrated resource planning.

Requirements for Integrated Resource Planning

The Commission requires regulated energy utilities to prepare integrated resource plans within two years of acknowledgment of the last plan. Utilities must involve the Commission and the public in their planning process, and prior to resource decision-making. Substantively, the Commission requires that energy utilities: (1) evaluate resources on a consistent and comparable basis; (2) consider risk and uncertainty; (3) make the primary goal of the process selecting a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers; and (4) create a plan that is consistent with the long-run public interest as expressed in Oregon and federal energy policies. *See* Order No. 07-002.

The Commission "acknowledges" resource plans that satisfy the procedural and substantive requirements, and that seem reasonable at the time acknowledgment is given.

[1] The Commission originally adopted least-cost planning in Order No. 89-507 (Docket UM 180). The Commission updated the utility planning process in Docket UM 1056.

PGE satisfied Oregon's procedural requirements relating to its planning process. In the analysis below, the Commission identifies specific portions of PGE's filed plan that did not satisfy all of Oregon's substantive planning requirements. However, the Commission concludes that PGE's Action Plan appears reasonable in light of current circumstances with requirements for the next planning cycle described below. Accordingly, the plan is acknowledged with requirements for the next planning cycle.

Implementation Actions for PGE's Preferred Resource Strategy

Based on the analysis described below, PGE selected the Diverse + Contracts portfolio as its preferred course of action. The portfolio includes the following resource additions from 2007 to 2015:

Energy actions total 903 average megawatts (MWa):

- 323 MWa of renewable resources by 2012
- 130 MWa of energy efficiency by 2012
- 70 MWa through renewal of existing contracts (hydro)
- 372 MWa through new contracts, including 180 MWa of purchase power agreements (PPAs) of up to five-year terms and 192 MWa of PPAs of five- to 20-year terms
- 7 MWa through upgrades of existing generation sources

Capacity actions total 1,653 megawatts (MW), including capacity value of the above energy actions plus the following:

- 80 MW of dispatchable standby generation (DSG)
- 35 MW from a curtailable tariff and critical peak pricing enabled by implementation of advanced metering infrastructure
- 25 MW of direct load control
- 100 MW from dual-purpose simple-cycle combustion turbines (SCCTs)
- 299 MW of bi-seasonal demand and supply
- 210 MW of winter-only peak supply

Transmission Actions

- Continue to evaluate the Southern Crossing project and actively work with BPA and others in the region to develop capacity

The Company filed the following Action Plan to implement its preferred portfolio:

1. Energy efficiency acquired by the Energy Trust of Oregon through Public Purpose funds.
    - Size: 85 MWa
    - Resource evaluated in IRP: 85 MWa embedded in load forecast
    - Timing: 2007 through 2012
    - Location: PGE system

2. Pursue 45 MWa of additional energy efficiency through a proposed tariff.
   - Size: 45 MWa
   - Resource evaluated in IRP: Contracts
   - Timing: 2008 through 2012
   - Location: PGE system

3. Invest in efficiency upgrades at the Coyote gas plant and the Pelton Round Butte and Sullivan hydro plants.
   - Size: 7 MWa
   - Resource evaluated in IRP: Contracts
   - Timing: By 2012
   - Location: PGE system

4. Renegotiate hydro contracts that expire by 2012.
   - Size: 70 MWa
   - Resource evaluated in IRP: Contracts
   - Timing: 2011
   - Location: PGE system

5. Complete phases II and III of the Biglow Canyon wind project.
   - Size: 105 MWa
   - Resource evaluated in IRP: Tier I wind
   - Timing: 2009, 2010
   - Location: Columbia Gorge

6. Pursue power purchase agreements with a term of up to five years as a hedge against load uncertainty.
   - Size: 180 MWa
   - Resource evaluated in IRP: Assumed spot market behavior
   - Timing: Ongoing
   - Location: System

7. Pursue intermediate-term power purchase agreements (six- to 10-year terms) to reduce reliance on short-term markets, serve as a bridging strategy, and allow economic dispatch of the Beaver plant for capacity needs.
   - Size: 192 MWa
   - Resource evaluated in IRP: Contracts
   - Timing: By 2015
   - Location: System

8. Procure 218 MWa of additional renewable resources to meet Oregon Renewable Energy Act target of 15% of energy requirements from renewable resources by 2015.
   - Size: 218 MWa
   - Resource evaluated in IRP: Tier II wind, biomass, geothermal
   - Timing: By 2015
   - Location: Pacific Northwest

9. Continue expansion of DSG program at rate of 13.5 MW per year.
   - Size: 80 MW
   - Resource evaluated in IRP: PGE estimate of potential amount and cost
   - Timing: Ongoing
   - Location: PGE System

10. Propose a curtailable tariff for the largest customers; propose a critical peak pricing tariff for small customers upon approval of advanced metering infrastructure.
    - Size: 35 MW
    - Resource evaluated in IRP: Not directly modeled
    - Timing: By 2012
    - Location: PGE System

11. Issue an RFP for direct load control.
    - Size: 25 MW
    - Resource evaluated in IRP: Not directly modeled
    - Timing: By 2012
    - Location: PGE System

12. Issue an RFP for dual-purpose simple-cycle combustion turbines (capacity and wind following).
    - Size: 100 MW
    - Resource evaluated in IRP: SCCT GE 7A, LM6000, LMS100
    - Timing: 2012
    - Location: PGE System

13. Issue an RFP for bi-seasonal supply or demand side to meet peak loads.
    - Size: 299 MW
    - Resource evaluated in IRP: Not directly modeled
    - Timing: By 2012
    - Location: System

14. Issue an RFP for winter-only peak supply.
    - Size: 210 MW
    - Resource evaluated in IRP: Not directly modeled
    - Timing: By 2012
    - Location: System

15. Transmission
    - Continue to investigate Southern Crossing project
    - Continue regional planning activities with BPA and others

Parties' Recommendations

To be completed after final comments are received.

Staff's Final Recommendations - *draft*

Staff recommends the Commission acknowledge Portland General Electric's 2007 IRP with the following requirements for the next planning cycle:

1. In the next planning cycle, include resources other than market purchases to meet energy needs for at least the first 10 years of the 20-year planning horizon. All resources expected to become available during the resource acquisition period will be considered.

2. In the next planning cycle, include in the analysis, a timely wind integration study that has been vetted by key regional stakeholders.

3. In the next planning cycle, complete the portfolio analysis by presenting a rank ordering of the portfolios that considers all of the factors (costs, risks and uncertainties) used to choose the preferred portfolio.

4. For the next IRP: a) establish a set of CO_2 adder levels that covers the gamut of expected environmental regulatory benchmarks; b) match projected loads and gas and electric prices that are economically consistent with those CO_2 adder levels; c) perform the stochastic runs for each of those adder levels/matches; and d) define "risk" for each portfolio at each CO_2 adder level as the TailVaR90 corresponding to the stochastic runs associated with that level.

5. For the 2007 IRP update and next planning cycle, develop and fully evaluate a portfolio that reduces the company's CO2 emissions consistent with the goals expressed in Oregon HB 3543.

6. In the next IRP Update, include an analysis of when transmission construction projects must begin in order to meet the 2012 need.

7. In the next IRP, assess conservation potential for at least the first 10 years of the planning horizon. Include conservation resources in portfolio modeling throughout this resource acquisition period, and include best cost/risk conservation resources in the preferred portfolio.

8. In the next planning cycle, analyze loss of load probability, expected unserved energy, and worst-case unserved energy by year for top-performing portfolios. Analyze the tradeoff between resource adequacy and cost.

DISCUSSION

To be completed after final comments are received.

Jurisdiction

Portland General Electric is a public utility in Oregon, as defined by ORS 757.005, that provides electric service to the public.

On April 20, 1989, pursuant to its authority under ORS 756.515, the Commission issued Order No. 89-507 in Docket UM 180 adopting least-cost planning for all energy utilities in Oregon. On January 8, 2007, the Commission updated its resource planning guidelines in Order No. 07-002 (Docket UM 1056).

CONCLUSION

Portland General Electric is a public utility subject to the jurisdiction of the Commission.

Portland General Electric's 2007 Integrated Resource Plan, as modified in this order, reasonably adheres to the principles of resource planning set forth in Order No. 07-002 and should be acknowledged with the following requirements for the next planning cycle:

1. In the next planning cycle, include resources other than market purchases to meet energy needs for at least the first 10 years of the 20-year planning horizon. All resources expected to become available during the resource acquisition period should be considered.

2. In the next planning cycle, include in the analysis a timely wind integration study that has been vetted by key regional stakeholders.

3. In the next planning cycle, complete the portfolio analysis by presenting a rank ordering of the portfolios that considers all of the factors (costs, risks and uncertainties) used to choose the preferred portfolio..

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7. In the next IRP, assess conservation potential for at least the first 10 years of the planning horizon. Include conservation resources in portfolio modeling throughout this resource acquisition period, and include best cost/risk conservation resources in the preferred portfolio.

8. In the next planning cycle, analyze loss of load probability, expected unserved energy, and worst-case unserved energy by year for top-performing portfolios. Analyze the tradeoff between resource adequacy and cost.

Effect of the Plan on Future Rate-making Actions

Order No. 89-507 set forth the Commission's role in reviewing and acknowledging a utility's least-cost plan as follows:

> The establishment of least-cost planning in Oregon is not intended to alter the basic roles of the Commission and the utility in the regulatory process. The Commission does not intend to usurp the role of utility decision- maker. Utility management will retain full responsibility for making decisions and for accepting the consequences of the decisions. Thus, the utilities will retain their autonomy while having the benefit of the information and opinion contributed by the public and the Commission….

> Acknowledgment of a plan means only that the plan seems reasonable to the Commission at the time the acknowledgment is given. As is noted elsewhere in this order, favorable rate-making treatment is not guaranteed by acknowledgment of a plan. *See* Order No. 89-507 at 6 and 11.

The Commission affirmed these principles in Docket UM 1056.[2]

This order does not constitute a determination on the rate-making treatment of any resource acquisitions or other expenditures undertaken pursuant to Portland General Electric's 2007 IRP. As a legal matter, the Commission must reserve judgment on all rate-making issues. Notwithstanding these legal requirements, we consider the integrated resource planning process to complement the rate-making process. In rate-making proceedings in which the reasonableness of resource acquisitions is considered, the Commission will give considerable weight to utility actions which are consistent with acknowledged integrated resource plans. Utilities will also be expected to explain actions they take which may be inconsistent with Commission-acknowledged plans.

ORDER

IT IS ORDERED that the 2007 Integrated Resource Plan filed by Portland General Electric on June 29, 2007, is acknowledged in accordance with the terms of this order and Order No. 07-002 as corrected by Order No. 07-047.

Made, entered, and effective ______________________________.

______________________________	______________________________
Lee Beyer Chairman	**John Savage** Commissioner
	______________________________
	Ray Baum Commissioner

[2] *See* Order No. 07-002 at 24.

Responses to OPUC Staff comments of June 26, 2007

1 Portfolio standardization

Staff expressed concern that our portfolio analysis uses portfolios of differing resource combinations, but comparable amounts of new energy and capacity. They suggest we should consider also the amount and timing of energy and capacity additions. They also suggest that we have a four-year planning period which "may not comport with the long-term nature of IRP".

Resource Amounts and Timing
Regarding the first point, we agree with Staff that analyzing candidate portfolios with different amounts and timing of energy and capacity additions does provide useful insights. By including our "do-nothing" or "rely on the market" bookend case, we did do the core of what Staff suggests and we did provide analysis of those results in the context of the trade-off between committed fixed costs vs. various risks, particularly that of being short to load requirements. We also provided sensitivities in our public meetings showing the impact of delaying new resources. We are open to additional suggestions and approaches that will improve on analyzing resource timing trade-offs. However such analysis must be in harmony with Order No. 07-002 guidelines No. 1a) and 1c), which state:

1a) all resources must be evaluated on a consistent and comparable basis;
1c) the primary goal must be the selection of resources with the best combination of expected costs and associated risks.

As explained in our public process, we believe that a consistent and comparable basis for the evaluation of alternative candidate resources requires that:

- The alternative resources are evaluated in the same time period, i.e. have the same start date and are dispatched for the same number of years. Failing to do so might distort the performance of any portfolio mix (see page 168 of our IRP).

- The mix of resources added in each portfolio has approximately the same energy and capacity value, i.e. they all meet the same resource adequacy standard.

The issues of *how much* new resource to add, or *when* to add it, are determined by assessing load-resource balance largely without regard to supply portfolios. In effect, the issues of *how much* and *when* are two sides of the same coin. They seek to answer the question of the effects of delaying or accelerating resource actions. In our analysis, we determined that 2012 was a watershed year, in which our resource gap becomes material as the combined result of load growth and resource expirations. Given the resource gap, how much (or when) to add to meet the gap is, in large part, an issue of reliability and resource adequacy considerations, which we also address in the IRP. IRP resource portfolio modeling does not fully inform about *how much* or *when* our customers need resources. Rather, it informs about what mix of resource actions will best fill those needs.

We point out in our IRP that fine-tuning of the plan with regard to timing will be left to implementation based on RFP offerings. For instance, we noted in our proposed action plan that Energy Efficiency and some Demand Response activities will be started right away, while wind will be added in steps from now through 2014.

In our IRP, our market portfolio informs as to the consequences of acquiring longer-term resources in advance of, or after, the demonstrated physical need. More specifically, adding resources in different years triggers the following biases:

- Postponing an investment reduces the expected net present value of the cost of a resource because of financial discounting of fixed investment costs combined with assumed less expensive spot market purchases. But such a strategy also has less reliability and does a poor job of hedging against volatile market costs.
- Adding resources in differing years implies testing their economic value using changing input assumptions and/or increasing the time-frame of the analysis. This increases modeling run times and results in portfolios with differing supply reliability.

We chose to test portfolios with the same capacity and energy values in order to impose the same quality of service on all portfolios. However, we also tested several alternative portfolios with different resource timing, but the same resource mix, and we shared our insights from these results in our April 9, 2007 public meeting (see slides 9 and 10). Given our assumptions on the cost of spot purchases in the WECC (see paragraph 10.2 of the IRP), these alternative portfolios lowered expected overall costs but had higher risk. Specifically, the NPV variable cost exposure was greater than the NPV change to fixed costs. Because portfolios with resource delays do a poor job of meeting resource adequacy targets, we focused on meeting resource needs in the years when material gaps emerge.

Planning Horizon

Regarding the suggestion that PGE uses a four year planning period, we believe this is an incorrect conclusion about an inherently complex issue. It is true that PGE's resource procurement philosophy is to focus on those resource decisions that need to be made prior to or via our next RFP. Subsequent resource decisions will then be made with newer information in the next IRP cycle. For this reason, IRPs and associated RFPs should be conducted on an ongoing, cyclical basis. We believe that making assumptions that cannot be substantiated at this time about, for instance, construction of new nuclear plants or the penetration of plug-in hybrid vehicles by the 2020's is not a reliable basis on which to make resource decisions for customer needs that begin in 2012.

However, despite our focusing resource decisions on customer needs that begin in 2012, it is not true that PGE has a four-year planning horizon. With each resource we evaluate, we use the net present value of its life-cycle fixed revenue requirements combined with twenty years of associated dispatch cost. (We originally modeled longer dispatch periods. Beyond increasingly unreliable fuel cost forecasts, we found that the discounted cost streams for resource dispatch after 20 years tended to make little difference to overall revenue requirements.)

Hence, we are looking twenty years and more into the future. But we do so with today's resource technologies and costs. The goal of an IRP should be to better inform an RFP. Subsequent results of the RFP should then be, barring unforeseeable circumstances, generally congruent with acknowledged IRP proposed actions. Our philosophy is to move the IRP from being an academic exercise to one that is practical and informative for the next round of resource decisions we must make using existing and known resource choices and costs.

We were fairly careful to lay out our analytical approach through the year-long public process, and during that time received verbal support from participants that they felt our approach made sense. We also rely on the IRP guidelines to inform our approach. Guideline 1c directs that "The planning horizon for analyzing resource choices should be at least 20 years and account for end effects." This is precisely what we have tried to do. The guidelines do not tell us to choose resources for the next 20 years and then model all of those for at least another 20 years.

We wish to emphasize that the scope of our IRP is to identify a resource mix that secures reliable electricity supply at the best combination of cost and risk based on resources that can actually be procured in the market today or in the very near future. To reach this target, we imposed some specific modeling constraints designed to reinforce our ability to have careful apples-to-apples portfolio comparisons:

- Avoid speculative assumptions on investment costs and fuel prices beyond what could be reasonably documented (for example, most fuel forecasts do not go beyond 20 years);
- Do not simulate resource additions in a distant future in order to avoid biasing the portfolio performance because of increasingly speculative long-term decisions;
- Freeze PGE portfolio load after 2014, leave resource decisions after 2014 to the next IRP and focus on the identification of the best resources to acquire now;
- Keep the modeling simple and easy to implement: a long run time is an obstacle to timely analysis;
- Leave any decision about the actual timing of new resource additions to the RFP. The optimal timing will depend both on the actual availability of new resources (that we will know after a market solicitation) and on PGE's financial constraints.

2 <u>Direct Load Control</u>

Staff raises three concerns regarding Direct Load Control, two of which come from the following paragraph in our draft IRP:

> *"[Our proposed Capacity Action Plan includes:] Implementation of retail customer curtailment tariffs and direct load control for fifty hours or less per year, once advanced metering infrastructure is in place at the end of this decade. Due to increasing capacity needs that take place over a very small portion of the year, we believe that it makes sense to maintain system reliability by first seeking firm actions from our customers." (Draft IRP at 12).*

The first concern is that "the statement appears to imply that direct load control is not firm." We did not intend to make this implication. The second sentence was intended to be an affirmation of the first sentence. PGE will first request curtailment and direct load control from our customers (i.e., before taking major new supply-side capacity-only actions). We view these as firm capacity resources and show them as such, as explained in response to the third concern below.

The second concern stated by Staff is that "PGE appears to indicate that direct load control should be delayed until deployment of [an] advanced metering infrastructure (AMI) is complete." Direct load control can be implemented without an AMI, and PGE is in the process of developing a request for proposals for third party implementation of demand side capacity outside of the deployment of an AMI. Note that doing so opens the risk that a third party communication system could be incompatible with an AMI once it is fully deployed. This will be ameliorated as best as possible through the specification process. At this time, though, PGE cannot guarantee that communications platforms will not be duplicated.

The third concern is that the capacity contribution from Direct Load Control (DLC) is not included in

PGE's Tables 3-5 and 3-6. That is correct, but not because DLC has no capacity contribution. Those tables in Chapter 3 are a description of PGE 2012 peaking requirements and *existing* generation and contract capacity capability by 2012. It is an assessment of what our capacity resource gap will be in 2012 before new resource actions. For instance, note in the first column of Table 3-5 that PGE's one-hour winter generating capability in 2012 is projected to be 3,050 MW before any new resource actions. This number is also found in Table ES-2 before any proposed actions. We do then subsequently show the capacity contribution from DLC, as a separate line item, in Table ES-2.

3 Time of Use Pricing

Staff recommends more description of the Time of Use Pricing Plan option (TOU) including the number of participants, estimated peak load reductions, and estimated customer savings by customer class.

PGE currently has 1,723 Schedule 7 (residential) and 124 Schedule 32 (small non-residential) customers enrolled in TOU. This participation level has been fairly consistent since the inception of the pricing option in March 2002.

The Portfolio Options Committee (POC), the stakeholder group formed to oversee TOU and Renewables portfolio programs on behalf of the OPUC, in a memo to OPUC Staff for the Commission on July 12, 2005, recommended that utilities minimize marketing costs of the TOU program, including a recommendation to discontinue efforts to evaluate the program for 2006. A similar recommendation for minimizing 2007 costs was made in 2006. PGE's evaluation prior to that recommendation showed that residential peak load was, on average, 0.27 kW (15%) and 0.13 kW (7%) lower than that of a control group during the winter morning and evening peak periods respectively. (Source: "Analysis of the Load Impacts and Economic Benefits of the Residential TOU Rate Option" prepared by Quantec, LLC, March 29, 2004). Summer peak load impacts averaged 0.03 kW (2%) lower. Analysis of non-residential data was not conducted due to the small number of enrolled customers.

A recent informal review of TOU residential customer savings indicates that average annual savings are $34.79, or 5.7% of their bill. Small Non-Residential customers saved $24.18 annually, or 6.2%.

4 Renewable Energy Standard (RES)

Staff is correct in clarifying that use of Tradable Renewable Energy Credits (TRCs, commonly known as Renewable Energy Credits (RECs) or Green Tags) is limited to 20 percent of the target amount in the Oregon RES legislation. Because our proposed plan relies solely on new physical renewable resources dedicated to serve PGE load to meet our RES requirements through 2015 (and assuming competitive pricing for RES qualifying renewables is received via our RFP process), we do not plan to rely on this option between now and 2015. Thus, we did not consider this feature of the legislation to be particularly restrictive to our proposed resource plan.

5 Emerging Resource Technologies

Staff asks if we have "considered funding opportunities from the ETO that may enable purchases from [emerging renewable] resources". Such resources cited by Staff include solar thermal, PV, and wave energy demonstration projects. Section 7.7 of our IRP surveys these and several other emerging technologies. We also describe our current support to local demonstration projects for microturbines, solar, and biogas applications.

Our statement in the IRP about "not considering" these and other emerging technologies was made strictly in the context of economic, utility-scale projects that could be constructed and in-service by 2012. We are indeed currently considering additional demonstration and small-scale opportunities beyond those discussed in the IRP, but did not expound on them due both to the confidential and preliminary nature of such discussions and the inherent evolving nature of the technologies. We also do not focus on them in the IRP due to their relatively small scale. For the IRP, our focus, instead, was generally on larger-scale generation options which are currently commercialized and economic. However, we are in contact with the ETO to understand what funding is available for projects that are 20 MW and smaller.

6 Biomass Potential

Staff suggests that PGE "should review and reference the ETO's contracted assessment" regarding biomass potential. Staff is referring to the Energy Trust's Biomass Market Assessment Final Report, prepared by Itron, dated December 17, 2004. We are reviewing this report. However, we note that our assessment of the market potential for biomass accessible to PGE was obtained from a more recent report (the Western Governor's Association Biomass Task Force Report, dated January 2006). We assumed that the Western Governor's Association report, because it was more recent, contained a more current assessment of the potential for biomass in Oregon.

7 Wind Integration Costs

Staff reminds us that "PGE should update its IRP to reflect the results of its contracted wind integration study." We committed to this in section 7.1 (page 107) of our IRP: "Upon completion of the wind integration study, we intend to update our IRP analysis, if necessary, and also provide a supplement to our IRP." We have recently concluded the preliminary phase of the study referred to in our IRP, but are just entering the subsequent phase described in our study. Ultimately, the real relevance of this data will be to have the latest and best estimates with which to gauge actual RFP proposals.

8 Plug-in Hybrid Vehicles

Staff asks that PGE "describe the potential timing and effect of widespread use of plug-in hybrid [electric] vehicles and battery electric vehicles on its resource plan". They also cite a May 28, 2007 article about the potential of two-way vehicle-to-grid technology which would allow utilities to store power in car batteries during overnight light load hours and return a portion of it during peak hours.

Plug-in hybrids will primarily impact utility systems and its customers in two beneficial ways. First, by putting a predominantly off-peak load onto our system, they allow us to improve the use of generating assets. All else being equal, this should lead to a reduction in the cost per kwh for electricity. Second, upon technological enablement both at the car and at the home, plug-in hybrids could become a source of capacity for relatively short peaking periods. This should further reduce the cost of electricity on a per unit basis.

The latest industry thinking on this topic might be the EPRI summer 2007 research paper entitled: "The Power to Reduce CO2 Emissions" in which plug-in hybrids and other distributed energy resources are relied on as one of six major stabilization wedges (dubbed "prisms" in the report) to slow and then reduce CO2 emissions. It is worth observing that plug-in hybrids are the smallest wedge and are dependent on deployment of a "smart grid" for the demand management aspects. EPRI observes that plug-in hybrids "will become an integral part of the distribution system itself within 20 years, providing storage, emergency supply, and grid stability." Their plan anticipates that 10% of new light vehicle sales by 2017 will be plug-in hybrids, with the ability to reverse power flow to help meet peaking needs by 2020.

Similar to our approach described above regarding emerging resource technologies, in our IRP we focused largely on larger impact items in the 2012 time-frame. Hence, we did not focus on market-transformational end-use changes that still were a few years away from commercial introduction and which we expected to have low initial penetration levels and a gradual ramp in. From a resource perspective in 2012-2014, we do not expect the impact of plug-in hybrids on PGE's electric grid and load shapes to be significant enough to our proximate major generating resource decisions as to warrant additional focus. This topic may be ready for a more robust treatment in our next IRP cycle. The chief impact as it relates to generating resources will be to reduce our need for additional seasonal peaking supply.

9 Energy Efficiency (EE)

IRP guideline 6(c) of Order 07-002 requires an analysis of conservation with and without funding limits. Staff suggests that we were not clear "whether the 44.9 aMW of additional EE potential in PGE's service territory was determined 'without regard to any limits on funding'".

A 2006 Energy Trust of Oregon (ETO) resource assessment performed by Stellar Processes and Ecotope indicated 288 MWa of technical EE potential among PGE's customers. PGE accepted this figure as the technical potential, meaning all energy efficiency that could be achieved without regard to cost. From that point, the ETO and PGE worked together to determine how much was achievable through customer acceptance and how much was cost effective. Cost-effectiveness was based on the avoided cost of base-load supply-side alternatives plus an additional 10%. The ETO's forecast for their acquisition based on current system benefit charge (SBC) funding was then deducted and the 44.9 aMW is the amount remaining that PGE believes is practical to achieve through 2012 without regarding to funding limits. That is, the 44.9 aMW is that additional cost-effective amount that we jointly believe can be acquired between now and the end of 2012 by exceeding current SBC funding limits. In fact, PGE helped place language in the recently passed SB 838 to allow for utility funding of EE beyond the current SBC mechanism.

As described in the IRP filed with the Commission on June 29, 2007, PGE and the ETO have worked together to develop processes for the ETO's administration of incremental funds to supplement market transformation, marketing efforts, and incentives for ETO programs. PGE does not intend to develop and run its own EE programs.

Please refer to section 4.1 of our IRP report for a fuller discussion of the foregoing.

October 17, 2007

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
LC-43
PGE Response to OPUC Data Request
Dated October 03, 2007
Question No. 001

Request:

Please explain what actions the company included in its 2007 IRP to meet customer resource needs beyond 2012, taking into account projected load growth, contract expirations, plant deratings, plant retirements, and other projected resource changes.

Response:

Attachment 001-A is an Excel spreadsheet, DR_001_Attach A.xls, which shows PGE's projected load-resource balance through 2030, including forecasted load growth and resource declines. The 2012 energy load-resource gap of 818 MWa in cell I-35 of the attachment (energy worksheet) is the same as that shown on Figures ES-2 and 3-4 of the 2007 Integrated Resource Plan (IRP). The 2012 winter and summer capacity gaps of 1,540 MW and 1,329 MW in cells I-42 and I-39 (winter and summer capacity worksheets) are the same as those shown in Figures 3-5 and 3-6 of the IRP. In its analysis, PGE used the following steps to determine what actions needed to be included in the 2007 IRP and what actions needed to be included in future IRPs:

1) We looked at the information contained in Attachment 001-A, as well as additional information, such as the expectation of a renewable portfolio standard. We also considered load uncertainty due to opt-out eligible customers and local economic growth, as well as uncertainty around contract renewals.
2) From this information, we determined approximate quantities and timing of resource acquisitions needed to meet the difference between forecasted loads and existing resources over time.

3) We divided the required resource acquisitions into those that we need to begin acting on prior to our next IRP, and those that are better handled in future IRPs when we have better relevant information.
4) We noted that the resource acquisitions we need to begin acting on prior to our next IRP are those needed to fill the load-resource gap through 2012. As Attachment 001-A shows, in 2012 the load-resource gap increases significantly because of contract expirations. Although further resource additions will be needed to fill the incremental post-2012 gap, we do not need to take actions now, and we can better evaluate the related acquisition strategies in future IRPs. However, in the 2007 IRP, we do factor in renewable requirements through 2015, as 2015 is a major milestone year for the renewable energy source standards included in Senate Bill 838.

   Within the group of resource acquisitions that we need to begin acting on prior to our next IRP, we determined which ones we needed to act on quickly, and those which could wait until we had more information, in substantial part through evaluating bids within a request for proposals process.

Given the discussion above, the 2007 IRP does not include specific resource acquisition actions to address the projected incremental post-2012 load-resource gap. Nonetheless, we are undertaking a number of enablement activities to position and prepare for future needs. These activities include build-out of the AMI system, engaging in regional discussions regarding a possible major new transmission project (Southern Crossing), various Boardman emission compliance activities, and exploration of various demonstration projects and alternative resource development activities, such as solar, wave development, clean coal, and new nuclear technologies.

LC-43
Attachment 001-A

Excel Spreadsheet – Load-Resource Balance

Projected PGE Load / Resource Balance -- Capacity MW -- Base Case
Theoretical Availability Using Average Hydro, Port Westward in 04-2007
Renewal of Tribes contracts, 30 MW on NCOS
(PGE is currently re-assesssing hydro capabilities, PGE and Mid-C hydro can change))

	Jan-07	Jan-08	Jan-09	Jan-10	Jan-11	Jan-12	Jan-13	Jan-14	Jan-15	Jan-16	Jan-17	Jan-18	Jan-19	Jan-20
Plants														
Boardman	380	380	380	380	380	380	377	377	377	377	377	377	377	377
Colstrip	296	296	296	296	296	296	296	296	296	296	296	296	296	296
Beaver	521	521	521	521	521	521	521	521	521	521	521	521	521	521
Beaver 8	24	24	24	24	24	24	24	24	24	24	24	24	24	24
Port Westward	425	425	425	425	425	425	425	425	425	425	425	425	425	425
Coyote	245	245	245	245	245	245	245	245	245	245	245	245	245	245
Biglow Canyon Wind Project		19	19	19	19	19	19	19	19	19	19	19	19	19
Oak Grove	33	33	33	33	33	33	33	33	33	33	33	33	33	33
North Fork	43	43	43	43	43	43	43	43	43	43	43	43	43	43
Faraday	43	43	43	43	43	43	43	43	43	43	43	43	43	43
River Mill	23	23	23	23	23	23	23	23	23	23	23	23	23	23
Bull Run	22	0	0	0	0	0	0	0	0	0	0	0	0	0
Sullivan	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Round Butte	225	225	225	225	225	225	225	225	225	225	225	225	225	225
Pelton	73	73	73	73	73	73	73	73	73	73	73	73	73	73
Total PGE Plants	2,370	2,367	2,367	2,367	2,367	2,367	2,364	2,364	2,364	2,364	2,364	2,364	2,364	2,364
Total Longer-term Contracts	1,523	1,522	1,538	1,417	1,315	683	668	668	642	642	391	362	198	198
Total Resources	**3,893**	**3,889**	**3,905**	**3,784**	**3,681**	**3,050**	**3,032**	**3,032**	**3,006**	**3,005**	**2,755**	**2,726**	**2,562**	**2,562**
Load w/losses (MW)														
Medium growth scenario	3,823	3,870	3,943	4,000	4,054	4,127	4,201	4,277	4,355	4,436	4,516	4,599	4,684	4,772
		1.2%	1.9%	1.4%	1.4%	1.8%	1.8%	1.8%	1.8%	1.9%	1.8%	1.8%	1.8%	1.9%
Opt Out load (MW)	27	28	28	28	29	29	27	27	27	27	27	27	27	27
Operating Reserve Margin	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%
Planning Reserve Margin	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%
Medium growth load + reserves	4,282	4,335	4,416	4,480	4,540	4,623	4,705	4,791	4,878	4,968	5,058	5,151	5,246	5,345
Load for Graph (includes reserves)														
Expected	**4,252**	**4,304**	**4,385**	**4,448**	**4,508**	**4,590**	**4,675**	**4,760**	**4,847**	**4,938**	**5,028**	**5,121**	**5,216**	**5,314**
Growth Rate		1.2%	1.9%	1.4%	1.4%	1.8%	1.9%	1.8%	1.8%	1.9%	1.8%	1.8%	1.9%	1.9%
Growth MW	4,252	53	81	63	60	82	85	85	87	90	90	93	95	99
Load Factor	56.0%	56.3%	56.3%	56.3%	56.4%	56.6%	56.8%	57.0%	57.2%	57.4%	57.6%	57.8%	58.0%	58.1%
Energy Additions	426	337	392	488	564	818	877	939	1,003	1,064	1,222	1,318	1,465	1,532
Shortfall:	359	415	480	664	826	1,540	1,643	1,729	1,842	1,932	2,272	2,395	2,654	2,753
						1,540	in graph							

Projected PGE Load / Resource Balance -- Capacity MW -- Base Case
Theoretical Availability Using Average Hydro, Port Westward in 04-2007
Renewal of Tribes contracts, 30 MW on NCOS
(PGE is currently re-assesssing hydro capabilities, PGE and Mid-C hydro can change))

	Aug-07	Aug-08	Aug-09	Aug-10	Aug-11	Aug-12	Aug-13	Aug-14	Aug-15	Aug-16	Aug-17	Aug-18	Aug-19	Aug-20	Aug-21	Aug-22	Aug-23	Aug-24	Aug-25	Aug-26	Aug-27	Aug-28	Aug-29	Aug-30	
Plants																									
Boardman	380	380	380	380	380	380	380	380	380	380	380	380	380	380	380	380	380	380	380	380	380	380	380	380	Keep Boardman
Colstrip	296	296	296	296	296	296	296	296	296	296	296	296	296	296	296	296	296	296	0	0	0	0	0	0	
Beaver	487	487	487	487	487	487	487	487	487	487	487	487	487	487	487	487	487	487	0	0	0	0	0	0	
Beaver 8	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	0	0	0	0	0	0	
Port Westward	401	401	401	401	401	401	401	401	401	401	401	401	401	401	401	401	401	401	401	401	401	401	401	401	
Coyote	233	233	233	233	233	233	233	233	233	233	233	233	233	233	233	233	233	233	233	0	0	0	0	0	
Biglow Canyon Wind Project	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	
Oak Grove	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	
North Fork	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	
Faraday	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	
River Mill	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	
Bull Run	22	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	Estimate. License expired,
Sullivan	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	
Round Butte	225	225	225	225	225	225	225	225	225	225	225	225	225	225	225	169	169	169	169	169	169	169	169	169	
Pelton	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	55	55	55	55	55	55	55	55	55	
Total PGE Plants	2,217	2,195	2,195	2,195	2,195	2,195	2,195	2,195	2,195	2,195	2,195	2,195	2,195	2,195	2,195	2,120	2,120	2,120	1,313	1,080	1,080	1,080	1,080	1,080	
Total Longer-term Contracts	1,140	1,139	1,156	1,034	1,015	650	695	695	678	678	568	388	220	220	220	220	220	220	220	220	220	212	212	212	
Total Resources	**3,357**	**3,334**	**3,351**	**3,229**	**3,210**	**2,845**	**2,890**	**2,890**	**2,873**	**2,873**	**2,763**	**2,583**	**2,415**	**2,415**	**2,415**	**2,341**	**2,341**	**2,341**	**1,534**	**1,301**	**1,301**	**1,292**	**1,292**	**1,292**	
Load w/losses (MW)																									
Medium growth scenario	3,426	3,485	3,546	3,604	3,663	3,761	3,862	3,965	4,072	4,181	4,294	4,410	4,530	4,652	4,779	4,909	5,043	5,180	5,322	5,468	5,618	5,773	5,931	6,095	
		1.7%	1.8%	1.6%	1.6%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.8%	2.8%	
Opt Out load (MW)	32	32	32	33	33	34	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	0
Operating Reserve Margin	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	
Planning Reserve Margin	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	
Medium growth load + rese	3,837	3,903	3,971	4,036	4,103	4,212	4,325	4,441	4,560	4,683	4,809	4,939	5,073	5,211	5,352	5,498	5,648	5,802	5,961	6,124	6,292	6,465	6,643	6,826	
Load for Graph (includes reserves)																									
Expected	**3,802**	**3,867**	**3,935**	**4,000**	**4,065**	**4,174**	**4,290**	**4,406**	**4,525**	**4,648**	**4,774**	**4,904**	**5,038**	**5,175**	**5,317**	**5,463**	**5,613**	**5,767**	**5,925**	**6,089**	**6,257**	**6,430**	**6,608**	**6,791**	Medium growth, with 73MV
Growth Rate		1.7%	1.8%	1.6%	1.6%	2.7%	2.8%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	
Growth MW	3,802	65	68	64	66	109	116	116	119	123	126	130	134	138	142	146	150	154	159	163	168	173	178	183	
Load Factor	62.6%	62.6%	62.7%	62.6%	62.6%	62.3%	61.9%	61.6%	61.3%	60.9%	60.6%	60.3%	60.0%	59.7%	59.4%	59.1%	58.8%	58.5%	58.2%	57.9%	57.7%	57.4%	57.1%	56.9%	
Energy Additions	58	(31)	24	120	196	449	509	571	635	696	854	949	1,097	1,164	1,232	1,331	1,403	1,473	2,217	2,505	2,585	2,667	2,760	2,846	
Shortfall:	445	533	585	770	856	$\boxed{1,329}$	1,400	1,516	1,652	1,775	2,011	2,321	2,622	2,760	2,902	3,122	3,272	3,426	4,392	4,788	4,956	5,138	5,316	5,499	

Projected PGE Load / Resource Balance -- Annual Average Energy MWa -- Beaver on Economic Dispatch
Theoretical Availability Using Average Hydro
Assumes No Contract Renewal, 30 MWa on NCOS

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Plants																								
Boardman	318	318	318	318	318	318	316	316	316	316	316	316	316	316	**316**	**316**	**316**	**316**	**316**	**316**	**316**	**316**	**316**	**316**
Colstrip	252	252	252	252	252	252	252	252	252	252	252	252	252	252	252	252	252	252	0	0	0	0	0	0
Beaver	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	0	0	0	0	0	0
Beaver 8	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	0	0	0	0	0	0
Port Westward	280	374	374	374	374	374	374	374	374	374	374	374	374	374	374	374	374	374	374	374	374	374	374	374
Coyote	210	210	210	210	210	210	210	210	210	210	210	210	210	210	210	210	210	210	210	0	0	0	0	0
Biglow Canyon Wind Project		47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47
Oak Grove	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
North Fork	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27
Faraday	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
River Mill	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
Bull Run	11	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sullivan	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
Round Butte	76	76	75	75	75	75	75	75	75	75	75	75	75	75	75	56	56	56	56	56	56	56	56	56
Pelton	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	25	25	25	25	25	25	25	25	25
Total PGE Plants	1,333	1,466	1,461	1,461	1,461	1,461	1,458	1,458	1,458	1,458	1,458	1,458	1,458	1,458	1,458	1,431	1,431	1,431	1,130	919	919	919	919	919
Total Longer-term Contracts	620	620	615	557	520	322	320	315	310	310	214	181	99	99	99	99	99	103	104	104	104	104	96	96
Total Resources	**1,953**	**2,085**	**2,075**	**2,017**	**1,980**	**1,782**	**1,779**	**1,774**	**1,769**	**1,769**	**1,672**	**1,640**	**1,558**	**1,558**	**1,558**	**1,530**	**1,530**	**1,534**	**1,234**	**1,024**	**1,024**	**1,024**	**1,015**	**1,015**
Load w/losses (MWa)																								
Medium growth scenario	2,407	2,451	2,496	2,536	2,574	2,630	2,686	2,743	2,802	2,862	2,924	2,988	3,053	3,120	3,188	3,258	3,331	3,405	3,481	3,559	3,639	3,721	3,805	3,892
Opt Out load (MWa)																								
5-yr opt out -->Sch483 in 20	28	29	29	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Net Retail COS Load	**2,379**	**2,422**	**2,467**	**2,506**	**2,544**	**2,600**	**2,656**	**2,713**	**2,772**	**2,832**	**2,894**	**2,958**	**3,023**	**3,090**	**3,158**	**3,228**	**3,301**	**3,375**	**3,451**	**3,529**	**3,609**	**3,691**	**3,775**	**3,862**
Annual Average Energy Need:	426	337	392	488	564	818	877	939	1,003	1,064	1,222	1,318	1,465	1,532	1,600	1,699	1,771	1,841	2,217	2,505	2,585	2,667	2,760	2,846

October 17, 2007

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
LC-43
PGE Response to OPUC Data Request
Dated October 03, 2007
Question No. 002

Request:

Please explain how the 2007 IRP considers the cost-risk tradeoff of higher vs. lower reliability. For example, did the company compare cost and risk metrics of resource portfolios with varying reliability metrics such as loss of load probability and expected and worst-case unserved energy?

Response:

This response has two parts. First, we address specific cost and risk metrics. Next, we summarize the factors that go into the IRP capacity resource recommendations.

Cost and Risk Metrics:

Figures 12-4 and 12-5 of the IRP consider capacity reserve levels and three corresponding risk metrics – loss of load probability (LOLP, expressed in % of hours in the year), expected unserved energy (expressed in annual MWa), and both 95th and 99th percentile measures of unserved demand (expressed in MW). Figure 1 below compares costs for various capacity reserve levels and the corresponding risk metric of LOLP. The costs are real (2006$) annual costs (real levelized annual fixed costs, plus 2012 variable costs) required to meet given LOLP levels based on three types of simple-cycle combustion turbines – LM 6000, GE 7Fa, and LMS 100.

Figures 1 below exhibits the same characteristics as Figures 12-4 and 12-5 of the IRP. Large reliability improvements are achieved with initial reserve acquisitions, but a point is eventually reached in which additional investment in reserves yields comparatively small gains in reliability. Achieving an LOLP of less than approximately 2-3% becomes increasingly expensive, in terms either of capacity resources needed (i.e. more than approximately 500-600 MW in Figures 12-4 and 12-5) or cost (i.e. more than the approximately $80-90 million per year needed to achieve approximately 2-3% LOLP). For example, in Figure 12-4, there is an inflection point at approximately 500-600 MW and 2-3% LOLP. The first 500 MW of capacity reserve reduces LOLP from approximately 16% to approximately 3%, but the next 500 MW reduces LOLP by only approximately 3% (to close to zero). There are corresponding inflection points in Figure 1 below, at approximately $80-90 million (the real levelized annual cost of approximately 500-600 MW of capacity resources) and 2-3% LOLP.

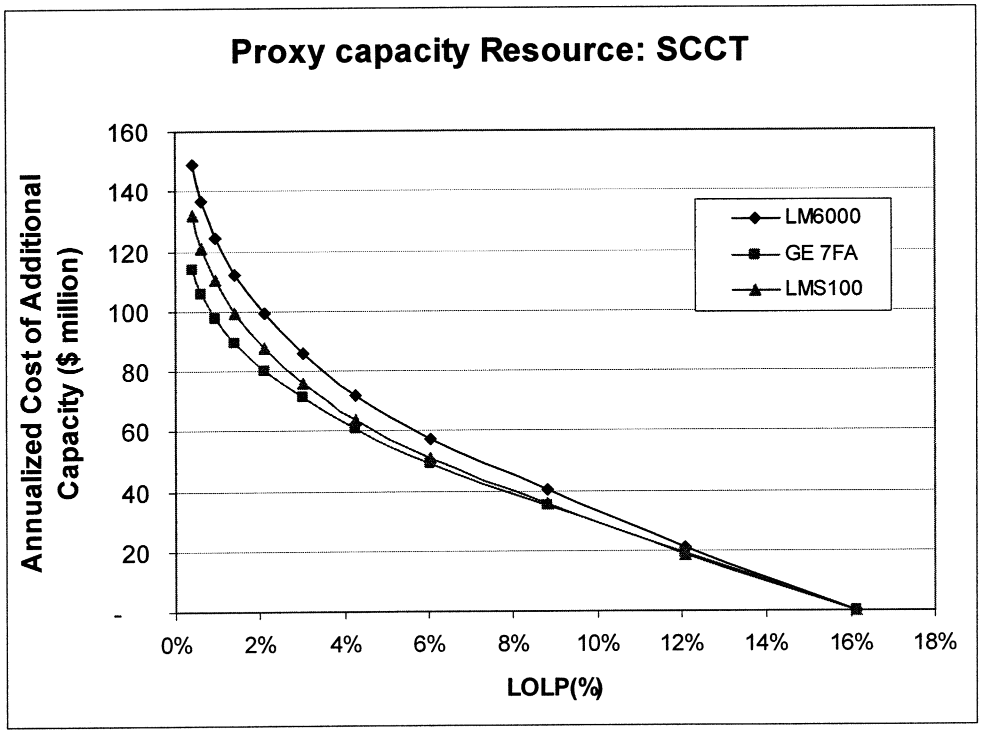


Figure 1

Other Resource Adequacy Considerations:

"How many capacity resources are necessary?" is more complex than insurance because PGE has an obligation to meet customer load and PGE's ability to do so is also impacted by distribution system outages related to wind and ice storms. We need enough capacity resources to meet load requirements under all but the most extreme situations, but there is still a cost aspect, as discussed above.

Our action plan recommends a minimum of 500 MW in (winter) capacity reserve (see Table 13-2 of IRP). This level is based on the following considerations:

- The specific capacity level and associated cost vs. risk metrics discussed above.

- 500 MW is approximately 12% of our projected 2012 winter peak load (note that we used this 12% standard in our 2002 IRP.
- 500 MW is slightly higher than the *physical* standard proposed by the Northwest Power and Conservation Council. However, Council work also suggests that a (by a particular economic measure) optimal standard for the region is significantly higher than the physical standard.
- 500 MW is sufficient to cover either of our largest single generation shaft risks, Port Westward and Boardman.

October 17, 2007

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
LC-43
PGE Response to OPUC Data Request
Dated October 03, 2007
Question No. 005

Request:

Please provide, in table format, a list of proposed actions PGE is requesting the Commission to acknowledge. Please number the action items for the convenience of staff, parties and the Commission. PGE may refer to Table 8.2 (page 224) of PacifiCorp's 2007 Integrated Resource plan for a suggested format.

Response:

Attachment 005-A provides the requested information in an Excel file, DR_005_Attach A.xls.

LC-43
Attachment 005-A

Excel File: Action Plan

2007 IRP Action Plan

Action Item	Category	Action Type	Calendar-Year Timing	Size	Location	IRP Proxy Resource Modeled	Action
1	Demand-Side	Energy Efficiency	Ongoing	85 MWa	PGE System	Embedded in load forecast	No action required. This is the expected impact on our load of the planned ETO targets based on utilization of our customers' public purpose funds
2	Demand-Side	Energy Efficiency	2008 thru 2012	45 MWa	PGE System	Contract	Pursue cost-effective EE that current ETO funding is not sufficient to reach
3	Supply-Side	Existing resources upgrades	Ongoing	7 MWa	PGE System	Generic contract with energy and capacity value equal to expected efficiency upgrades by 2012	Invest in efficiency upgrades at the Pelton Round Butte and Sullivan hydro plants and the Coyote gas plant which will deliver more energy for no additional fuel
4	Supply-Side	Renewal of existing contracts	2011	70 MWa	PGE System	Contract	Renegotiate exipiring hydro contracts
5	Renewables	New Renewables: Wind	2009, 2010	105 MWa	Columbia Gorge	Wind - Tier I	Complete the Biglow Canyon project.
6	Supply-Side	New long-term contracts for baseload energy	Ongoing	180 MWa	System	Assumed spot market behavior	Engage in PPAs of up to 5-year terms for load uncertainty
7	Supply-Side	New long-term contracts for baseload energy	by 2015	192 MWa	System	Contract	Pursue intermediate-term PPAs are targeted at 5 to 20 years. Securing intermediate term contracts will help us better meet our energy supply needs resulting from the economic dispatch of our Beaver plant. Beaver remains available as before for economic dispatch and capacity requirements. This action reduces our physical and financial reliance on short-term volatile markets and provides a bridge to allow technology developments to mature (e.g., IGCC) and energy and environmental policy implications to become clearer
8	Supply-Side	New Renewables: wind, geothermal, biomass, solar, etc.	by 2015	218 MWa	Pacific Northwest	Wind-Tier II, biomass, geothermal	Achieve the 2015 Oregon RES target of 15% of our annual energy requirements. Based on current assumptions about cost and risk exposures of competing resources, and based on our existing resource mix, our analysis concludes that acquiring renewable resources is preferred. This Action Plan recommendation is, however, predicated on continuance of the PTC in substantially its same form. It also assumes that sufficient viable projects exist to fill the demand at competitive prices
9	Demand-Side	Demand-side, peak load	Ongoing	80 MW	PGE System	PGE estimate of potential MW and expected cost	Continue of DSG program @ 13.5 MW / Yr.
10	Demand-Side	Demand-side, peak load	by 2012	35 MW	PGE System	Not directly modeled	Propose a curtailment tariff, critical peak pricing. Upon approval of our advanced metering infrastructure, PGE is planning to issue a tariff to implement critical peak pricing for residential customers. This program will provide insights about available capacity, allowing us to further refine this estimate
11	Demand-Side	Demand-side, peak load	by 2012	25 MW	PGE System	Not directly modeled	Issue RFP for direct load control (space & water heat, A/C)
12	Supply-Side	Supply-side, peak load	2012	100 MW	PGE System	SCCT: GE 7A, LM6000, LMS100	Issue RFP for dual-purpose (Capacity + Wind following) SCCTs
13	Demand and Supply-Side	Seasonal supply or demand side, peak load	by 2012	299 MW	System	Not directly modeled	Issue RFP for bi-seasonal via demand and supply
14	Supply-Side	Winter supply, peak load	by 2012	210 MW	System	Not directly modeled	Issue RFP for Winter-only peak supply
15	Transmission	Southern Crossing and inter-regional transmission projects	ongoing	n.a.	n.a	Not directly modeled	Continue to evaluate the Southern Crossing project and to actively work with BPA and others to develop transmission capacity over the Cascades so that additional, competitive resources are accessible to PGE

December 04, 2007

TO: Vikie Bailey-Goggins
Oregon Public Utility Commission

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
LC-43
PGE *Revised* Response to OPUC Data Request
Dated November 8, 2007
Question No. 007

Request:

Please explain what actions the company is taking or will take to assure completion of the wind integration study. In your response, please include:

- **A timeline with action items, lead staff and weekly updates to OPUC.**
- **A discussion of efforts PGE has already taken to push completion of this study.**
- **A copy of the contract PGE executed with the consultant who is performing the study.**
- **A discussion of the options should the company find itself unable to deliver a completed study to OPUC and parties prior to November 23, 2007. This is the minimum time Staff and parties need to review the study prior to the due date for Staff to submit their initial comments, recommendations and draft order (December 4, 2007 according to the schedule agreed to by parties during the LC-43 prehearing conference). Options might include:**
  - **Hiring a new contractor**
  - **Obtaining resources internally (software and manpower) to perform the modeling the contractor is requesting**
  - **Contracting with a third party to perform the requested modeling**
  - **Proposing an interim proxy for the study that has been vetted by regional experts (Renewable Northwest Project, NW Power & Conservation Council, etc.)**

Response (Revised 12-04-07):

Conducting a wind integration study has taken longer and become more complex than PGE expected when we first initiated the study. This is due in part to the inherent complexity of the task, but it is also due to the evolving scope of the study. When we first began the study, we were focused on the three phases of the Biglow Canyon wind project (approximately 425 MW). As we completed our IRP analysis and developed an Oregon Renewable Energy Standard compliant preferred Action Plan, it became clear that we needed to expand the scope of the wind study another 500 MW beyond the original 425 MW, requiring additional wind data and commensurately expanded use of hydro and thermal resources for integration.

When our consultant completed the original work, PGE staff found itself time and resource constrained from pursuing the subsequent steps, as further described below.

In lieu of the completed wind integration study, to be responsive to the core concern about resource selections should costs be lower that what we have assumed in the IRP, we have run sensitivities in Aurora regarding the expected cost of wind integration and its effect on PGE's Action Plan. As detailed below, we found that our Action Plan does not change if wind integration costs for post-Biglow Canyon wind are $4/MWh higher or lower than the initial IRP assumption of $10/MWh.

The remainder of our response is organized as follows:

- Contract with EnerNex
- PGE resources
- Completed work
- Our plan of action
- Impact of windintegration cost uncertainty on Action Plan

<u>Contract with EnerNex</u>
PGE contracted with EnerNex in mid-February, 2007, to perform a wind integration study. See the contract labeled as Attachments 007-A, which is confidential and subject to Protective Order No. 07-441. For some parts of the study, EnerNex required inputs from PGE. These inputs included wind data and a power cost model with the ability to evaluate pre-schedule and hour-ahead forecasting issues.

<u>PGE resources</u>
As PGE worked with EnerNex on the wind integration study, we realized that our existing models would not facilitate the EnerNex study. Unfortunately, by this time, we were near completion of the original study. Further, PGE employees who could potentially provide the modeling solutions were engaged in other modeling activities concerning the real time operations of our system and with net variable power cost modeling for various regulatory dockets. With these employees not available, PGE was not able to provide EnerNex with all of the inputs and support it needed to advance the study within the desired timeframe.

<u>Completed work</u>
We are currently considering four potential components of wind integration costs– regulating margin, load following, pre-schedule forecast error, and hour(s)-ahead forecast error. EnerNex has completed work to estimate regulating margin and load following costs for the original Biglow Canyon project scope. PGE itself has done preliminary work on pre-schedule forecast error.. The primary missing components are an estimate of the costs resulting from hour(s)-ahead forecast error and analysis for post-Biglow Canyon

wind. EnerNex has completed all work that it could do without access to an appropriate PGE-specific model and additional wind data, and should not be looked to as an impediment to our completion of the study. While components of the study are completed, the study is not modular and thus useful conclusions cannot be drawn until the remaining work is completed.

Plan of action

PGE is currently studying if the costs associated with hour(s)-ahead forecast errors can be estimated using Monet resource dispatch logic or the Aurora model. If neither model can be modified or adapted to perform the work, we will most likely acquire a third-party model and then adapt it for PGE-specific use.

Our revised goal is to have the study completed in time to evaluate the renewables bids. This will give us results for when it is most crucial – during the cost assessment of actual proposals.

PGE has informed Staff of the delays in our wind integration studies in this and other dockets (e.g., UE 188). Parties in those dockets decided to use a stipulated wind integration cost for Biglow Canyon phase 1 because the study would not be completed in time. As we discuss below, wind integration costs between $6/MWh and $14/MWh do not change PGE's proposed Action Plan. Nevertheless, PGE agrees that a robust wind integration study is necessary and we are willing to provide periodic updates to Staff as well as answer informal Staff questions.

Impact of wind integration cost uncertainty on Action Plan

Revised Attachment 007-B provides results of integration cost sensitivities on PGE's Action Plan. These results also include the updated CO_2 and gas price inputs contained in PGE's November 9, 2007, Reply Comments. *Revised* Attachments 007-B-1 through 007-B-3 show the resource portfolio efficient frontier under a range of integration cost assumptions. *Revised* Attachment 007-B-1 is consistent with our Reply Comments in all respects and uses the original IRP assumption for wind integration costs. *Revised* Attachment 007-B-2 assumes lower wind integration costs. Specifically, it assumes that Tier II wind integration costs (i.e., wind integration for projects after full build-out of the Biglow Canyon project) are $6/MWh ($2006), rather than $10/MWh (see Page 107 of 2007 IRP). We chose $6/MWh for Tier II wind to be consistent with what we assumed for the Biglow Canyon Tier I wind (also $6/MWh). We chose it strictly for the sake of convenience and consistency in modeling, as a reasonable value to test. *Revised* Attachment 007-B-3 assumes higher wind integration costs in order to test the response to higher than assumed costs and provide a broader range of sensitivities with which to test the impact of varying wind integration costs. Specifically, it assumes that Tier II integration costs are $14/MWh ($2006), rather than $10/MWh.

Revised Attachments 007-B-1 through 007-B-3 show that the positions of various portfolios relative to each other do not change significantly, albeit, wind-dominated portfolios improve. (To give context to the $4/MWh sensitivity, recall that PGE's assumed fully-allocated levelized cost for a post-Biglow wind farm in our IRP was about $70/MWh. Also note that in these sensitivities we have not updated generation capital costs, which have the potential to have a larger impact.) PGE's preferred resource Action Plan does not change over the range of values that we tested.

LC-43
Attachment 007-A
(See Response filed 11-26-07)

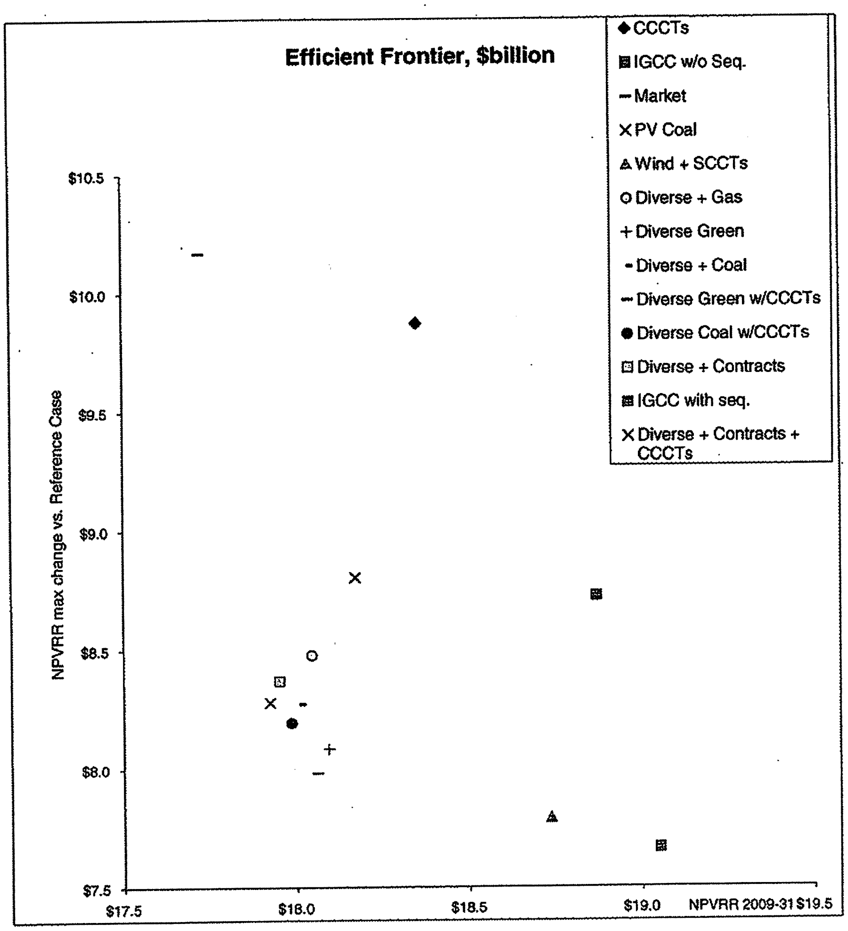
Confidential and Subject to Protective Order No. 07-441

EnerNex Contract

LC-43
Attachment 007-B-1
(Revised 12-4-07)

Efficiency Frontier
Base Case Wind Integration Cost Assumptions

LC-43
Revised PGE Response to
OPUC Data Request No. 007
Revised Attachment 007-B1



Updated expansion:

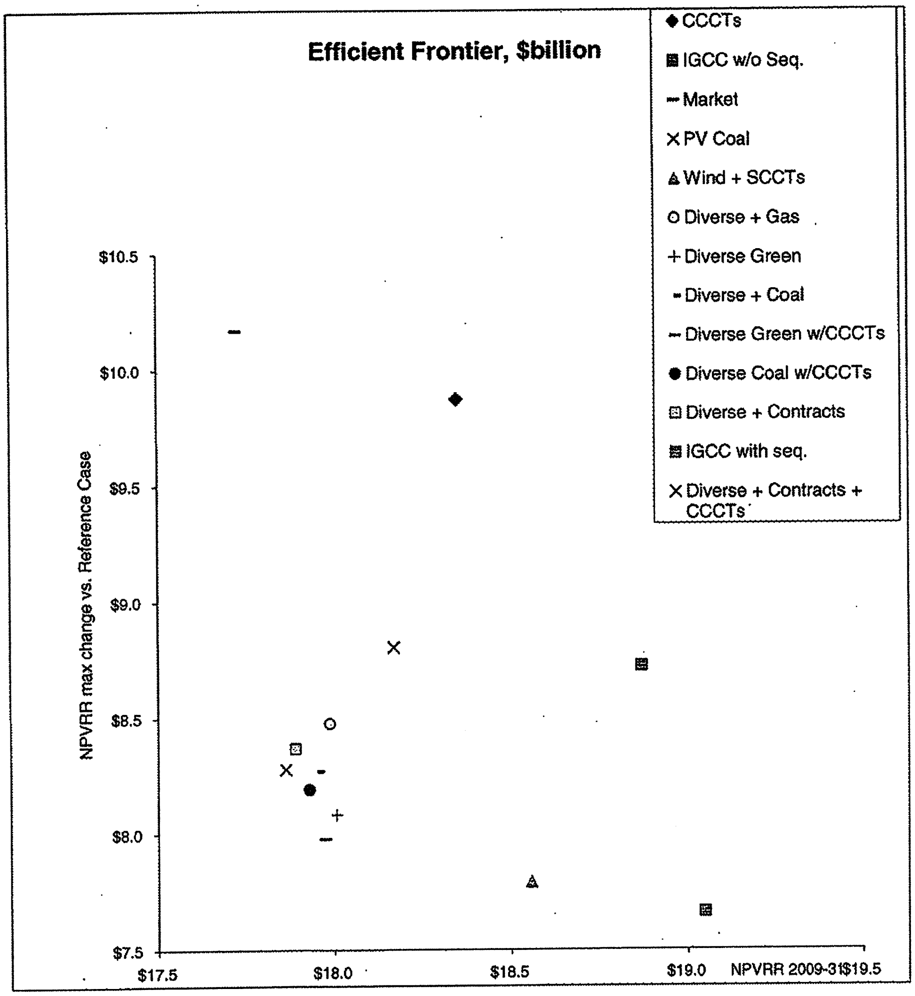
- updated gas forecast
- $12 CO2 in 2012, rising 5% real

Tier 2 wind integration at $10/mwh (original IRP assumption)

LC-43
Attachment 007-B-2
(Revised 12-4-07)

Efficiency Frontier
Lower Wind Integration Cost Sensitivity

LC-43
Revised PGE Response to
OPUC Data Request No. 007
Revised Attachment 007-B2



Updated expansion:

- updated gas forecast
- $12 CO_2 in 2012, rising 5% real

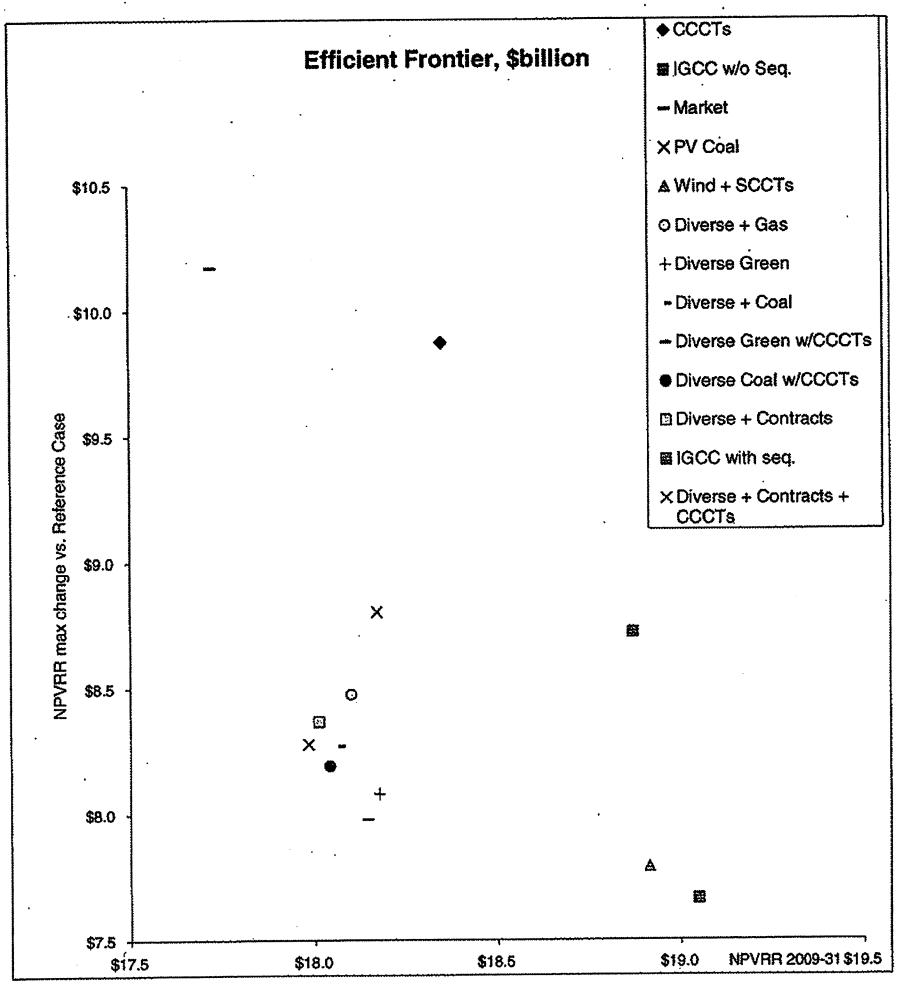
Tier 2 wind integration at $6/mwh

November 21, 2007

LC-43
Attachment 007-B-3
(Revised 12-04-07)

Efficiency Frontier
Higher Wind Integration Cost Sensitivity

LC-43
Revised PGE Response to
OPUC Data Request No. 007
Revised Attachment 007-B3



Updated expansion:

- updated gas forecast
- $12 CO2 in 2012, rising 5% real

Tier 2 wind integration at $14/mwh

November 21, 2007

CERTIFICATE OF SERVICE

LC 43

I certify that I have this day served the foregoing document upon all parties of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, or by electronic mail pursuant to OAR 860-13-0070, to the following parties or attorneys of parties.

Dated at Salem, Oregon, this 4th day of January, 2008.

Kay Barnes

Kay Barnes
Public Utility Commission
Regulatory Operations
550 Capitol St NE Ste 215
Salem, Oregon 97301-2551
Telephone: (503) 378-5763

LC 43
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